COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS RATES	**)))**	**CASE NO. 2018-00294**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

on behalf of

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Adrien M. McKenzie, and my business address is 3907 Red River, Austin, Texas 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am President of Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A3. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit No. 1.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to present to the Kentucky Public Service Commission ("KPSC") my independent assessment of the fair rate of return on equity ("ROE") that Louisville Gas and Electric Company ("LGE") and Kentucky Utilities Company ("KU") should be authorized to earn on their investment in providing electric and gas utility service.[1] In addition, I also examined the reasonableness of the Companies' capital structure, considering both the specific risks faced by LGE/KU, as well as other industry guidelines.

Q5. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A5. To prepare my testimony, I referenced information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the

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[1] I refer to LGE and KU collectively as "LGE/KU" or "the Companies."

organization, finances, and operations of LGE and KU from my participation in prior proceedings before the KPSC, the Virginia State Corporation Commission ("VSCC"), and the Federal Energy Regulatory Commission ("FERC"). In connection with this filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to LGE/KU. I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for the Companies, and they form the basis of my analyses and conclusions.

Q6. HOW IS YOUR TESTIMONY ORGANIZED?

A6. After first summarizing my conclusions and recommendations, I briefly review the operations and finances of LGE and KU. I then examine current conditions in the capital markets and their implications in evaluating a fair ROE for the Companies. With this as a background, I conduct well-accepted quantitative analyses to estimate the current cost of equity for a reference group of comparable-risk utilities. These included the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of Capital Asset Pricing Model ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for utilities, which are all methods that are commonly relied on in regulatory proceedings. In addition, I discuss the proper use of data from Regulatory Research Associates ("RRA") in reviewing recommendations concerning the required ROE and explain why the development and consideration of substantial record evidence is necessary to meet the regulatory principles set forth by the U.S. Supreme Court in the *Bluefield*[2] and *Hope*[3] cases.

Based on the cost of equity estimates indicated by my analyses, I evaluate a fair ROE for LGE/KU, taking into account the specific risks for their jurisdictional utility operations in Kentucky and the Companies' requirements for financial strength, which are properly considered in setting a fair ROE. Further, I corroborate my utility quantitative analyses by applying the DCF model to a group of low risk non-utility firms.

II. RETURN ON EQUITY FOR LGE/KU

Q7. WHAT IS THE PURPOSE OF THIS SECTION?

A7. This section presents my conclusions regarding the fair ROE applicable to LGE/KU's electric and gas utility operations. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Importance of Financial Strength

Q8. WHAT IS THE ROLE OF THE ROE IN SETTING A UTILITY'S RATES?

A8. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a fair and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the

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[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).
[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

U.S. Supreme Court in the *Bluefield* and *Hope* cases. A utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but they can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates, these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (*e.g.,* DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

Q9. THROUGHOUT YOUR TESTIMONY YOU REFER REPEATEDLY TO THE CONCEPTS OF "FINANCIAL STRENGTH," "FINANCIAL INTEGRITY," AND "FINANCIAL FLEXIBILITY." WOULD YOU BRIEFLY DESCRIBE WHAT YOU MEAN BY THESE TERMS?

A9. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the Supreme Court standards. LGE/KU's plans call for a continuation of capital investments in generation, transmission and distribution systems and technology to preserve and enhance service reliability for its customers. The Companies must generate adequate cash flow from operations to fund these requirements and for repayment of maturing debt, together with access to capital from external sources under reasonable terms, on a sustainable basis.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q10. WHAT PART DOES REGULATION PLAY IN ENSURING THAT LGE/KU HAVE ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A10. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's Investors Service ("Moody's") noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[4] Similarly, Standard & Poor's Corporation ("S&P") observed that, "Regulatory advantage is the most heavily

[4] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).

weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[5] The Value Line Investment Survey ("Value Line") summarized these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[6]

Furthermore, the ROE set by the KPSC impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

Q11. DO CUSTOMERS BENEFIT BY ENHANCING THE COMPANIES' FINANCIAL FLEXIBILITY?

A11. Yes. Providing an ROE that is sufficient to maintain LGE/KU's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Recommended ROE

Q12. WHAT IS YOUR RECOMMENDATION AS TO A FAIR RATE OF RETURN ON EQUITY FOR LGE/KU?

A12. I recommend an ROE of 10.42% for LGE/KU's utility operations. The bases for my conclusion are summarized below:

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[5] S&P Global Ratings, "Assessing U.S. Investors-Owned Utility Regulatory Environments," *RatingsExpress* (Aug. 10, 2016).
[6] Value Line Investment Survey, Water Utility Industry (January 13, 2017) at p. 1780.

- In order to reflect the risks and prospects associated with LGE/KU's jurisdictional utility operations, my analyses focused on a proxy group of twenty-one other utilities with both electric and gas operations ("Utility Group").
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, ECAPM, and risk premium methods to estimate a fair ROE for LGE/KU, as well as referencing the expected earnings approach.
- As summarized on Exhibit No. 2, considering the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy group of utilities is in the 9.8% to 10.8% range.
- Adding a flotation cost adjustment of 12 basis points to this bare bones cost of equity range resulted in an ROE range for the proxy group of 9.92% to 10.92%;
- An ROE of 10.42% is equal to the midpoint of the proxy group range.
- Considering capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, an ROE of 10.42% at the midpoint of the proxy group range represents a fair ROE for LGE/KU.

Q13. WHAT ELSE SHOULD BE CONSIDERED IN WEIGHING YOUR QUANTITATIVE RESULTS?

A13. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets, and are not representative of what is likely to prevail over the near-term future. As a result, the DCF results for utilities may be affected by potentially unrepresentative financial inputs. In this light, it is important to consider alternatives to the DCF model. As shown in Exhibit No. 2, alternative risk premium models (*i.e.*, the CAPM, ECAPM and utility risk premium approaches) produce ROE estimates that generally exceed the DCF results. My expected earnings approach corroborated these outcomes.

Q14. HAVE SUCH ALTERNATIVE ROE METHODS BEEN ACCEPTED BY OTHER REGULATORS?

A14. Yes. In its most recent ROE decision in Opinion No. 551, FERC reiterated its support for several of the very same methodologies relied on in my testimony. For example, FERC determined:

> For the reasons discussed below, we conclude that the record in this proceeding demonstrates the presence of unusual capital market conditions, such that we have less confidence that the central tendency of the DCF zone of reasonableness (the midpoint in this case) accurately reflects the equity returns necessary to meet *Hope* and *Bluefield*.[7]

> Rather, that finding supports a consideration of other cost of equity estimation methodologies in determining whether mechanically setting the ROE at the central tendency satisfies the capital attraction standards of *Hope* and *Bluefield*.[8]

> We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies and state-commission approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.[9]

The "alternative methodologies" referred to above include the CAPM, utility risk premium, and expected earnings approaches summarized on Exhibit No. 2. After considering the results of these methods, FERC established an ROE for electric transmission services at the middle of the upper half of the DCF range, or 10.32%.[10]

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[7] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 119 (2016).
[8] *Id.* at P 120.
[9] *Id.* at P 122.
[10] *Id.* at P 9.

Q15. WHAT DID THE DCF RESULTS FOR YOUR SELECT GROUP OF NON-UTILITY FIRMS INDICATE WITH RESPECT TO YOUR EVALUATION?

A15. Average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 9.9% to 11.0% and averaged 10.5% before consideration of flotation costs. While I did not base my recommendation on these results, they confirm that a 10.42% ROE falls in a reasonable range to maintain LGE/KU's financial integrity, provide a return commensurate with investments of comparable risk, and support the Companies' ability to attract capital.

Q16. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANIES' CAPITAL STRUCTURE?

A16. As explained more fully later in my testimony, I concluded that a common equity ratio of 52.84% represents a reasonable basis from which to calculate an overall rate of return for LGE and KU. This conclusion was based on the following findings:

- LGE/KU's common equity ratio is well within the range of capitalizations maintained by the firms in the proxy group of utilities and is consistent with the capitalization maintained by other electric utility operating companies based on data at year-end 2017 and near-term expectations; and,
- The requested capitalization reflects the need to support the credit standing and financial flexibility of LGE/KU as the Companies seek to fund system investments and meet the requirements of customers.

C. Other Factors

Q17. ARE THERE REGULATORY MECHANISMS THAT AFFECT LGE/KU'S RATES FOR UTILITY SERVICE?

A17. Yes. Kentucky Revised Statute 278.183 notes, in part, that "… a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal …" Consistent with this statutory provision, the KPSC has approved an environmental cost recovery mechanism ("ECR") for the Companies that allows for recovery of related costs. LGE and KU also operate under a Demand Side Management ("DSM") rate mechanism that provides for recovery of DSM costs – including a provision to earn a return of and on capital investment for DSM programs. In addition, LGE utilizes a KPSC-approved weather normalization adjustment ("WNA") that partially adjusts natural gas utility revenues for the effect of weather extremes by accounting for differences in consumption due to deviations from normal weather patterns during the heating season months of November through April. The KPSC has also approved a gas line tracker mechanism for LGE that allows for recovery of costs associated with gas main replacement and other infrastructure improvements.

Q18. DOES THE FACT THAT LGE/KU OPERATE UNDER CERTAIN REGULATORY MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A18. No. Investors recognize that the Companies are exposed to significant risks associated with the ability to recover rising costs and investment on a timely basis, and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a tool to address these risks, but they do not eliminate them. In addition, investors also recognize that the heightened scrutiny associated with trackers exposes LGE/KU to increased risk for retroactive reviews and disallowances.

While the regulatory mechanisms approved for LGE/KU partially attenuate exposure to attrition in an era of rising costs and investment, this leveling of the playing field only serves to address factors that could otherwise impair the Companies' opportunity to earn its authorized return. Similarly, LGE/KU's election to employ a future test year is supportive of the Companies' financial integrity, but it does not constitute a dramatic change in the investment risk that investors associate with LGE/KU.

Q19. DO THESE MECHANISMS SET LGE/KU APART FROM OTHER FIRMS OPERATING IN THE UTILITY INDUSTRY?

A19. No. Adjustment mechanisms, cost trackers, and reliance on forward-looking test periods have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of regulatory mechanisms.

Q20. HAVE YOU SUMMARIZED THE VARIOUS REGULATORY MECHANISMS AVAILABLE TO THE OTHER FIRMS IN THE UTILITY GROUP?

A20. Yes. Reflective of industry trends, the companies in the Utility Group operate under a variety of regulatory adjustment mechanisms. As summarized on page 1 of Exhibit No. 3, these mechanisms are ubiquitous and wide ranging. For example, twelve of the twenty-one utilities benefit from mechanisms that permit cost recovery of infrastructure investment outside a formal rate proceeding. Many of these utilities operate under revenue decoupling and other mechanisms that insulate the utility from volatility related to fluctuations in sales volumes, as well as the ability to implement periodic rate adjustments to reflect changes in a diverse range of operating and capital costs, including expenditures related to environmental mandates, conservation programs, transmission costs, and storm recovery efforts.

Q21. IS THE USE OF A FUTURE TEST YEAR ALSO A COMMON FEATURE ON THE REGULATORY LANDSCAPE?

A21. Yes. With respect to future test years, a 2015 study by the Edison Electric Institute concluded that "the ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total."[11] With respect to the twenty-one firms in the Utility Group, twenty operate in jurisdictions that allow for the use of a forward-looking test year. LGE/KU's election to utilize a future test year is consistent with state statute and the treatment afforded other utilities operating in Kentucky, and it does not distinguish the Companies from other utilities across the nation.

Q22. WHAT IS YOUR CONCLUSION REGARDING THE IMPACT OF REGULATORY MECHANISMS IN EVALUATING A FAIR ROE FOR LGE/KU?

A22. Investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility industry, and the relative impact is already considered in the data for my proxy group. As a result, any mitigation in risks associated with LGE/KU's ability to attenuate regulatory lag through adjustment mechanisms or election of a future test year is already reflected in the results of the quantitative methods presented in my testimony. The KPSC's adjustment mechanisms and LGE/KU's election to use a future test year act to level the playing field, placing the Companies on equal footing with their industry peers. As a result, no adjustment to the ROE is justified or warranted.

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[11] *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute (Nov. 11, 2015).

Q23. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN EVALUATING A FAIR ROE FOR THE COMPANIES?

A23. Income taxes, like other expenses necessary to provide utility service, are one component of the cost of service. Amendments to the tax code stemming from the Tax Cuts and Jobs Act ("TCJA"),[12] which are reflected in the revenue requirements requested by the Companies in this case, serve to reduce rates for customers, but they also have negative implications for the financial strength of regulated utilities. By lowering the income tax allowance reflected in rates, eliminating the benefits of bonus depreciation, and requiring the eventual refund of excess accumulated deferred income taxes, the TCJA is widely expected to result in impaired cash flow and undermine credit metrics for utilities, such as LGE/KU.

For example, Moody's recently lowered its ratings outlook for 24 utilities from "stable" to "negative," and one utility from "positive" to "stable," due to the potential impact of the TCJA on cash flows and financial integrity.[13] As Moody's observed:

> Investors-owned utilities' rates, revenue and profits are heavily regulated. The rate regulators allow utilities to charge customers based on a cost-plus model, with tax expense being one of the pass-through items. In practice, regulated utilities collect revenues from customers based on book tax expense but typically pay much less tax in cash. Under the new tax regime, utilities will collect less revenue associated with tax expenses and pay out more cash tax, squeezing its cash flows.[14]

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[12] Approved by Congress on December 22, 2017.

[13] Moody's Investors Service, "Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform." *Ratings Action* (Jan. 19, 2018).

[14] Moody's Investor Service, "Tax reform is credit negative for sector, but impact varies by company," *Sector Comment* (Jan. 24, 2018).

Moody's noted that supportive regulatory actions, in the form of timely cost recovery and constructive determinations regarding capital structure and ROE, would be important to stave off deterioration in credit metrics and potential ratings downgrades.[15] Similarly, S&P concluded that the TCJA will likely have negative rating consequences for many rate-regulated utilities:

> The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. . . . Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.[16]

As S&P concluded, "The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses."[17]

Fitch Ratings Inc. ("Fitch") also highlighted its expectation that the TCJA "has negative credit implications for regulated utilities and utility holding companies over the short to medium term."[18] As Fitch concluded, "Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative ratings actions,"[19] and an "[i]increase in authorized equity ratio and/or return on

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[15] *Id.*

[16] S&P Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," *RatingsDirect* (Jan. 24, 2018).

[17] *Id.*

[18] Fitch Ratings Inc., "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector," *Special Report* (Jan. 24, 2018).

[19] *Id.*

equity" would be one tool to support utilities' credit standing.[20] Coupled with the need to undertake significant new capital investment, the implications of the TCJA heighten the importance of supportive regulatory actions in order to maintain utilities' financial integrity and access to capital.

Q24. WHAT IS MOODY'S CURRENT OUTLOOK ON UTILITIES AND THE IMPACTS OF THE TCJA?

A24. On June 18, 2018, Moody's announced that it was changing the utility sector outlook from stable to negative.[21] Moody's stated that:

> The change in outlook primarily reflects a degradation in key financial credit ratios…The change in outlook also reflects uncertainty with respect to the timing and extent of potential changes in regulatory recovery provisions, authorized returns and equity layers or self-help options by individual companies in response to lower cash flow."[22]

Q25. HAVE S&P OR FITCH TAKEN IMMEDIATE ACTIONS TO LOWER THE OUTLOOK OR RATINGS FOR LGE/KU OR OTHER ISSUERS IN THE UTILITY INDUSTRY?

A25. No. Neither agency has announced an industry-wide reappraisal of credit standing; rather, they have indicated that their evaluation will reflect a "wait-and-see" approach, predicated in large part on the regulatory response for individual utilities. As Fitch noted, "If Fitch sees a credible path for credit metrics to be restored commensurate with the existing rating level, no rating actions may be warranted."[23]

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[20] *Id.*

[21] Moody's Investors Service, "Announcement: Moody's changes the US regulated utility sector outlook to negative from stable." (June 18, 2018).

[22] *Id.*

[23] Fitch Ratings Inc., "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector," *Special Report* (Jan. 24, 2018).

III. FUNDAMENTAL ANALYSES

Q26. WHAT IS THE PURPOSE OF THIS SECTION?

A26. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of LGE and KU. In addition, it examines conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Louisville Gas and Electric and Kentucky Utilities Company

Q27. BRIEFLY DESCRIBE LGE AND KU.

A27. Along with LGE, KU is a wholly owned subsidiary of LG&E and KU Energy LLC ("LKE"), which in turn is a wholly owned subsidiary of PPL Corporation ("PPL"). KU is principally engaged in providing regulated electric utility service. In addition to serving approximately 525,000 retail customers in central, southeastern, and western Kentucky, KU also serves a small customer base in Virginia and Tennessee. LGE is principally engaged in providing regulated electric and gas utility service in Louisville and adjacent areas. LGE serves approximately 411,000 electric customers and provides gas service to approximately 326,000 customers.

Although KU and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. The Companies' utility facilities include combined ownership or interests in approximately 8,017 megawatts ("MW") of generating capacity. Coal-fired generating stations account for approximately 64% of LGE/KU's combined generating capacity and produced approximately 85% of the electricity generated by the Companies in 2017. The electric transmission and distribution systems of KU and LGE include approximately 20,600 and 7,100 miles of lines, respectively. In addition, LGE's natural gas utility system includes more than 4,300 miles of distribution mains and nearly 400 miles of transmission pipelines, along with five underground natural gas storage fields with a current working natural gas capacity of approximately 15 Bcf. As of December 31, 2017, LGE and KU had total assets of $6.6 and $8.3 billion, respectively, with annual revenues totaling approximately $1.5 and $1.7 billion.

LGE/KU's retail electric operations are subject to the jurisdiction of the KPSC, with FERC regulating the Companies' interstate transmission and wholesale operations. In addition, KU is subject to regulation by the VSCC and the Tennessee Public Utility Commission.

Q28. HOW ARE FLUCTUATIONS IN THE COMPANIES' OPERATING EXPENSES CAUSED BY VARYING ENERGY MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A28. LGE/KU's retail electric rates in Kentucky contain a fuel adjustment clause ("FAC"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The KPSC also requires that electric utilities, including LGE/KU, file documents relating to fuel procurement and the purchase of power and energy from other utilities.

With respect to LGE's gas utility operations, the gas supply clause ("GSC") allows for adjustment of natural gas rates on a periodic basis for the difference between the actual gas costs and those collected from customers, subject to applicable regulatory review by the KPSC. The GSC provides for quarterly rate adjustments to reflect the expected cost of natural gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of natural gas supply cost from prior quarters are to be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters.

Q29. WHERE DO LGE/KU OBTAIN THE CAPITAL USED TO FINANCE INVESTMENT IN UTILITY PLANT?

A29. As wholly-owned subsidiaries, the Companies' common equity capital is provided through LKE. Ultimately, LKE obtains investor-supplied common equity capital solely from PPL, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by PPL, LGE and KU also issue first mortgage bonds and tax-exempt debt securities in their own name.

Q30. DO THE COMPANIES ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A30. Yes. LGE/KU will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund investment in new facilities. Moody's informed investors that:

> LG&E's 2017-2021 capital expenditure plan is estimated to be $2.7 billion compared to $2.6 billion spent between 2012 and 2016. Of the $2.7 billion planned capital expenditure, approximately $645 million will be related to its environmental investments. The total estimated amount represents about 54% of the company's net book value of property, plant and equipment, which stood at about $5 billion at the end of the second quarter of 2017.[24]
>
> . . .
>
> KU's total capital expenditures over the next five years are estimated to be $2.7 billion, with $789 million related to environmental investments…The total projected capital expenditure represents about

[24] Moody's Investors Service, "Credit Opinion: Louisville Gas & Electric Company.," *Credit Opinion* (Oct. 27, 2017).

> 41% of KU's net book value of property, plant and equipment, which was about $6.6 billion at the end of the second quarter of 2017.[25]

Moody's noted the challenges associated with the Companies' "[h]igh capital expenditure planned over the next five years," and "[h]igh coal concentration in its generation fuel mix."[26]

Standard & Poor's labels the Companies' financial risk as "significant" based on their elevated capital expenditure programs, "leading to negative discretionary cash flows."[27] S&P's base-case ratings scenario is based on "elevated capital spending" of about $1.2 billion annually for LGE/KU through 2019, "mainly for upgrading generation to meet environmental regulations and investment on transmission and distribution infrastructure."[28] Support for LGE/KU's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund its share of these projects in an effective manner.

Q31. WHAT CREDIT RATINGS ARE ASSIGNED TO LGE/KU?

A31. Currently, LGE and KU are assigned corporate credit ratings of A- by S&P, while Moody's has assigned the Companies an issuer rating of A3.

B. Outlook for Capital Costs

Q32. PLEASE SUMMARIZE CURRENT CAPITAL MARKET CONDITIONS.

A32. Current capital market conditions continue to be affected by the Federal Reserve's unprecedented monetary policy actions, which were designed to push interest rates to historically and artificially low levels in an effort to support economic growth and

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[25] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Company.," *Credit Opinion* (Oct. 27, 2017).

[26] Moody's Investors Service, "Credit Opinion: Louisville Gas & Electric Company.," *Credit Opinion* (Oct. 27, 2017); "Credit Opinion: Kentucky Utilities Company.," *Credit Opinion* (Oct. 27, 2017).

[27] S&P Global Ratings, "Summary: Louisville Gas & Electric Co.," *RatingsDirect* (Dec. 27, 2017); "Summary: Kentucky Utilities Co.," *RatingsDirect* (Dec. 27, 2017).

[28] *Id.*

bolster employment. More recently, investors have faced renewed volatility as capital markets have responded to uncertainties regarding the implications of an expanding economy at or near full employment, indications of price pressures and wage gains, coupled with the massive fiscal stimulus under the TCJA. While the underlying bull market in stocks has continued, the underlying risks and volatility have been exacerbated by concerns over the implications of the Trump Administration's tariff policies, which have stoked fears over the potential for an escalating international trade war.

Q33. HAS THE FEDERAL RESERVE NORMALIZED ITS MONETARY POLICIES?

A33. No. The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400-$500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and the Federal Reserve's holdings continue to exceed $4.1 trillion.[29] While affirming its existing policy of reinvesting principal payments from its securities holdings, the Federal Reserve began to implement a gradual balance sheet normalization program in October 2017, subject to caps and an economic outlook in line with current expectations.[30] Considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities, changes to the Federal

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[29] *Factors Affecting Reserve Balances*, H.4.1 (Jun. 20, 2018). https://www.federalreserve.gov/releases/h41/current/.

[30] Currently, the Federal Reserve Open Market Committee has directed a reduction in principal balances associated with maturing Treasury securities of $24 billion per month and a monthly reduction in the balances of mortgage-backed securities of $16 billion per month. *Minutes of the Federal Open Market Committee July 31-August 1, 2018* at129, https://www.federalreserve.gov/monetarypolicy/files/fomcminutes20180801.pdf.

Reserve's policy of reinvestment have significant, but unknown implications for investors.

Similarly, the Federal Reserve's long-anticipated moves to increase the federal funds rate represent a modest step towards implementing the process of monetary policy normalization outlined in its September 17, 2014 press release,[31] but these incremental increases do not result in a fundamental alteration of its accommodative monetary policy. Nor have they removed uncertainty over the trajectory of further interest rate increases or the overhanging implications of the Federal Reserve's enormous holdings of long-term securities.

Q34. HAVE THESE UNCERTAINTIES BEEN RECOGNIZED BY THE INVESTMENT COMMUNITY?

A34. Yes. Early on, a 2015 report from the global investment management firm BlackRock concluded that, "We are in uncharted territory," when it comes to the implications of unwinding the Federal Reserve's balance sheet holdings.[32] Foreshadowing heightened fiscal stimulus associated with passage of the TCJA, the Wall Street Journal observed the potential for "considerable upward pressure on long-term interest rates" if the need to finance higher deficits coincides with a higher supply of Treasury securities as the Federal Reserve unwinds its balance sheet holdings.[33] Zacks Investment Research ("Zacks") noted that "the rising interest rate environment could add to the woes of utility operators, as it will increase the cost of capital, restraining their ability to pay consistent dividends. . . . The Fed has increased the

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[31] Press Release, Fed. Reserve, Policy Normalization Principles and Plans (Sept. 17, 2014), http://www.federalreserve.gov/newsevents/press/monetary/20140917c.htm.

[32] BlackRock, "When the Fed Yields," *BlackRock Investment Institute* (May 2015).

[33] Josh Zumbrun, "Trump's Fiscal Plans, Fed's Asset Unwinding Could Fuel Rate Rise," *The Outlook*, The Wall Street Journal (May 7, 2017).

interest rate three times in the last three quarters, which will raise the cost of capital for the utilities."[34] As The Wall Street Journal concluded:

> [M]arket moves suggest that investors are taking the prospect of a more hawkish Fed seriously, and that could affect investors across the market. Long-term yields may push higher as short-term rates rise and the Fed trims the size of its balance sheet. . . . Utilities stocks tend to get hurt by rising interest rates because they pay out high dividends that look less attractive relative to bonds when yields rise. S&P utilities stocks fell 0.9% over two sessions.[35]

More recently, The Economist noted that:

> Concerns are growing that the Fed might trip up. It has no guiding example of reversing QE and quitting a zero-interest-rate policy. Tax cuts in America complicate the Fed's task. Higher barriers to trade will add to inflation and hurt GDP, but to an extent that is hard to fathom.[36]

As Reuters reported, Wall Street bond guru Jeffrey Gundlach, chief executive of Doubleline Capital, has concluded that "the low rate-low volatility market environment went on for so long that now the unwind will be turbulent and not over in a couple of days."[37] Uncertainties over just how the process of normalizing the Federal Reserve's unprecedented monetary policies will affect capital markets further support the consideration of alternatives to DCF analyses and other ROE benchmarks when evaluating a just and reasonable ROE for LGE/KU.

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[34] Mark Vickery, "Rising Interest Rates Make Life Tough for Utilities," Zacks Investment Research (Sep. 8, 2017).
[35] Ben Eisen, "Investors Appear Ready to Heed More Hawkish Fed," Wall Street Journal (Sep. 22, 2017).
[36] The Economist, "Even stock market bulls are more cautious than at the start of the year," *Buttonwood* (Jul. 12, 2018).
[37] Jennifer Ablan, "Gundlach,: Market unwind will be 'turbulent,' not over in a few days," *Reuters* (Feb. 7, 2018) (internal quotation marks omitted).

Q35. IS THERE EVIDENCE THAT INVESTORS ANTICIPATE SIGNIFICANTLY HIGHER INTEREST RATES IN THE FORESEEABLE FUTURE?

A35. Yes. Investors continue to anticipate that interest rates will increase significantly from present levels. With apprehension surrounding future Federal Reserve actions, uncertainties regarding the impact of TCJA and future fiscal policies, the potential for expanding federal deficits, and world-wide geopolitical exposures, the potential for significant volatility and higher capital costs is clearly evident to investors. In a recent article discussing new Federal Reserve Chairman Jerome Powell's swearing-in speech, the chief economist at JPMorgan Chase & Co. stated that the Federal Reserve is "in a process of raising rates and not close to the finish line."[38] More recently, the chief executive officer of JPMorgan Chase & Co. suggested investors "should be prepared to deal with the benchmark 10-year bond yield at 5 percent or higher."[39]

The June 1, 2018 long-term consensus forecast of economists published in the Blue Chip Financial Forecast ("Blue Chip") anticipates that corporate bond yields will increase approximately 150 basis points between 2018 and 2023.[40] Figure 1 below compares six-month average interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds as of July 2018 with the respective near-term projections from Value Line, IHS Global Insight, Blue Chip, and the Energy Information Administration ("EIA"), which are sources that are highly regarded and widely referenced:

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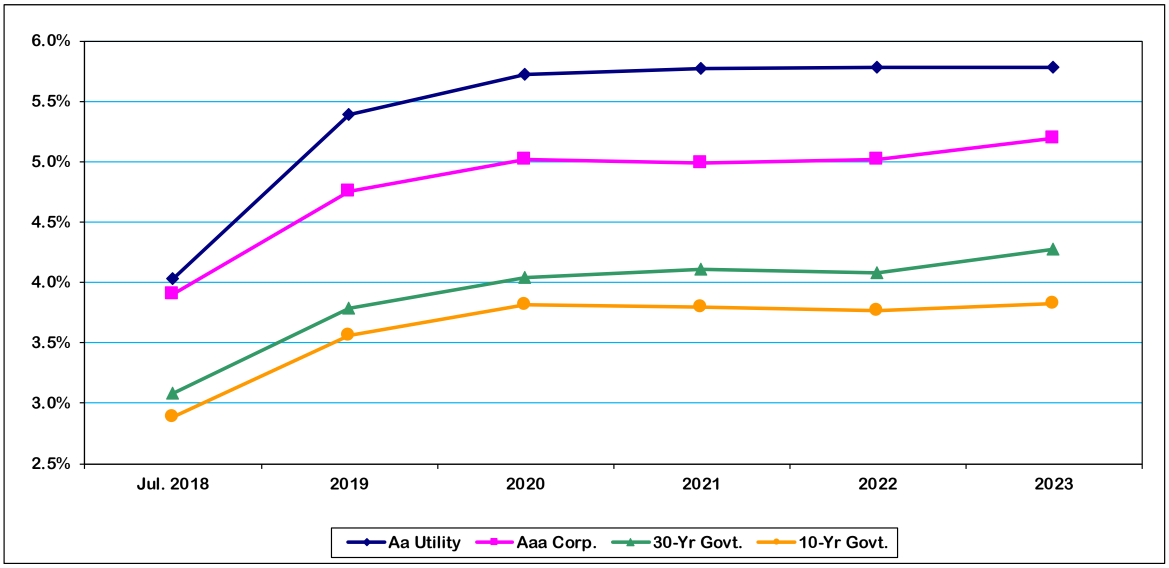
[38] Rich Miller and Christopher Condon, "Powell Suggests Fed to Go Ahead With Rate Hikes Despite Market Turmoil," www.bloomberg.com (Feb. 13, 2018).

[39] Cormac Mullen and Joanna Ossinger, "Bloomberg Markets: Jamie Dimon Warns of 5% Treasury Yields," *Bloomberg* (Aug. 5, 2018).

[40] Wolters Kluwer, *Blue Chip Financial Forecast*, Vol. 37, No. 6 (Jun. 1, 2018).

FIGURE 1
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 1, 2018)
IHS Global Insight (Jun. 6, 2018)
Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018)
Wolters Kluwer, Blue Chip Financial Forecasts, (Jun. 1, 2018)

As evidenced above, projections by investment advisors, forecasting services, and government agencies support the general consensus in the investment community that the present level of long-term interest rates will not be sustained.

Q36. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR LGE/KU MORE GENERALLY?

A36. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets. As a result, current capital costs are not representative of what is likely to prevail over the near-term future and the DCF results for utilities may be affected by potentially unrepresentative financial inputs. As FERC concluded:

> [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

> return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses …[41]

This conclusion continues to be supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated above, recognized economic forecasting services project that long-term capital costs will increase from present levels.

Thus, while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has also recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[42]

In this light, it is important to consider investors' expectations for rising interest rates and capital costs, as well as alternatives to the DCF model, in evaluating the ROE for the Companies.

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[41] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014). FERC confirmed this view in its most recent application of its ROE methodology. Opinion No. 551, 156 FERC ¶ 61,234 (2016).

[42] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

IV. COMPARABLE RISK UTILITY PROXY GROUP

Q37. HOW DID YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR LGE/KU?

A37. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q38. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A38. In order to reflect the risks and prospects associated with LGE/KU's jurisdictional utility operations, my analyses initially focused on a reference group of other utilities composed of those companies in Value Line's electric utility industry groups with:

1. Both electric and gas utility operations.
2. Corporate credit ratings from S&P and Moody's of triple-B or single-A.
3. No ongoing involvement in a major merger or acquisition.[43]
4. No cuts in dividend payments during the past six months and no announcement of a dividend cut since that time.[44]

Q39. WHAT OTHER PUBLICLY TRADED UTILITY IS RELEVANT IN EVALUATING A PROXY GROUP FOR LGE/KU?

A39. Although it has not yet been included in Value Line's electric utility industry groups, investors also regard Algonquin Power & Utilities, Inc. ("Algonquin") as having

[43] Avista Corp., CenterPoint Energy, Dominion Resources, Inc., and Vectren Corp. were eliminated due to ongoing involvement in a major merger or acquisition.
[44] PG&E Corporation was excluded because it eliminated common dividend payments in December 2017.

operations comparable to those of other electric utilities in the proxy group. Algonquin is a North American diversified generation, transmission, and distribution utility with approximately $10 billion in total assets. Algonquin provides regulated utility services to over 782,000 customers in California, Iowa, Illinois, Missouri, Montana, Arkansas, Georgia, and Texas. Algonquin completed its acquisition of Empire District Electric Company ("Empire District") on January 1, 2017. Empire District was included in Value Line's electric utility industry group prior to its merger with Algonquin, and investors would regard Algonquin as a comparable investment alternative that is relevant to an evaluation of the required rate of return for LGE/KU. While Algonquin is not rated by Moody's, it has been assigned a credit rating of BBB by S&P, which falls within the screening criterion identified above.

Q40. IS THERE ANOTHER PUBLICLY TRADED UTILITY THAT IS RELEVANT IN DEVELOPING THE UTILITY GROUP?

A40. In addition to the utilities meeting the criteria outlined above, Emera, Inc. ("Emera") should also be considered in evaluating investors' required rate of return for the Companies. Emera's S&P and Moody's credit ratings fall within the comparable risk bands for the proxy group. The historical stock price and dividend data necessary to apply the DCF approach are available for Emera, as are the consensus earnings per share ("EPS") growth rates from IBES and other comparable sources. Emera is also not engaged in any significant merger transactions that lead to distortion in the inputs to the DCF model.

Headquartered in Halifax, Nova Scotia, Canada, Emera is primarily engaged in electricity generation, transmission, and distribution; gas transmission and distribution; and utility energy services, and serves approximately 2.5 million customers. Emera completed its acquisition of TECO Energy on July 1, 2016. While Emera is currently included in Value Line's "Power Industry" sector, Value Line also reported that as a result of the addition of TECO Energy's regulated utilities in Florida and New Mexico, "the percentage of profits coming from regulated businesses rises to more than 90%."[45]

Similarly, CFRA highlighted Emera's primary focus on electric utility operations, and classified Emera in its "Electric Utilities" industry group,[46] and Emera reports as an "Electric Utility" under the Standard Industrial Classification Code (4911).[47] Thus, investors would regard Emera as a comparable investment alternative that is relevant to an evaluation of the required rate of return for the Companies. Emera's operations are dominated by its U.S.-based utilities in Florida, Maine, and New Mexico, which together accounted for approximately 82% of consolidated net income in 2017.[48]

Applying the criteria outlined above results in a proxy group of twenty-one utilities. I refer to this set of comparable companies as the "Utility Group."

Q41. HOW DID YOU EVALUATE THE RISKS OF THE UTILITY GROUP RELATIVE TO LGE/KU?

A41. My evaluation of relative risk considered four objective, published benchmarks that are widely relied on in the investment community. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes

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[45] The Value Line Investment Survey (Mar. 24, 2017).

[46] CFRA, "Emera Incorporated," *Quantitative Stock Report* (Jun. 24, 2017). CFRA, founded as the Center for Financial Research and Analysis, is one of the world's largest providers of institutional-grade independent equity research, acquired the equity and fund research arm of S&P in October 2016.

[47] *See, e.g.*, Emera, Inc., 2017 SEC Form 40-F. https://www.sec.gov/Archives/edgar/data/1127248/000119312518101807/d555438d40f.htm.

[48] Emera, Inc., 2017 SEC Form 40-F, Exhibit 99.2 at 9.

virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide broad, objective measures of overall investment risk that are readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than

1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[49]

Q42. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE TO LGE/KU?

A42. Table 1 compares the Utility Group with LGE/KU across the four key indices of investment risk discussed above. Because the Companies have no publicly traded common stock, the Value Line risk measures shown reflect those published for their ultimate parent, PPL:

TABLE 1
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Utility Group	BBB+	Baa1	2	A	0.65
LGE/KU	A-	A3	2	B++	0.75

[49] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

Q43. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH YOUR UTILITY GROUP?

A43. As shown above, LGE/KU's credit ratings fall one notch above the average for the utility group, which suggests slightly less risk. Meanwhile, the Safety Rank corresponding to the Companies is identical to the average for the Utility Group, while the Financial Strength Rating and beta value suggest greater risk. Considered together, this comparison of objective measures, which incorporate a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for LGE/KU are comparable to those of the firms in the Utility Group.

Q44. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A44. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of any remaining cash flow.

Q45. WHAT COMMON EQUITY RATIOS ARE USED IN LGE'S AND KU'S CAPITAL STRUCTURES?

A45. The Companies' capital structures are discussed in the testimony of Daniel K. Arbough. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for LGE/KU was 52.84%.

Q46. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY GROUP?

A46. As shown on page 1 of Exhibit No. 4, common equity ratios for the individual firms in the Utility Group ranged from a low of 30.5% to a high of 73.7% at year-end 2017 and averaged 44.3%. Excluding the highest and lowest results, and adjusting this average capitalization to include short-term debt in the same proportions as LGE and KU, would result in adjusted equity ratios of 42.6% and 42.9%, respectively. Meanwhile, Value Line's three-to-five year forecast indicates an average common equity ratio of 46.3% for the Utility Group, with the individual equity ratios ranging from 36.7% to 63.5%.[50]

Q47. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY COMPARABLE UTILITY OPERATING COMPANIES?

A47. Pages 2 and 3 of Exhibit No. 4 displays capital structure data at year-end 2017 for the group of electric utility operating companies owned by the firms in the Utility Group used to estimate the cost of equity.[51] As shown there, common equity ratios for these

[50] Removing the highest and lowest values from Value Line's projections and reflecting the same proportion of short-term debt included in LGE and KU's capitalization would produce adjusted equity ratios of 45.1% and 45.3%, respectively.

[51] I excluded LGE and KU from this analysis.

utilities averaged 52.4%,[52] with 27 of the 55 operating companies having equity ratios equal to or greater than the 52.84% common equity ratio requested by LGE and KU.

Q48. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A48. Utilities are facing significant capital investment plans, the need to accommodate the impact of the TCJA, 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 the need to maintain the continuous access to capital that is required to fund operations and necessary system investment.

In addition, depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating the Companies' financial risk. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. Unless the utility takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken its creditworthiness and imply greater risk.

Q49. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF LGE/KU'S REQUESTED CAPITAL STRUCTURE?

A49. Based on my evaluation, I concluded that the 52.84% common equity ratio requested by LGE/ represents a reasonable mix of capital sources from which to calculate the Companies' overall rate of return. Although this common equity ratio is higher than

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[52] Excluding the highest and lowest results, and adjusting this average capitalization for the electric operating companies to include short-term debt in the same proportion as LGE and KU, would result in adjusted equity ratios of 51.3% and 51.6%, respectively.

the historical and projected averages maintained by the Utility Group, it is well within the range of individual results and consistent with the capitalization maintained by other utility operating companies. 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. The Companies' capital structures reflect the need to support the credit standing and financial flexibility of LGE and KU as they seek to fund system investments and meet the needs of customers.

V. CAPITAL MARKET ESTIMATES

Q50. WHAT IS THE PURPOSE OF THIS SECTION?

A50. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe various quantitative analyses conducted to estimate the cost of common equity for the proxy group of comparable risk firms. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q51. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A51. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q52. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A52. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q53. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A53. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q54. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A54. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q55. DOES THE FACT THAT LGE/KU ARE ULTIMATELY SUBSIDIARIES OF PPL IN ANY WAY ALTER THESE FUNDAMENTAL STANDARDS UNDERLYING A FAIR ROE?

A55. No. While LGE/KU have no publicly traded common stock and PPL is ultimately their only shareholder, this does not change the standards governing the determination of a fair ROE for the Companies. The common equity that is required to support the utility operations of LGE/KU must be raised by PPL in the capital markets, where investors consider the Companies' ability to offer a rate of return that is competitive with other risk-comparable alternatives. Unless there is a reasonable expectation that the Companies can earn a return that is commensurate with the underlying risks, capital will be allocated elsewhere, LGE/KU's financial integrity will be weakened, and investors will demand an even higher rate of return. LGE/KU's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

Q56. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?

A56. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Discounted Cash Flow Analyses

Q57. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A57. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[53]

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[53] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q58. WHAT STEPS ARE REQUIRED TO APPLY THE CONSTANT GROWTH DCF MODEL?

A58. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q59. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITY GROUP?

A59. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Group are presented on page 1 of Exhibit No. 5. As shown there, dividend yields for the firms in the Utility Group ranged from 3.1% to 5.8%.

Q60. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A60. The next step is to evaluate growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q61. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A61. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks and capital requirements in the industry, with the payout ratios falling significantly from historical levels. As a result, dividend growth in the utility industry has lagged growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors' long-term growth expectations are future trends in EPS, which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q62. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A62. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q63. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A63. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[54]

Q64. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A64. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is 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

[54] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

publications, as well as the continued success of services such as Thomson Reuters and Value Line, implies that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. 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 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]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations</u>.[55]

Q65. HAVE REGULATORS ALSO RECOGNIZED THAT ANALYSTS' GROWTH RATE ESTIMATES ARE AN IMPORTANT AND MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A65. Yes. The KPSC has indicated its preference for relying on analysts' projections in establishing investors' expectations:

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[55] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).

> 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…[56]

Similarly, FERC has expressed a clear preference for projected EPS growth rates from IBES in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[57]

The Public Utility Regulatory Authority of Connecticut has also noted that "there is not growth in DPS without growth in EPS," and concluded that securities analysts' growth projections have a greater influence over investors' expectations and stock prices.[58] In addition, the Regulatory Commission of Alaska ("RCA") has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

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[56] *Case No. 2009-00548*, Final Order at 30-31.

[57] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) (footnote omitted).

[58] *Decision*, Docket No. 13-02-20 (Sept. 24, 2013).

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[59]

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[60]

Q66. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY GROUP?

A66. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES, Zacks, Bloomberg L.P. ("Bloomberg"), S&P Capital IQ, and FactSet Research Systems Inc. ("FactSet") are displayed on page 2 of Exhibit No. 5.

Q67. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A67. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of

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[59] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.
[60] Regulatory Commission of Alaska, U-08-157(10) at 36.

the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the Utility Group are summarized on page 2 of Exhibit No. 5, with the underlying details being presented on Exhibit No. 6.[61]

Q68. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A68. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[62] The "sustainable growth" approach was included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q69. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY GROUP USING THE DCF MODEL?

A69. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit No. 5.

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[61] Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach.
[62] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

Q70. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A70. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q71. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A71. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q72. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A72. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. [63] FERC affirmed that:

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[63] *See, e.g., Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

> 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. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[64]

Q73. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR THE UTILITY GROUP?

A73. The average corporate credit ratings for the Utility Group are BBB+ and Baa1 by S&P and Moody's, respectively, which are considered part of the triple-B rating category. Baa utility bonds represent the lowest ratings grade for which Moody's publishes index values, and the closest available approximation for the risks of common stock, which are significantly greater than those of long-term debt. The average of Moody's monthly yields for Baa utility bonds was 4.60% over the six months ended July 2018.[65]

Q74. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A74. As indicated earlier, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes monetary policies. As shown in Table 2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of approximately 6.3% over the period 2019-2023:

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[64] Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).
[65] Moody's Investors Service, *CreditTrends.*

TABLE 2
IMPLIED BBB BOND YIELD

	Baa Yield 2019-23
Projected Aa Utility Yield	
IHS Global Insight (a)	5.37%
EIA (b)	6.01%
Average	5.69%
Current Baa - Aa Yield Spread (c)	0.57%
Implied Baa Utility Yield	**6.26%**

(a) IHS Global Insight (Jun. 6, 2018).
(b) Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Feb. - Jul. 2018.

Q75. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY GROUP?

A75. Adding a 100 basis-point premium to the historical and projected average utility bond yields implies a low-end threshold on the order of 5.6% to 7.3%. As highlighted on page 3 of Exhibit No. 5, after considering this test and the distribution of individual estimates, I eliminated low-end DCF estimates ranging from 2.5% to 6.9%. Based on my professional experience and the risk-return tradeoff principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, consistent with the threshold established by historical and projected utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q76. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A76. While FERC has historically relied on a 100 basis point spread over public utility bond yields as a starting place in evaluating low-end values, reference to a static test ignores the implications of current low bond yields. Specifically, the premium that investors demand to bear the higher risks of common stock is not constant. As I demonstrate later in my testimony, equity risk premiums expand when interest rates fall, and vice versa. Given that bond yields have remained uncharacteristically low, this inverse relationship implies a significant increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. As a result, using a fixed premium of 100 basis points over public utility bond yields will vastly understate the threshold for investors' minimum required return on utility stocks.

Q77. DO YOU ALSO RECOMMEND EXCLUDING ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A77. While it is just as important to evaluate DCF estimates at the upper end of the range, there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values. In response, FERC has consistently applied a two-pronged test for high-end values based on the magnitude of the cost of equity estimate and its underlying growth rate. As FERC observed:

> The Presiding Judge found that the [utilities'] criteria for screening high-end outliers substantially complies with Commission precedent. . . The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[66]

[66] Opinion No. 531, 147 FERC ¶ 61,234 at P 115 (2014)(footnotes omitted).

Based on these principles, I reviewed the DCF results and determined that the 23.0% estimate for Algonquin (FactSet growth rate 17.6%) was unreasonably high and should be removed. Similarly, as shown on page 3 of Exhibit No. 5, I also eliminated an 18.7% value for Emera (Bloomberg growth rate of 13.4%) and an estimate of 19.6% for Sempra Energy (Bloomberg growth rate of 16.3%).

Beyond this, the upper end of the DCF results for the Utility Group is set by a cost of equity estimate of 16.4%. This cost of equity estimate, and the underlying growth rate, falls well below the threshold tests employed by FERC. Moreover, while a 16.4% cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return. This conclusion is consistent with the recent findings of the Presiding Judge in Docket No. EL16-64 before FERC, who concluded that a 16.14% DCF estimate "should not be excluded from any proxy group as a 'high-end outlier.'"[67]

Q78. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY GROUP?

A78. As shown on page 3 of Exhibit No. 5 and summarized in Table 3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following average cost of common equity estimates:

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[67] *Belmont Municipal Light Dept.*, Initial Decision, 162 FERC ¶ 63,026 (2018) at P 212.

TABLE 3
DCF RESULTS – UTILITY GROUP

Growth Rate	Cost of Equity Average	Cost of Equity Midpoint
Value Line	10.5%	11.9%
IBES	9.4%	11.2%
Zacks	9.8%	10.4%
Bloomberg	10.2%	10.7%
S&P Capital/IQ	10.2%	11.9%
FactSet	9.7%	11.8%
br + sv	8.9%	9.9%

C. Capital Asset Pricing Model

Q79. PLEASE DESCRIBE THE CAPM.

A79. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

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 estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q80. WHY IS THE CAPM APPROACH A RELEVANT COMPONENT WHEN EVALUATING THE COST OF EQUITY FOR LGE/KU?

A80. The CAPM approach (which also forms the foundation of the ECAPM) generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks, including LGE/KU.

Q81. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A81. Application of the CAPM to the Utility Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 7. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Zacks, and the growth rate was equal to the average of the earnings growth projections for each firm published by Value Line, IBES and Zacks Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 10.9%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 13.2%.

Subtracting a 3.1% risk-free rate based on the average yield on 30-year Treasury bonds for the six months ending July 2018 produced a market equity risk premium of 10.1%.

Q82. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A82. As indicated earlier in my discussion of risk measure for the Utility Group, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q83. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A83. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between company size and return. … The relationship between company size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks. … This size-rated phenomenon has prompted a revision to the CAPM, which includes a size premium.[68]

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have 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

[68] *Morningstar*, "Ibbotson SBBI 2015 Classic Yearbook," at pp. 99, 108.

capitalization in determining the CAPM cost of equity.[69] Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Utility Group.

Q84. ARE YOU RECOMMENDING THAT THE COMMISSION AWARD LGE/KU A PREMIUM TO THE ROE BECAUSE OF THEIR SIZE?

A84. Absolutely not. I am not proposing to apply a general size risk premium in evaluating a fair and reasonable ROE for LGE/KU and my recommendation does not include any adjustment related to the Companies' size. Rather, the size adjustment is specific to the CAPM and merely corrects for an observed inability of the beta measure to fully reflect the risks perceived by investors for the firms in the Utility Group. As FERC has recognized, "This type of size adjustment is a generally accepted approach to CAPM analyses."[70]

Q85. WHAT IS THE IMPLIED ROE FOR THE UTILITY GROUP USING THE CAPM APPROACH?

A85. As shown on page 1 of Exhibit No. 7, after adjusting for the impact of firm size, the CAPM approach implied an average cost of equity of 10.1% for the Utility Group, with a midpoint cost of equity estimate of 10.4%.

Q86. DID YOU ALSO APPLY THE CAPM USING FORECASTED BOND YIELDS?

A86. Yes. As discussed earlier, there is general consensus that interest rates will increase materially as the Federal Reserve normalizes its monetary policies going forward. Accordingly, in addition to the use of current bond yields, I applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections

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[69] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, "Stocks, Bonds, Bills and Inflation," these size premia are now developed by Duff & Phelps and presented in its "Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples," (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

[70] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).

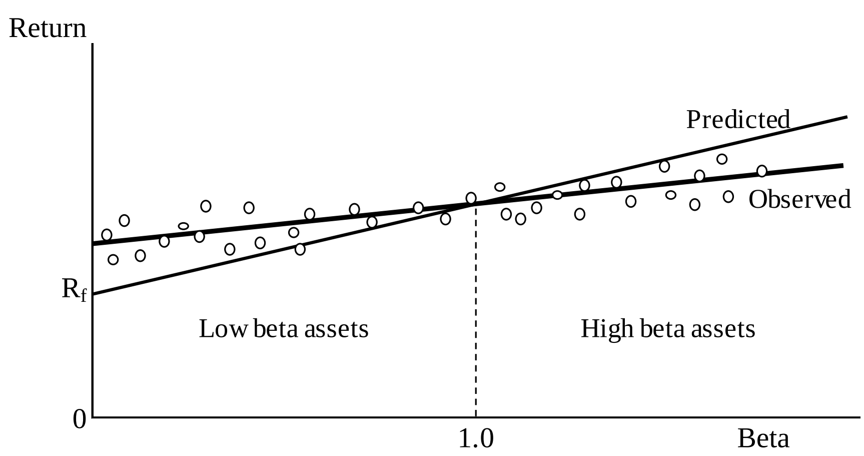
published by Value Line, IHS Global Insight, and Blue Chip. As shown on page 2 of Exhibit No. 7, incorporating a forecasted Treasury bond yield for 2019-2023 implied an average cost of equity estimate of 10.4% for the Utility Group after adjusting for the impact of relative size, with a midpoint of 10.7%.

D. Empirical Capital Asset Pricing Model

Q87. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A87. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE 2
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the Utility Group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[71]

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk premium ($R_m - R_f$) weighted by a factor of 25%, and (2) a company-specific risk premium based on the stocks relative volatility $[(\beta)(R_m - R_f)]$ weighted by 75%. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

[71] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

Q88. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF VALUE LINE BETAS?

A88. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[72] The purpose of this adjustment is to refine beta values determined using historical data to better match forward-looking estimates of beta, which are the relevant parameter in applying the CAPM or ECAPM models. Meanwhile, the ECAPM does not involve any adjustment to beta whatsoever. Rather, it represents a formal recognition of findings in the financial literature that the observed risk-return tradeoff illustrated in Figure 2 is flatter than predicted by the CAPM. In other words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns.

Q89. HAVE OTHER REGULATORS RELIED ON THE ECAPM?

A89. Yes. The ECAPM approach has been relied on by the Staff of the Maryland Public Service Commission. For example, Staff witness Julie McKenna noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[73] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The

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[72] *See, e.g.*, Marshall E. Blume, "Betas and Their Regression Tendencies," *Journal of Finance*, Vo. 30, No. 3 (Jun. 1975) at 785-795.

[73] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at 9.

> reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[74]

The staff of the Colorado Public Utilities Commission has also recognized that, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[75] and relied on the exact same standard ECAPM equation presented above.[76] The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility, as have witnesses for the Office of Arkansas Attorney General.[77]

Q90. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE ECAPM?

A90. My applications of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connection with the CAPM. As shown on page 1 of Exhibit No. 8, applying the forward-looking ECAPM approach to the firms in the Utility Group results in an average unadjusted cost of equity estimate of 11.0% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities. The midpoint of the size adjusted ECAPM range is 11.3%.

As shown on page 2 of Exhibit No. 8, incorporating a forecasted Treasury bond yield for 2019-2023 implied an average cost of equity for the Utility Group of 11.2%, after adjusting for the impact of relative size. The midpoint of the size adjusted ECAPM range is 11.6%.

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[74] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.
[75] Proceeding No. 13AL-0067G, *Answer Testimony and Exhibits of Scott England* (July 31, 2013) at 47.
[76] *Id.* at 48.
[77] Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53; Docket No. 17-071-U, *Direct Testimony of Marlon F. Griffing, PH.D.* (May 29, 2018) at 33-35.

E. Utility Risk Premium

Q91. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A91. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q92. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A92. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for LGE/KU.

Q93. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A93. Estimates of equity risk premiums for utilities were based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q94. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR LGE/KU?

A94. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices dividends, beta, and interest rates) and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q95. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A95. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. 9, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2017.[78] As shown on page 3 of Exhibit No. 9, over this period, these equity risk premiums for electric utilities averaged 3.71%, and the yield on public utility bonds averaged 8.28%.

Q96. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A96. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that

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[78] My analysis encompasses the entire period for which published data is available.

the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1%. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

As noted earlier, bond yields are at low levels. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q97. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A97. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[79] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[80]

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[79] *See, e.g.*, E. F. Brigham, D. K. Shome, and S. R.Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); R. S. Harris and F. C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

[80] Roger A. Morin, "New Regulatory Finance," Public Utilities Reports, at 128 (2006).

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates, these variables do not move in lock-step because of the inverse relationship between equity risk premiums and interest rates.[81] This relationship is illustrated in the figure on page 4 of Exhibit No. 9.

Q98. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A98. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. 9, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 9, with an average yield on public utility bonds for the six-months ending July 2018 of 4.28%, this implied a current equity risk premium of 5.44% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 4.60% implies a current cost of equity of 10.04%.

Q99. WHAT RISK PREMIUM COST OF EQUITY ESTIMATE WAS PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A99. As shown on page 2 of Exhibit No. 9, incorporating a forecasted yield for 2019-2023 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.72% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2019-2023 of 6.26% resulted in an implied cost of equity of 10.98%.

Q100. THE EQUITY RISK PREMIUMS CALCULATED IN YOUR STUDY WERE BASED ON AUTHORIZED ROES PUBLISHED BY RRA. WOULD IT NOT

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[81] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf; *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

BE EQUALLY APPROPRIATE TO USE RECENT VALUES COMPILED BY RRA TO ESTABLISH LGE/KU'S ROE DIRECTLY?

A100. No, it would not. While data on allowed returns published by RRA can have a role in evaluating a fair and reasonable ROE, there is no basis to place undue weight on a single, summary statistic in lieu of comprehensive analyses and a case-specific evidentiary record. Most importantly, such an approach fails to satisfy the standards mandated by the U.S. Supreme Court in its *Bluefield* and *Hope* decisions, which dictate that the ROE reflect contemporaneous returns to investments of comparable risk.

These bedrock opinions require regulators to consider the individual and specific risks and financial circumstances facing the utility, as well as the capital market conditions and investor expectations concurrent with their deliberations. Meeting these standards necessitates detailed analyses and the application of financial models and approaches with inputs that are specific to the utility in question. In context of a rate case, alternative analyses and expert opinions are subject to thorough discovery and cross examination from all stakeholders, with the results being carefully weighed by regulators to arrive at their best estimate of the cost of equity. Developing the evidentiary record necessary to satisfy the *Hope* and *Bluefield* tests is a rigorous process that cannot be reduced to an isolated summary statistic from an industry publication such as RRA.

Q101. PLEASE ELABORATE ON WHY A RECENT AVERAGE ROE REPORTED BY RRA FALLS SHORT OF ACCEPTED REGULATORY STANDARDS.

A101. Setting a utility's ROE is a very company-specific process and is a function of investors' perceptions of the risks and prospects for the subject company at a given point in time. Meanwhile, quarterly allowed ROEs reported by RRA are not necessarily representative or directly comparable to the utility at hand. That is, there may be an "apples and oranges" issue when the RRA data is applied in the current rate setting environment.

For instance, there can be significant differences in investment risks (*e.g.*, credit ratings) between the utilities that are the subject of a specific quarterly average ROE reported by RRA and the subject company in a rate proceeding, functional differences (integrated utilities versus "wires only" distribution services), as well as other utility-specific characteristics (*e.g.* size differences, capital requirements, and economic conditions in the service territory). Finally, capital market conditions during the evidentiary record that support the decisions reported by RRA are not likely to be identical to those prevailing during a subsequent rate proceeding. The very nature of RRA's quarterly publication schedule ensures that there will always be a lag between the results it reports and the ongoing case under study. All of these differences can lead to a potential disconnect between the broad summary statistics reported by RRA and the comprehensive and detailed analyses required to meet the *Hope* and *Bluefield* standards.

Q102. DON'T THESE SAME CONCERNS EQUALLY AFFECT YOUR USE OF THE RRA-REPORTED AUTHORIZED ROES TO CALCULATE YOUR RISK PREMIUM COST OF EQUITY ESTIMATE?

A102. No. My risk premium study considers all reported data concerning allowed ROEs over a forty-four year horizon. As a result, it incorporates findings that reflect regulators' broad assessment of the required rate of return for the electric utility industry in general and is not unduly influenced by the specific risks or circumstances of a small subset of the industry that make up an isolated statistic based on decision in a particular calendar quarter. In addition, my application of the risk premium approach based on allowed ROEs from RRA specifically accounts for the impact of changes in capital market conditions by adjusting for the observed inverse relationship between equity risk premiums and interest rates, and by incorporating current bond yields when calculating the implied cost of equity.

Q103. COULD THE PROCESS BECOME CIRCULAR IF STATE REGULATORS WERE TO ROUTINELY ACCEPT ROE RESULTS FROM OTHER STATES AS THE BASIS TO SET A UTILITY'S RETURN?

A103. Yes. As noted above, the standard practice in regulatory proceedings is to consider the results of numerous approaches that are grounded in current capital market evidence when establishing a utility's ROE. If, instead, regulators were to simply rely on the most recent determinations of other state agencies, the connection between regulatory findings and investors in the capital markets would soon be broken.[82] For this reason, state regulatory agencies are charged with the responsibility of independently evaluating detailed evidence to establish an ROE corresponding to the specific risks, capital market conditions, and investor expectations facing the utility under its jurisdiction. This is precisely the standard dictated by the *Hope* and *Bluefield* decisions.

Q104. ARE YOU SAYING THERE IS NO PLACE FOR RRA DATA IN THIS PROCESS?

A104. No. As discussed earlier, I use such data in my risk premium approach as an input to calculate annual average historical risk premiums, which are then adjusted to account for current capital market conditions and specific risk differences. Using this method, allowed ROE data from RRA is one of a number of inputs in a comprehensive, multi-year study that ultimately leads to a cost of equity estimate specific to the utility at hand and steeped in both investor expectations and financial theory.

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[82] While RRA data may be one factor considered by investors in developing their expectations, the required return is a function of the underlying risks associated with the utility at issue and the other investment opportunities available in the capital markets, including non-utility firms.

It is also common to reference allowed ROEs reported by RRA as a benchmark or guidepost when assessing the reasonableness of cost of equity estimates derived from primary methodologies, such as the DCF and CAPM. In other words, RRA data is valuable as a "secondary" approach, useful in judging whether an ROE estimate based on the application of accepted financial models makes sense "on its face." In the right context, allowed ROE data from RRA can contribute in a valuable supporting role as part of the ROE estimation process.

F. Expected Earnings Approach

Q105. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A105. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q106. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A106. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. Such an outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q107. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A107. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices – both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings 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.

Q108. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR LGE/KU BASED ON THE EXPECTED EARNINGS APPROACH?

A108. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.75% over its 2021-2023 forecast horizon.[83] Meanwhile, for the firms in the Utility Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit No. 10. As I explained earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[84] Accordingly, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit No. 7. As shown on Exhibit No. 10, Value Line's projections for the Utility Group suggest an average ROE of approximately 11.1%, with a midpoint value of 11.3%.

G. Flotation Costs

Q109. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A109. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out

[83] The Value Line Investment Survey (May 18, Jun. 15, Jun. 22, & Jul. 27, 2018). Recall that Value Line reports return on year-end equity so the equivalent return on average equity would be higher.

[84] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity. While LGE/KU have no publicly traded stock and do not incur flotation costs directly, equity capital is provided by investors through PPL's sale of common shares. Thus, these expenses are also relevant when evaluating the fair and reasonable ROE for a wholly-owned subsidiary, such as the Companies.

Q110. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A110. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q111. THE KPSC HAS NOT ROUTINELY APPROVED A FLOTATION COST ADJUSTMENT FOR LGE/KU. WHY DO YOU CONTINUE TO RECOMMEND AN ADJUSTMENT IN THIS CASE?

A111. I am aware that the KPSC has not routinely approved a flotation cost adjustment for LGE/KU in past proceedings. Nevertheless, the financial literature and evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for the Companies. An adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[85] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[86]

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[85] E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.
[86] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

Q112. CAN YOU ILLUSTRATE WHY INVESTORS WILL NOT HAVE THE OPPORTUNITY TO EARN THEIR REQUIRED ROE UNLESS A FLOTATION COST ADJUSTMENT IS INCLUDED?

A112. Yes. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 10.5%, the expected dividend in year 1 is $0.50 (i.e., a dividend yield of 5%), and that growth is expected to be 5.5% annually. As developed in Table 4 below, if the allowed rate of return on common equity is only equal to the utility's 10.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 5.25%, instead of 5.5%:

TABLE 4
NO FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.50%	$ 1.00	$ 0.50	50.0%
2	$ 9.52	$ 0.50	$ 10.02	$10.52	1.050	10.50%	$ 1.05	$ 0.53	50.0%
3	$ 9.52	$ 0.53	$ 10.55	$11.08	1.050	10.50%	$ 1.11	$ 0.55	50.0%
Growth			**5.25%**	**5.25%**			**5.25%**	**5.25%**	

The reason that investors never really earn 10.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Including a flotation cost adjustment allows investors to be fully compensated for the impact of these costs. One commonly referenced method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown in Table 5 below, by allowing a rate of return on common equity of 10.75% (an 10.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 10.5% required rate of return, since actual growth is now equal to 5.5%:

TABLE 5
INCLUDING FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.75%	$ 1.02	$ 0.50	48.9%
2	$ 9.52	$ 0.52	$ 10.04	$10.55	1.050	10.75%	$ 1.08	$ 0.53	48.9%
3	$ 9.52	$ 0.55	$ 10.60	$11.13	1.050	10.75%	$ 1.14	$ 0.56	48.9%
Growth			**5.50%**	**5.50%**			**5.50%**	**5.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q113. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A113. The most common method used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. In Exhibit No. 11, I have gathered data on the most recent open-market common stock issues for each company in Value Line's electric utility industry. For all companies in the electric industry, flotation costs averaged 3.1%. Applying this 3.1% expense percentage to the Utility Group dividend yield of 4.00% produces a flotation cost adjustment on the order of 12 basis points. I thus recommend the Commission increase the cost of equity by 12 basis points in arriving at a fair and reasonable ROE for LGE/KU.

Q114. HAVE OTHER REGULATORS RECOGNIZED FLOTATION COSTS IN EVALUATING A FAIR AND REASONABLE ROE?

A114. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[87]

More recently, in Case No. INT-G-16-02 the staff of the Idaho Public Utilities Commission supported the use of the same flotation cost methodology that I recommend above, concluding:

> [I]s the standard equation for flotation cost adjustments and is referred to as the "conventional" approach. Its use in regulatory proceedings is widespread, and the formula is outlined in several corporate finance textbooks.[88]

Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[89] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider formula.[90] The

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[87] *Third Supplemental Order*, WUTC Docket No. UE-991606, *et al.* (September 2000) at 95.
[88] Case No. INT-G-16-02, *Direct Testimony of Mark Rogers* (Dec. 16, 2016) at 18.
[89] *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).
[90] *See*, *e.g.*, Entergy Mississippi, Inc., Formula Rate Plan Rider (Apr. 15, 2015), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf (last visited Mar. 16, 2017).

Public Utilities Regulatory Authority of Connecticut[91] and the Minnesota Public Utilities Commission[92] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair and reasonable ROE.

VI. NON-UTILITY BENCHMARK

Q115. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A115. This section presents the results of my DCF analysis applied to a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis was not directly considered in arriving at my recommended ROE range of reasonableness; however, it is my opinion that this is relevant consideration in evaluating a fair ROE for the Companies.

Q116. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A116. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

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[91] *See, e.g.*, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.

[92] *See, e.g.*, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9 (2011).

Q117. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A117. Yes. The cost of equity capital 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 it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[93]

As in *Bluefield*, there is nothing to restrict "other enterprises" to the utility industry.

Q118. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP HELP TO IMPROVE THE RELIABILITY OF DCF RESULTS?

A118. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low-risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q119. HOW DID YOU DEVELOP THE NON-UTILITY GROUP?

A119. My low-risk group of competitive firms was composed of those U.S. companies followed by Value Line that:

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[93] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

(1) pay common dividends;
(2) have a Safety Rank of “1”;
(3) have a Financial Strength Rating of “A” or greater;
(4) have a beta of 0.75 or less; and
(5) have investment grade credit ratings from S&P and Moody’s.[94]

Q120. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY GROUP?

A120. Table 6 compares the Non-Utility Group with the Utility Group and LGE/KU across the four key risk measures discussed earlier:

TABLE 6
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A-	A3	1	A+	0.74
Utility Group	BBB+	Baa1	2	A	0.65
LGE/KU	A-	A3	2	B++	0.75

When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Utility Group and LGE/KU are greater than those of the firms in the Non-Utility Group.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Procter & Gamble, and Walmart, have long corporate histories, well-

[94] Credit rating firms, such as S&P, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term “investment grade” refers to bonds with ratings in the ‘BBB’ category and above.

established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group of approximately 3.5%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q121. DO THE BETA VALUES FOR THE NON-UTILITY GROUP ADDRESS THE CONCERNS EXPRESSED BY THE KPSC IN A PRIOR RATE PROCEEDING?

A121. Yes. The KPSC concluded in Case No. 2009-00548 that utilities must compete with non-regulated firms for capital and recognized that investors consider the opportunity costs associated with investment alternatives outside the utility industry. However, the KPSC found that lower beta values for utility common stocks supported a finding that the non-utility companies were "riskier alternatives."[95] My proxy group criteria restricted the Non-Utility Group to include only firms with beta values of 0.75 or less, with the group's average beta of 0.74 being slightly lower than the 0.75 value corresponding to LGE/KU.

Q122. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A122. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group, with the results being presented in Exhibit No. 12. As summarized in Table 7, below, application of the constant growth DCF model resulted in the following cost of equity estimates:

---

[95] *Case No. 2009-00548*, Final Order at 31.

TABLE 7
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.9%	11.1%
IBES	9.9%	9.9%
Zacks	10.5%	10.4%
Bloomberg	10.4%	9.8%
S&P Capital/IQ	11.0%	11.3%
FactSet	10.5%	9.7%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for LGE/KU.

Q123. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A123. Yes.

VERIFICATION

STATE OF Texas)
) **SS:**
COUNTY OF Travis)

The undersigned, **Adrien M. McKenzie**, 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.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of September 2018.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

EXHIBIT NO. 1

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River St., Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 100 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Montana, Nebraska, New Mexico, Ohio, Oregon, South Dakota, Virginia, Washington, West Virginia, and Wyoming.[1] My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute and the CFA Society of Austin. A resume containing the details of my qualifications and experience is attached below.

[1] Over the course of my career, I have supported the preparation of prefiled testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states. This testimony was sponsored by Dr. William Avera, who was formerly President of FINCAP, Inc.

ADRIEN M. McKENZIE

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River Street
Austin, Texas 78751
(512) 923-2790
FAX (512) 458–4768
amm.fincap@outlook.com

Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President
FINCAP, Inc.
(June 1984 to June 1987)
(April 1988 to present)

Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.

Manager,
McKenzie Energy Company
(Jan. 1981 to May. 1984)

Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in over thirty state jurisdictions, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

SUMMARY OF RESULTS

	Average		Midpoint
DCF			
Value Line	10.5%		11.9%
IBES	9.4%		11.2%
Zacks	9.8%		10.4%
Bloomberg	10.2%		10.7%
S&P Capital/IQ	10.2%		11.9%
FactSet	9.7%		11.8%
Internal br + sv	8.9%		9.9%
CAPM			
Current Bond Yield	10.1%		10.4%
Projected Bond Yield	10.4%		10.7%
Empirical CAPM			
Current Bond Yield	11.0%		11.3%
Projected Bond Yield	11.2%		11.6%
Utility Risk Premium			
Current Bond Yield		10.0%	
Projected Bond Yields		11.0%	
Expected Earnings			
Industry		10.8%	
Proxy Group	11.1%		11.3%

ROE Recommendation			
Recommended Cost of Equity Range	**9.8%**	**--**	**10.8%**
Flotation Cost Adjustment			
Dividend Yield		4.00%	
Flotation Cost Percentage		3.10%	
Adjustment		0.12%	
Recommended ROE			
Range	**9.92%**	**--**	**10.92%**
Midpoint		**10.42%**	

REGULATORY MECHANISMS

UTILITY GROUP

		Type of Adjustment Clause										
				Decoupling				New Capital				
	Holding Company	Elec. Fuel/ Purch. Pwr	Conserv. Program Expense	Full	Partial	Renew- ables Expense	Environ- mental Compliance	Gener- ation Capacity	Generic Infra- structure	Trans- mission Expense	Other	Future Test Year
1	Algonquin Pwr & Util	√	- -	- -	√	- -	√	- -	√	√	Taxes, franchise fees; renewables mechanism available	P
2	Alliant Energy	√	- -	- -	√	- -	√	- -	√	√	Taxes, franchise fees; renewables mechanism available	P
3	Ameren Corp.	√	- -	- -	√	- -	√	- -	√	√	Taxes, franchise fees; renewables mechanism available	P
4	Avangrid, Inc.	D	√	√	- -	√	- -	D	- -	- -	Storm costs	C
5	Black Hills Corp.	√	√	- -	√	√	√	√	√	√		O
6	CMS Energy Corp.	√	√	- -	- -	√	- -	- -	- -	√		C
7	Consolidated Edison	D	- -	√	- -	√	- -	D	- -	- -		C
8	DTE Energy Co.	√	√	- -	- -	√	- -	- -	- -	√		C
9	Duke Energy Corp.	√	√	- -	√	√	√	√	√	√	Taxes, franchise fees, bad debts, storm costs	C,O,P
10	Emera Inc.	√	√	- -	- -	- -	√	√	- -	- -	Taxes, franchise fees	C
11	Entergy Corp.	√	√	- -	√	- -	√	√	√	√	Taxes, franchise fees, storm costs	O,P
12	Eversource Energy	√	√	√	- -	√	- -	- -	√	√		C
13	Exelon Corp.	D	√	√	√	√	√	D	√	√	Taxes, franchise fees, bad debts, nuclear decomm., societal benefits	O,P
14	Fortis Inc.	D	√	- -	√	√	√	D	√	√	Franchise fees	C
15	NorthWestern Corp.	√	√	- -	- -	- -	- -	- -	- -	- -	Purchased power contracts	- -
16	PPL Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, universal service program costs	O
17	Public Service Enterprise Group	D	√	- -	- -	√	√	D	√	- -	Taxes, franchise fees, societal benefits	P
18	Sempra Energy	√	- -	√	- -	- -	- -	- -	- -	- -		C
19	Southern Company	√	√	- -	√	- -	√	√	- -	- -	Taxes, franchise fees, storm costs	C,O
20	WEC Energy Group	√	- -	- -	- -	- -	- -	- -	- -	- -	Taxes, franchise fees	C
21	Xcel Energy Inc.	√	√	√	- -	√	√	√	√	√	Taxes, franchise fees, university discounts	C

Sources:

Exhibit No. 3, pages 2-4, contain operating company data that are aggregated into the parent company data on this page.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

UTILITY GROUP ELECTRIC OPERATING COS.

Holding Company/ Operating Company	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
ALGONQUIN PWR & UTIL												
Empire District Electric	MO	√	- -	- -	- -	- -	√	- -	- -	√	√	P
Liberty Utilities	NH	D	- -	- -	√	- -	- -	D	√	- -	- -	- -
ALLIANT ENERGY CORP.												
Interstate Power & Light	IA	√	√	- -	- -	√	√	- -	- -	√	√	- -
Wisconsin Power & Light	WI	√	- -	- -	- -	- -	- -	LIR	LIR	- -	√	C
AMEREN												
Ameren Illinois	IL	D	√	- -	- -	√	√	D	- -	√	√	O
Union Electric	MO	√	√	- -	√	- -	√	- -	√	√	√	P
AVANGRID												
Central Maine Pwr	ME	D	- -	√	- -	- -	- -	D	- -	- -	√	C
NY State E&G	NY	D	- -	√	- -	√	- -	D	- -	- -	- -	C
Rochester G&E	NY	D	- -	√	- -	√	- -	D	- -	- -	- -	C
United Illuminating	CT	D	√	√	- -	- -	- -	D	- -	√	- -	C
BLACK HILLS CORP.												
BH Power	SD	√	√	- -	√	- -	√	- -	- -	√	√	- -
Cheyenne Light	WY	√	√	- -	√	√	- -	- -	- -	- -	√	O
BH Colorado Elec	CO	√	√	- -	- -	√	- -	√	√	- -	√	- -
CMS ENERGY												
Consumers Energy	MI	√	√	- -	- -	√	- -	- -	- -	√	- -	C
CONSOLIDATED EDISON												
Consolidated Edison of NY	NY	D	- -	√	- -	√	- -	D	- -	- -	- -	C
Orange & Rockland	NY	D	- -	√	- -	√	- -	D	- -	- -	- -	C
DTE ENERGY												
DTE Electric	MI	√	√	- -	- -	√	- -	- -	- -	√	- -	C
DUKE ENERGY												
Duke Energy Carolinas	NC	√	√	- -	- -	√	√	- -	- -	- -	- -	- -
Duke Energy Florida	FL	√	√	- -	- -	- -	√	√	- -	- -	√	C
Duke Energy Indiana	IN	√	√	- -	√	√	√	√	√	√	√	- -
Duke Energy Ohio	KY	√	√	- -	√	√	- -	- -	- -	- -	√	O
Duke Energy Progress	OH	D	√	- -	√	√	- -	D	√	√	√	P
Progress Energy Inc.	SC	√	- -	- -	- -	- -	√	- -	- -	- -	- -	- -

UTILITY GROUP ELECTRIC OPERATING COS.

		Type of Adjustment Clause (a)										
				Decoupling				New Capital				
Holding Company/ Operating Company	**State**	**Elec. Fuel/ Gas/ Purch. Pwr**	**Conserv. Program Expense**	**Full**	**Partial**	**Renew-ables Expense**	**Environ-mental Compliance**	**Gener-ation Capacity**	**Generic Infra-structure**	**Trans-mission Expense**	**Other**	**Future Test Year (b)**
EMERA INC.												
Emera Maine	ME	D	- -	- -	- -	- -	- -	- -	- -	- -	- -	C
Tampa Electric Co.	FL	√	√	- -	- -	- -	√	√	- -	- -	√	C
ENTERGY CORP.												
Entergy Arkansas Inc.	AR	√	√	- -	√	- -	- -	√	√	√	√	P
Entergy Louisiana LLC	LA	√	√	- -	√	- -	√	√	- -	√	√	O
Entergy Mississippi Inc.	MS	√	√	- -	√	- -	√	- -	- -	√	√	O
Entergy New Orleans Inc.	LA	√	√	- -	√	- -	√	√	- -	√	√	O
Entergy Texas Inc.	TX	√	√	- -	- -	- -	- -	- -	√	√	√	- -
EVERSOURCE ENERGY												
Connecticut Light & Power	CT	D	√	√	- -	- -	- -	D	- -	√	- -	C
NSTAR Electric Co.	MA	D	√	- -	- -	- -	- -	D	- -	√	√	- -
Public Service Co. of New Hampshi	NH	√	- -	- -	- -	- -	- -	- -	√	√	- -	- -
Western Massachussetts Electric Co.	MA	D	√	√	- -	√	- -	D	- -	√	√	- -
EXELON CORP.												
Baltimore G&E	MD	D	√	√	- -	- -	- -	D	√	- -	√	P
Commonwealth Edison	IL	D	√	- -	- -	√	√	D	√	√	√	O
PECO Energy	PA	D	√	- -	- -	- -	- -	D	√	- -	√	O
Atlantic City Electric	NJ	D	√	- -	- -	√	√	D	- -	- -	√	P
Delmarva P&L	MD	D	√	√	- -	- -	- -	D	√	- -	- -	P
Potomac Electric Pwr	DC	D	- -	- -	√	√	- -	D	√	- -	√	P
FORTIS, INC.												
UNS Electric	AZ	√	√	- -	√	√	- -	- -	- -	√	√	- -
Central Hudson Gas & Electric	NY	D	- -	√	- -	√	- -	- -	- -	- -	- -	C
NORTHWESTERN CORP.												
NorthWestern Corp.	MT	√	√	- -	- -	- -	- -	- -	- -	- -	√	- -
NorthWestern Corp.	SD	√	√	- -	- -	- -	- -	- -	- -	- -	- -	- -
PPL CORP.												
Kentucky Utilities Co.	KY	√	√	- -	√	√	√	- -	- -	- -	√	O
Louisville Gas & Electric Co.	KY	√	√	- -	√	√	√	- -	- -	- -	√	O
PPL Electric Utilities Corp.	PA	D	√	- -	- -	- -	- -	D	√	√	√	O

UTILITY GROUP ELECTRIC OPERATING COS.

Holding Company/ Operating Company	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital: Gener-ation Capacity	New Capital: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
PUB SV ENTERPRISE GRP												
Pub Service Electric & Gas Co.	MN	√	√	- -	- -	√	√	- -	- -	√	- -	C
SEMPRA ENERGY												
San Diego Gas & Electric	CA	√	- -	√	- -	- -	- -	- -	- -	- -	- -	C
SOUTHERN CO.												
Alabama Power Co.	AL	√	- -	- -	- -	- -	√	√	- -	- -	√	C
Georgia Power Co.	GA	√	- -	- -	- -	- -	- -	√	- -	- -	- -	C
Gulf Power Co.	FL	√	√	- -	- -	- -	√	√	- -	- -	√	C
Mississippi Power Co.	MS	√	√	- -	√	- -	√	- -	- -	- -	√	O
WEC ENERGY GROUP												
Wisconsin Electric Power Co.	WI	√	- -	- -	- -	- -	- -	- -	- -	- -	√	C
Wisconsin Public Service Corp.	WI	√	- -	- -	- -	- -	- -	- -	- -	- -	√	C
XCEL ENERGY, INC.												
Northern States Power Co. (MN)	MN	√	√	√	- -	√	√	- -	- -	√	- -	C
Northern States Power Co. (WI)	WI	√	- -	- -	- -	- -	- -	- -	- -	- -	√	C
Public Service Co. of Colorado	CO	√	√	- -	- -	√	√	√	√	- -	√	- -
Southwestern Public Service Co.	TX	√	√	- -	- -	- -	- -	- -	√	√	√	- -

Sources:

(a) Regulatory Research Associates, Regulatory Focus, *"Adjustment Clauses-A State-by-State Overview,"* Sep. 12, 2017.

(b) Edison Electric Institute, *"Alternative Regulation for Emerging Utility Challenges: 2015 Update,"* Nov. 11, 2015.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

LIR - Limited issue reopeners.

CAPITAL STRUCTURE

UTILITY GROUP

		At Fiscal Year-End 2017 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Algonquin Pwr & Util	48.1%	2.7%	49.2%	n/a	n/a	n/a
2	Alliant Energy	52.6%	2.2%	45.2%	50.0%	0.0%	50.0%
3	Ameren Corp.	52.0%	0.0%	48.0%	49.0%	1.0%	50.0%
4	Avangrid, Inc.	26.3%	0.0%	73.7%	36.5%	0.0%	63.5%
5	Black Hills Corp.	63.1%	0.0%	36.9%	54.0%	0.0%	46.0%
6	CMS Energy Corp.	69.5%	0.0%	30.5%	62.0%	0.5%	37.5%
7	Consolidated Edison	51.0%	0.0%	49.0%	48.5%	0.0%	51.5%
8	DTE Energy Co.	55.2%	0.0%	44.8%	57.0%	0.0%	43.0%
9	Duke Energy Corp.	55.6%	0.0%	44.4%	56.5%	0.0%	43.5%
10	Emera Inc.	65.9%	3.4%	30.7%	60.0%	3.3%	36.7%
11	Entergy Corp.	64.8%	0.9%	34.4%	60.0%	0.5%	39.5%
12	Eversource Energy	52.3%	0.7%	47.0%	54.5%	1.0%	44.5%
13	Exelon Corp.	51.6%	0.0%	48.4%	50.0%	0.0%	50.0%
14	Fortis Inc.	56.1%	4.3%	39.7%	53.0%	4.0%	43.0%
15	NorthWestern Corp.	50.0%	0.0%	50.0%	46.0%	0.0%	54.0%
16	PPL Corp.	65.2%	0.0%	34.8%	56.0%	0.0%	44.0%
17	Pub Sv Enterprise Grp.	48.6%	0.0%	51.4%	49.5%	0.0%	50.5%
18	Sempra Energy	55.8%	0.1%	44.1%	56.0%	0.0%	44.0%
19	Southern Company	65.2%	0.4%	34.4%	58.5%	0.0%	41.5%
20	WEC Energy Group	50.3%	0.2%	49.6%	48.0%	0.0%	52.0%
21	Xcel Energy Inc.	56.7%	0.0%	43.3%	58.0%	0.0%	42.0%
	Average	**55.0%**	**0.7%**	**44.3%**	**53.1%**	**0.5%**	**46.3%**
	Excluding High & Low	**55.8%**	**0.8%**	**43.4%**	**53.7%**	**0.4%**	**45.9%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.

UTILITY GROUP ELECTRIC OPERATING COS.

	At Year-End 2017		
Operating Company	**Debt**	**Preferred**	**Common Equity**
ALGONQUIN PWR. & UTIL.			
Empire District Electric Co.	48.5%	0.0%	51.5%
Liberty Utilities (Granite State Elec.)	24.5%	0.0%	75.5%
ALLIANT ENERGY CORP.			
Interstate Power & Light	47.0%	3.9%	49.1%
Wisconsin Power & Light	49.4%	0.0%	50.6%
AMEREN CORP.			
Ameren Illinois Co.	46.1%	1.0%	52.9%
Union Electric Co.	49.3%	1.0%	49.8%
AVANGRID			
Central Maine Pwr	36.2%	0.0%	63.8%
NY State E&G	46.7%	0.0%	53.3%
Rochester G&E	50.4%	0.0%	49.6%
United Illuminating	44.0%	0.0%	56.0%
BLACK HILLS CORP.			
Black Hills Power	46.5%	0.0%	53.5%
Cheyenne Light Fuel & Power	46.0%	0.0%	54.0%
CMS ENERGY			
Consumers Energy Co.	47.7%	0.3%	52.0%
CONSOLIDATED EDISON			
Consolidated Edison of NY	51.6%	0.0%	48.4%
Orange & Rockland	50.5%	0.0%	49.5%
DTE ENERGY CO.			
DTE Electric Co.	49.0%	0.0%	51.0%
DUKE ENERGY			
Duke Energy Carolinas	47.1%	0.0%	52.9%
Duke Energy Florida	55.8%	0.0%	44.2%
Duke Energy Indiana	47.9%	0.0%	52.1%
Duke Energy Ohio	39.5%	0.0%	60.5%
Duke Energy Progress	48.1%	0.0%	51.9%
Progress Energy Inc.	57.0%	0.0%	43.0%
EMERA INC.			
Emera Maine	38.2%	0.0%	61.8%
Tampa Electric Co.	42.6%	0.0%	57.4%
ENTERGY CORP.			
Entergy Arkansas Inc.	55.1%	0.6%	44.3%
Entergy Louisiana LLC	53.6%	0.0%	46.4%
Entergy Mississippi Inc.	51.5%	0.8%	47.7%
Entergy New Orleans Inc.	50.3%	0.0%	49.7%
Entergy Texas Inc.	55.7%	0.0%	44.3%
EVERSOURCE ENERGY			
Connecticut Light & Power	45.2%	1.7%	53.0%
NSTAR Electric Co.	45.8%	0.7%	53.6%
Public Service Co. of New Hampshire	42.6%	0.0%	57.4%
Western Massachussetts Electric Co.	45.8%	0.0%	54.2%

UTILITY GROUP ELECTRIC OPERATING COS.

	At Year-End 2017		
Operating Company	**Debt**	**Preferred**	**Common Equity**
EXELON CORP.			
Delmarva Power and Light	49.3%	0.0%	50.7%
Baltimore Gas & Electric Co.	45.1%	0.0%	54.9%
Commonweath Edison Co.	44.3%	0.0%	55.7%
PECO Energy Co.	44.8%	0.0%	55.2%
Potomac Electric Power Co.	50.1%	0.0%	49.9%
Atlantic City Electric Co.	51.8%	0.0%	48.2%
FORTIS, INC.			
UNS Electric	46.4%	0.0%	53.6%
Central Hudson Gas & Electric	49.4%	0.0%	50.6%
NORTHWESTERN CORP.			
NorthWestern Corporation	50.0%	0.0%	50.0%
PPL CORP.			
Kentucky Utilities Co.	n/a	n/a	n/a
Louisville Gas & Electric Co.	n/a	n/a	n/a
PPL Electric Utilities Corp.	45.2%	0.0%	54.8%
PUB SV ENTERPRISE GRP			
Pub Service Electric & Gas Co.	44.4%	0.0%	55.6%
SEMPRA ENERGY			
San Diego Gas & Electric	49.7%	0.0%	50.3%
SOUTHERN CO.			
Alabama Power Co.	51.7%	2.0%	46.3%
Georgia Power Co.	50.0%	0.0%	50.0%
Gulf Power Co.	45.6%	0.0%	54.4%
Mississippi Power Co.	60.0%	0.9%	39.1%
WEC ENERGY GROUP			
Wisconsin Electric Power Co. (We Energies)	42.8%	0.5%	56.7%
Wisconsin Public Service Corp.	44.2%	0.0%	55.8%
XCEL ENERGY, INC.			
Northern States Power Co. (MN)	47.7%	0.0%	52.3%
Northern States Power Co. (WI)	45.1%	0.0%	54.9%
Public Service Co. of Colorado	43.7%	0.0%	56.3%
Southwestern Public Service Co.	46.1%	0.0%	53.9%

Minimum	**24.5%**	**0.0%**	**39.1%**
Maximum	**60.0%**	**3.9%**	**75.5%**
Simple Average	**47.3%**	**0.2%**	**52.4%**
Weighted Average	**48.5%**	**0.2%**	**51.2%**

Sources: Most recent Company 10-K and FERC Form 1 reports.

DCF MODEL - UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Algonquin Pwr & Util	$12.72	$0.68	5.4%
2	Alliant Energy	$42.31	$1.34	3.2%
3	Ameren Corp.	$60.50	$1.88	3.1%
4	Avangrid, Inc.	$52.03	$1.76	3.4%
5	Black Hills Corp.	$60.80	$1.96	3.2%
6	CMS Energy Corp.	$47.03	$1.48	3.1%
7	Consolidated Edison	$77.60	$2.91	3.7%
8	DTE Energy Co.	$104.35	$3.72	3.6%
9	Duke Energy Corp.	$79.27	$3.71	4.7%
10	Emera Inc.	$42.39	$2.26	5.3%
11	Entergy Corp.	$80.72	$3.62	4.5%
12	Eversource Energy	$58.25	$2.05	3.5%
13	Exelon Corp.	$42.11	$1.45	3.4%
14	Fortis Inc.	$42.23	$1.78	4.2%
15	NorthWestern Corp.	$57.66	$2.25	3.9%
16	PPL Corp.	$28.39	$1.66	5.8%
17	Pub Sv Enterprise Grp.	$52.61	$1.82	3.5%
18	Sempra Energy	$115.17	$3.72	3.2%
19	Southern Company	$46.85	$2.42	5.2%
20	WEC Energy Group	$64.19	$2.28	3.6%
21	Xcel Energy Inc.	$45.51	$1.56	3.4%
	Average			**4.0%**

(a) Average of closing prices for 30 trading days ended Jul. 27, 2018.

(b) The Value Line Investment Survey, Summary & Index (Jul. 27, 2018).

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Earnings Growth						
						S&P		br+sv
	Company	V Line	IBES	Zacks	Bloomberg	Capital IQ	FactSet	Growth
1	Algonquin Pwr & Util	n/a	10.0%	8.0%	8.0%	10.1%	17.6%	n/a
2	Alliant Energy	6.5%	5.9%	5.6%	5.9%	5.9%	5.9%	4.4%
3	Ameren Corp.	7.5%	6.3%	6.5%	9.0%	6.6%	7.0%	4.8%
4	Avangrid, Inc.	13.0%	9.7%	9.1%	9.7%	8.9%	9.7%	2.0%
5	Black Hills Corp.	6.5%	3.9%	4.3%	5.0%	5.0%	4.9%	5.7%
6	CMS Energy Corp.	7.0%	7.1%	6.4%	6.4%	6.7%	7.0%	6.2%
7	Consolidated Edison	3.0%	3.4%	4.0%	3.0%	3.2%	3.5%	2.8%
8	DTE Energy Co.	7.0%	5.6%	5.3%	5.5%	5.8%	4.9%	5.4%
9	Duke Energy Corp.	5.5%	4.2%	4.6%	4.4%	4.2%	5.0%	2.3%
10	Emera Inc.	10.5%	7.2%	n/a	13.4%	6.5%	n/a	5.6%
11	Entergy Corp.	2.0%	-0.2%	7.0%	3.0%	9.0%	-2.0%	5.9%
12	Eversource Energy	5.5%	5.7%	5.8%	6.3%	5.3%	5.5%	3.6%
13	Exelon Corp.	8.0%	4.2%	5.7%	5.3%	4.9%	4.9%	5.3%
14	Fortis Inc.	8.0%	4.1%	5.5%	6.0%	5.2%	n/a	3.3%
15	NorthWestern Corp.	3.5%	3.2%	3.0%	2.4%	3.0%	3.0%	3.6%
16	PPL Corp.	2.0%	2.1%	6.0%	8.1%	4.1%	4.3%	7.0%
17	Pub Sv Enterprise Grp.	4.0%	6.3%	6.1%	6.5%	6.3%	6.3%	4.6%
18	Sempra Energy	9.5%	8.5%	8.5%	16.3%	8.4%	13.0%	8.2%
19	Southern Company	3.0%	2.3%	4.5%	4.4%	4.1%	4.0%	4.4%
20	WEC Energy Group	7.0%	4.4%	4.1%	3.0%	6.1%	3.8%	4.3%
21	Xcel Energy Inc.	5.5%	5.9%	5.7%	5.8%	5.8%	5.8%	4.4%

(a) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.
(b) www.finance.yahoo.com (retreived Jul. 17, 2018).
(c) www.zacks.com (retrieved Jul. 18, 2018).
(d) Bloomberg L.P. (retrieved Jul. 13, 2018).
(e) SNL Financial (retrieved Aug. 2, 2018).
(f) www.money.cnn.com (retrieved Jul. 18, 2018).
(g) See Exhibit No. 6.

DCF MODEL - UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

	Company	(a) V Line	(a) IBES	(a) Zacks	(a) Bloomberg	(a) S&P Capital/IQ	(a) FactSet	(a) br+sv Growth
		Earnings Growth						
1	Algonquin Pwr & Util	n/a	15.4%	13.4%	13.4%	15.5%	23.0%	n/a
2	Alliant Energy	9.7%	9.0%	8.7%	9.1%	9.1%	9.0%	7.5%
3	Ameren Corp.	10.6%	9.4%	9.6%	12.1%	9.7%	10.1%	7.9%
4	Avangrid, Inc.	16.4%	13.1%	12.5%	13.1%	12.3%	13.1%	5.4%
5	Black Hills Corp.	9.7%	7.2%	7.5%	8.2%	8.2%	8.1%	9.0%
6	CMS Energy Corp.	10.1%	10.2%	9.5%	9.5%	9.8%	10.1%	9.3%
7	Consolidated Edison	6.7%	7.1%	7.7%	6.7%	6.9%	7.3%	6.5%
8	DTE Energy Co.	10.6%	9.1%	8.9%	9.1%	9.4%	8.4%	8.9%
9	Duke Energy Corp.	10.2%	8.9%	9.3%	9.1%	8.9%	9.7%	7.0%
10	Emera Inc.	15.8%	12.5%	n/a	18.7%	11.9%	n/a	11.0%
11	Entergy Corp.	6.5%	4.3%	11.5%	7.5%	13.4%	2.5%	10.4%
12	Eversource Energy	9.0%	9.2%	9.3%	9.8%	8.8%	9.0%	7.2%
13	Exelon Corp.	11.4%	7.6%	9.1%	8.8%	8.4%	8.4%	8.8%
14	Fortis Inc.	12.2%	8.4%	9.7%	10.2%	9.4%	n/a	7.5%
15	NorthWestern Corp.	7.4%	7.1%	6.9%	6.3%	6.9%	6.9%	7.5%
16	PPL Corp.	7.8%	8.0%	11.8%	13.9%	10.0%	10.1%	12.8%
17	Pub Sv Enterprise Grp.	7.5%	9.8%	9.6%	10.0%	9.7%	9.8%	8.0%
18	Sempra Energy	12.7%	11.7%	11.7%	19.6%	11.7%	16.2%	11.4%
19	Southern Company	8.2%	7.4%	9.7%	9.5%	9.3%	9.2%	9.6%
20	WEC Energy Group	10.6%	8.0%	7.7%	6.5%	9.7%	7.4%	7.8%
21	Xcel Energy Inc.	8.9%	9.3%	9.1%	9.3%	9.2%	9.3%	7.9%
	Average (b)	**10.5%**	**9.4%**	**9.8%**	**10.2%**	**10.2%**	**9.7%**	**8.9%**
	Midpoint (b,c)	**11.9%**	**11.2%**	**10.4%**	**10.7%**	**11.9%**	**11.8%**	**9.9%**

(a) Sum of dividend yield (Exhibit No. 5, p. 1) and respective growth rate (Exhibit No. 5, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - UTILITY GROUP **Exhibit No. 6**

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
			2022				Adjustment				"sv" Factor		
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Algonquin Pwr & Util	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**n/a**
2	Alliant Energy	$2.60	$1.66	$22.85	36.2%	11.4%	1.0040	11.4%	4.1%	0.0055	0.4288	0.24%	**4.4%**
3	Ameren Corp.	$4.00	$2.35	$37.50	41.3%	10.7%	1.0264	10.9%	4.5%	0.0092	0.3478	0.32%	**4.8%**
4	Avangrid, Inc.	$3.25	$2.20	$53.25	32.3%	6.1%	1.0090	6.2%	2.0%	(0.0000)	(0.0143)	0.00%	**2.0%**
5	Black Hills Corp.	$4.25	$2.45	$42.75	42.4%	9.9%	1.0396	10.3%	4.4%	0.0349	0.3893	1.36%	**5.7%**
6	CMS Energy Corp.	$3.00	$1.85	$22.25	38.3%	13.5%	1.0391	14.0%	5.4%	0.0165	0.4765	0.78%	**6.2%**
7	Consolidated Edison	$4.75	$3.30	$58.00	30.5%	8.2%	1.0191	8.3%	2.5%	0.0094	0.2516	0.24%	**2.8%**
8	DTE Energy Co.	$7.50	$4.55	$69.00	39.3%	10.9%	1.0345	11.2%	4.4%	0.0262	0.3581	0.94%	**5.4%**
9	Duke Energy Corp.	$5.50	$4.40	$66.00	20.0%	8.3%	1.0159	8.5%	1.7%	0.0185	0.3231	0.60%	**2.3%**
10	Emera Inc.	$4.30	$3.00	$35.65	30.2%	12.1%	1.0203	12.3%	3.7%	0.0354	0.5400	1.91%	**5.6%**
11	Entergy Corp.	$6.75	$3.90	$56.00	42.2%	12.1%	1.0306	12.4%	5.2%	0.0198	0.3212	0.64%	**5.9%**
12	Eversource Energy	$4.00	$2.50	$42.00	37.5%	9.5%	1.0178	9.7%	3.6%	-	0.3778	0.00%	**3.6%**
13	Exelon Corp.	$3.75	$1.70	$39.75	54.7%	9.4%	1.0266	9.7%	5.3%	0.0039	0.1167	0.05%	**5.3%**
14	Fortis Inc.	$3.50	$2.20	$41.25	37.1%	8.5%	1.0291	8.7%	3.2%	0.0064	0.1316	0.08%	**3.3%**
15	NorthWestern Corp.	$4.00	$2.60	$43.25	35.0%	9.2%	1.0201	9.4%	3.3%	0.0098	0.3346	0.33%	**3.6%**
16	PPL Corp.	$2.75	$1.80	$20.75	34.5%	13.3%	1.0410	13.8%	4.8%	0.0459	0.4813	2.21%	**7.0%**
17	Pub Sv Enterprise Grp.	$3.75	$2.20	$34.75	41.3%	10.8%	1.0233	11.0%	4.6%	-	0.3381	0.00%	**4.6%**
18	Sempra Energy	$8.00	$4.90	$68.50	38.8%	11.7%	1.0466	12.2%	4.7%	0.0679	0.5107	3.47%	**8.2%**
19	Southern Company	$3.50	$2.70	$29.75	22.9%	11.8%	1.0319	12.1%	2.8%	0.0361	0.4591	1.66%	**4.4%**
20	WEC Energy Group	$4.25	$2.75	$35.75	35.3%	11.9%	1.0172	12.1%	4.3%	0.0000	0.4500	0.00%	**4.3%**
21	Xcel Energy Inc.	$3.00	$1.90	$28.00	36.7%	10.7%	1.0244	11.0%	4.0%	0.0097	0.4105	0.40%	**4.4%**

DCF MODEL - UTILITY GROUP

Exhibit No. 6

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2017			**2022**			**Chg**	**2022 Price**				**Common Shares**		
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**M/B**	**2017**	**2022**	**Growth**
1	Algonquin Pwr & Util	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	Alliant Energy	51.0%	$8,193	$4,178	50.0%	$8,700	$4,350	0.8%	$45.00	$35.00	$40.00	1.751	231.35	235.00	0.31%
3	Ameren Corp.	49.8%	$14,420	$7,181	50.0%	$18,700	$9,350	5.4%	$65.00	$50.00	$57.50	1.533	242.63	250.00	0.60%
4	Avangrid, Inc.	74.4%	$20,273	$15,083	63.5%	$26,000	$16,510	1.8%	$60.00	$45.00	$52.50	0.986	309.01	309.00	0.00%
5	Black Hills Corp.	35.5%	$4,818	$1,711	46.0%	$5,525	$2,542	8.2%	$80.00	$60.00	$70.00	1.637	53.54	59.50	2.13%
6	CMS Energy Corp.	32.4%	$13,692	$4,436	37.5%	$17,500	$6,563	8.1%	$50.00	$35.00	$42.50	1.910	281.65	294.00	0.86%
7	Consolidated Edison	51.1%	$30,149	$15,406	51.5%	$36,200	$18,643	3.9%	$85.00	$70.00	$77.50	1.336	310.00	321.00	0.70%
8	DTE Energy Co.	43.8%	$21,697	$9,503	43.0%	$31,200	$13,416	7.1%	$125.00	$90.00	$107.50	1.558	179.39	195.00	1.68%
9	Duke Energy Corp.	46.0%	$90,774	$41,756	43.5%	$112,500	$48,938	3.2%	$110.00	$85.00	$97.50	1.477	700.00	745.00	1.25%
10	Emera Inc.	31.5%	$20,229	$6,380	36.7%	$21,300	$7,816	4.1%	$90.00	$65.00	$77.50	2.174	228.77	248.00	1.63%
11	Entergy Corp.	35.5%	$22,528	$7,997	39.5%	$27,500	$10,863	6.3%	$100.00	$65.00	$82.50	1.473	180.52	193.00	1.35%
12	Eversource Energy	48.2%	$23,018	$11,095	44.5%	$29,800	$13,261	3.6%	$75.00	$60.00	$67.50	1.607	316.89	316.89	0.00%
13	Exelon Corp.	47.8%	$62,422	$29,838	50.0%	$77,900	$38,950	5.5%	$55.00	$35.00	$45.00	1.132	963.34	980.00	0.34%
14	Fortis Inc.	37.1%	$36,108	$13,396	43.0%	$41,700	$17,931	6.0%	$55.00	$40.00	$47.50	1.152	421.10	433.00	0.56%
15	NorthWestern Corp.	49.8%	$3,615	$1,800	54.0%	$4,075	$2,201	4.1%	$75.00	$55.00	$65.00	1.503	49.37	51.00	0.65%
16	PPL Corp.	35.2%	$30,608	$10,774	44.0%	$36,900	$16,236	8.5%	$45.00	$35.00	$40.00	1.928	693.40	780.00	2.38%
17	Pub Sv Enterprise Grp.	53.4%	$25,915	$13,839	50.5%	$34,600	$17,473	4.8%	$60.00	$45.00	$52.50	1.511	505.00	505.00	0.00%
18	Sempra Energy	43.5%	$29,135	$12,674	44.0%	$45,900	$20,196	9.8%	$160.00	$120.00	$140.00	2.044	251.36	296.00	3.32%
19	Southern Company	35.0%	$68,953	$24,134	41.5%	$80,000	$33,200	6.6%	$65.00	$45.00	$55.00	1.849	1007.60	1110.00	1.95%
20	WEC Energy Group	51.9%	$18,238	$9,466	52.0%	$21,625	$11,245	3.5%	$70.00	$60.00	$65.00	1.818	315.57	315.60	0.00%
21	Xcel Energy Inc.	44.1%	$25,975	$11,455	42.0%	$34,800	$14,616	5.0%	$50.00	$45.00	$47.50	1.696	507.76	522.50	0.57%

(a) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2022 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change in common equity.
(h) Average of High and Low expected market prices divided by 2022 BVPS.

CAPM - CURRENT BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Algonquin Pwr & Util	2.3%	10.9%	13.2%	3.1%	10.1%	n/a	n/a	$4,591.0	0.86%	n/a
2	Alliant Energy	2.3%	10.9%	13.2%	3.1%	10.1%	0.70	10.2%	$9,986.1	0.83%	11.0%
3	Ameren Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$14,949.7	0.55%	10.2%
4	Avangrid, Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	0.40	7.1%	$16,307.4	0.55%	7.7%
5	Black Hills Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.85	11.7%	$3,290.7	1.36%	13.0%
6	CMS Energy Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$13,537.4	0.55%	10.2%
7	Consolidated Edison	2.3%	10.9%	13.2%	3.1%	10.1%	0.50	8.2%	$24,637.4	0.55%	8.7%
8	DTE Energy Co.	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$19,222.7	0.55%	10.2%
9	Duke Energy Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.60	9.2%	$56,430.5	-0.30%	8.9%
10	Emera Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$9,741.4	0.83%	10.5%
11	Entergy Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$14,858.1	0.55%	10.2%
12	Eversource Energy	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$19,745.5	0.55%	10.2%
13	Exelon Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.70	10.2%	$40,783.1	-0.30%	9.9%
14	Fortis Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	0.70	10.2%	$17,930.4	0.55%	10.7%
15	NorthWestern Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.65	9.7%	$3,110.4	1.36%	11.0%
16	PPL Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.75	10.7%	$19,980.0	0.55%	11.2%
17	Pub Sv Enterprise Grp.	2.3%	10.9%	13.2%	3.1%	10.1%	0.70	10.2%	$26,374.3	-0.30%	9.9%
18	Sempra Energy	2.3%	10.9%	13.2%	3.1%	10.1%	0.75	10.7%	$30,526.3	-0.30%	10.4%
19	Southern Company	2.3%	10.9%	13.2%	3.1%	10.1%	0.55	8.7%	$48,537.8	-0.30%	8.4%
20	WEC Energy Group	2.3%	10.9%	13.2%	3.1%	10.1%	0.60	9.2%	$20,693.1	0.55%	9.7%
21	Xcel Energy Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	0.60	9.2%	$23,571.4	0.55%	9.7%
	Average							**9.6%**			**10.1%**
	Midpoint (g)							**9.4%**			**10.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved Aug 1, 2018).

(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Aug 1, 2018)., http://finance.yahoo.com (retrieved Aug 1, 2018)., and www.zacks.com (retrieved Aug 1, 2018)..

(c) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2018 based on data from the Federal Reserve at

(d) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.

(e) www.valueline.com (retrieved Jul. 17, 2018).

(f) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(g) Average of low and high values.

CAPM - PROJECTED BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Algonquin Pwr & Util	2.3%	10.9%	13.2%	4.0%	9.2%	n/a	n/a	$4,591.0	0.86%	n/a
2	Alliant Energy	2.3%	10.9%	13.2%	4.0%	9.2%	0.70	10.4%	$9,986.1	0.83%	11.3%
3	Ameren Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$14,949.7	0.55%	10.5%
4	Avangrid, Inc.	2.3%	10.9%	13.2%	4.0%	9.2%	0.40	7.7%	$16,307.4	0.55%	8.2%
5	Black Hills Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.85	11.8%	$3,290.7	1.36%	13.2%
6	CMS Energy Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$13,537.4	0.55%	10.5%
7	Consolidated Edison	2.3%	10.9%	13.2%	4.0%	9.2%	0.50	8.6%	$24,637.4	0.55%	9.2%
8	DTE Energy Co.	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$19,222.7	0.55%	10.5%
9	Duke Energy Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.60	9.5%	$56,430.5	-0.30%	9.2%
10	Emera Inc.	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$9,741.4	0.83%	10.8%
11	Entergy Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$14,858.1	0.55%	10.5%
12	Eversource Energy	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$19,745.5	0.55%	10.5%
13	Exelon Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.70	10.4%	$40,783.1	-0.30%	10.1%
14	Fortis Inc.	2.3%	10.9%	13.2%	4.0%	9.2%	0.70	10.4%	$17,930.4	0.55%	11.0%
15	NorthWestern Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.65	10.0%	$3,110.4	1.36%	11.3%
16	PPL Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.75	10.9%	$19,980.0	0.55%	11.5%
17	Pub Sv Enterprise Grp.	2.3%	10.9%	13.2%	4.0%	9.2%	0.70	10.4%	$26,374.3	-0.30%	10.1%
18	Sempra Energy	2.3%	10.9%	13.2%	4.0%	9.2%	0.75	10.9%	$30,526.3	-0.30%	10.6%
19	Southern Company	2.3%	10.9%	13.2%	4.0%	9.2%	0.55	9.1%	$48,537.8	-0.30%	8.8%
20	WEC Energy Group	2.3%	10.9%	13.2%	4.0%	9.2%	0.60	9.5%	$20,693.1	0.55%	10.1%
21	Xcel Energy Inc.	2.3%	10.9%	13.2%	4.0%	9.2%	0.60	9.5%	$23,571.4	0.55%	10.1%
	Average							**10.0%**			**10.4%**
	Midpoint (g)							**9.8%**			**10.7%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved Aug 1, 2018).

(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Aug 1, 2018)., http://finance.yahoo.com (retrieved Aug 1, 2018)., and www.zacks.com (retrieved Aug 1, 2018)..

(c) Average yield on 30-year Treasury bonds for 2019-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 1, 2018); IHS Global Insight (Jun. 6, 2018); & Wolters Kluwer, Blue Chip Financial Forecasts, (Jun. 1, 2018).

(d) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.

(e) www.valueline.com (retrieved Jul. 17, 2018).

(f) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(g) Average of low and high values.

EMPIRICAL CAPM - CURRENT BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	*RP* [1]	Beta	Weight	*RP* [2]	RP	K_e	Cap	Adjustment	K_e
1	Algonquin Pwr & Util	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	n/a	75%	n/a	n/a	n/a	$4,591.0	0.86%	n/a
2	Alliant Energy	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.70	75%	5.3%	7.8%	10.9%	$9,986.1	0.83%	11.8%
3	Ameren Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$14,949.7	0.55%	11.1%
4	Avangrid, Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.40	75%	3.0%	5.6%	8.7%	$16,307.4	0.55%	9.2%
5	Black Hills Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.85	75%	6.4%	9.0%	12.1%	$3,290.7	1.36%	13.4%
6	CMS Energy Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$13,537.4	0.55%	11.1%
7	Consolidated Edison	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.50	75%	3.8%	6.3%	9.4%	$24,637.4	0.55%	10.0%
8	DTE Energy Co.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$19,222.7	0.55%	11.1%
9	Duke Energy Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.60	75%	4.5%	7.1%	10.2%	$56,430.5	-0.30%	9.9%
10	Emera Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$9,741.4	0.83%	11.4%
11	Entergy Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$14,858.1	0.55%	11.1%
12	Eversource Energy	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$19,745.5	0.55%	11.1%
13	Exelon Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.70	75%	5.3%	7.8%	10.9%	$40,783.1	-0.30%	10.6%
14	Fortis Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.70	75%	5.3%	7.8%	10.9%	$17,930.4	0.55%	11.5%
15	NorthWestern Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.65	75%	4.9%	7.4%	10.5%	$3,110.4	1.36%	11.9%
16	PPL Corp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.75	75%	5.7%	8.2%	11.3%	$19,980.0	0.55%	11.9%
17	Pub Sv Enterprise Grp.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.70	75%	5.3%	7.8%	10.9%	$26,374.3	-0.30%	10.6%
18	Sempra Energy	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.75	75%	5.7%	8.2%	11.3%	$30,526.3	-0.30%	11.0%
19	Southern Company	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.55	75%	4.2%	6.7%	9.8%	$48,537.8	-0.30%	9.5%
20	WEC Energy Group	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.60	75%	4.5%	7.1%	10.2%	$20,693.1	0.55%	10.7%
21	Xcel Energy Inc.	2.3%	10.9%	13.2%	3.1%	10.1%	25%	2.5%	0.60	75%	4.5%	7.1%	10.2%	$23,571.4	0.55%	10.7%
	Average												**10.5%**			**11.0%**
	Midpoint (h)												**10.4%**			**11.3%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved Aug 1, 2018).

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(c) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2018 based on data from the Federal Reserve at https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15.

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.

(f) www.valueline.com (retrieved Jul. 17, 2018).

(g) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(h) Average of low and high values.

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				**Market**										**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**			**Total**	**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Algonquin Pwr & Util	2.3%	10.9%	13.2%	4.0%	9.2%	25%	2.3%	n/a	75%	n/a	n/a	n/a	$ 4,591.0	0.86%	n/a
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4	Avangrid, Inc.	2.3%	10.9%	13.2%	4.0%	9.2%	25%	2.3%	0.40	75%	2.8%	5.1%	9.1%	$ 16,307.4	0.55%	9.6%
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6	CMS Energy Corp.	2.3%	10.9%	13.2%	4.0%	9.2%	25%	2.3%	0.65	75%	4.5%	6.8%	10.8%	$ 13,537.4	0.55%	11.3%
7	Consolidated Edison	2.3%	10.9%	13.2%	4.0%	9.2%	25%	2.3%	0.50	75%	3.5%	5.8%	9.8%	$ 24,637.4	0.55%	10.3%
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	Average												**10.8%**			**11.2%**
	Midpoint (h)												**10.6%**			**11.6%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved Aug 1, 2018).

(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Aug 1, 2018)., http://finance.yahoo.com (retrieved Aug 1, 2018)., and www.zacks.com (retrieved Aug 1, 2018)..

(c) Average yield on 30-year Treasury bonds for 2019-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 1, 2018); IHS Global Insight (Jun. 6, 2018); & Wolters Kluwer, Blue Chip Financial Forecasts, (Jun. 1, 2018).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.

(f) www.valueline.com (retrieved Jul. 17, 2018).

(g) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(h) Average of low and high values.

CURRENT BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.28%
(b)	Average Utility Bond Yield	4.28%
	Change in Bond Yield	-4.00%
(c)	Risk Premium/Interest Rate Relationship	-0.4318
	Adjustment to Average Risk Premium	1.73%
(a)	Average Risk Premium over Study Period	3.71%
	Adjusted Risk Premium	**5.44%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield	4.60%
	Adjusted Equity Risk Premium	5.44%
	Risk Premium Cost of Equity	**10.04%**

(a) Exhibit No. 9, page 3.

(b) Average bond yield on all utility bonds and Baa subset for the six-months ending Jul. 2018 based on data from Moody's Investors Service at www.credittrends.com.

(c) Exhibit No. 9, page 4.

PROJECTED BOND YIELD

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.28%
(b)	Average Utility Bond Yield 2019-2023	5.94%
	Change in Bond Yield	-2.34%
(c)	Risk Premium/Interest Rate Relationship	-0.4318
	Adjustment to Average Risk Premium	1.01%
(a)	Average Risk Premium over Study Period	3.71%
	Adjusted Risk Premium	**4.72%**
Implied Cost of Equity		
(b)	Baa Utility Bond Yield 2019-2023	6.26%
	Adjusted Equity Risk Premium	4.72%
	Risk Premium Cost of Equity	**10.98%**

(a) Exhibit No. 9, page 3.

(b) Yields on all utility bonds and Baa subset based on data from IHS Global Insight (Jun. 6, 2018); Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018); & Moody's Investors Service at www.credittrends.com.

(c) Exhibit No. 9, page 4.

ELECTRIC UTILITY RISK PREMIUM

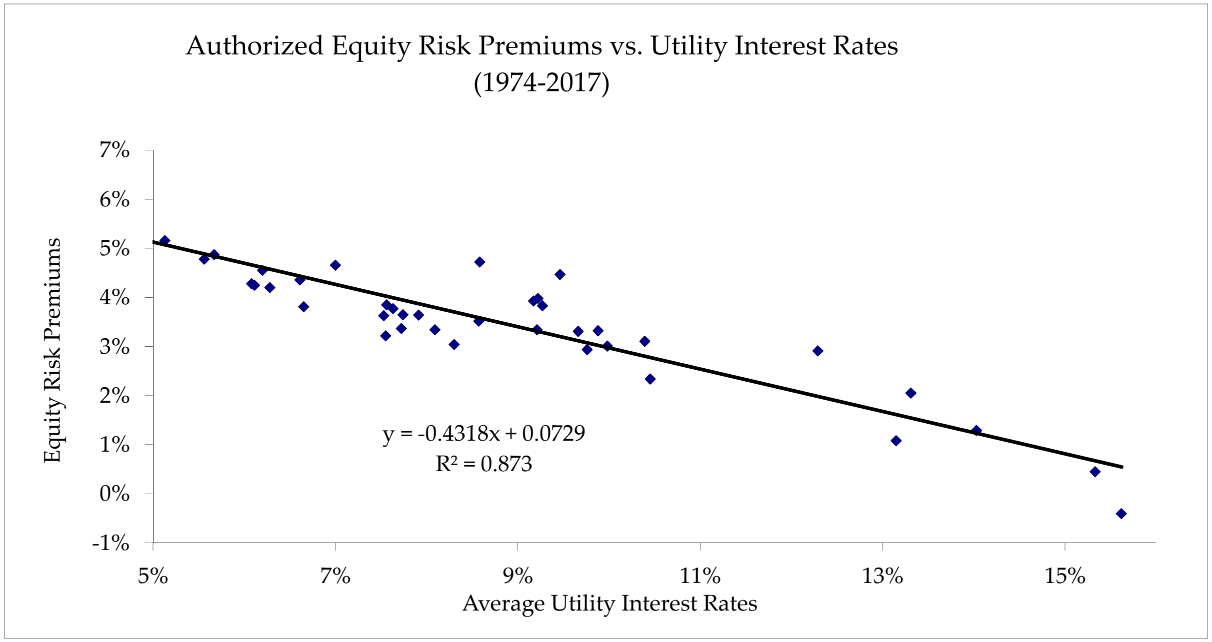
AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
2014	9.92%	4.41%	5.51%
2015	9.85%	4.37%	5.48%
2016	9.77%	4.11%	5.66%
2017	9.74%	4.07%	5.67%
Average	11.99%	8.28%	3.71%

(a) Major Rate Case Decisions, *Regulatory Focus*, Regulatory Research Associates; *UtilityScope Regulatory Service*, Argus.

(b) Moody's Investors Service.

REGRESSION RESULTS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.934345084
R Square	0.873000736
Adjusted R Square	0.869976944
Standard Error	0.004907631
Observations	44

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006953548	0.006953548	288.7105784	1.97526E-20
Residual	42	0.001011563	2.40848E-05		
Total	43	0.007965112			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072885799	0.002231138	32.66753843	1.73387E-31	0.068383179	0.077388419	0.068383179	0.077388419
X Variable 1	-0.431830074	0.025414498	-16.99148547	1.97526E-20	-0.483118608	-0.380541541	-0.483118608	-0.380541541

EXPECTED EARNINGS APPROACH **Exhibit No. 10**

UTILITY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	Algonquin Pwr & Util	n/a	n/a	n/a
2	Alliant Energy	11.5%	1.0040	11.5%
3	Ameren Corp.	10.5%	1.0264	10.8%
4	Avangrid, Inc.	6.0%	1.0090	6.1%
5	Black Hills Corp.	10.0%	1.0396	10.4%
6	CMS Energy Corp.	13.5%	1.0391	14.0%
7	Consolidated Edison	8.5%	1.0191	8.7%
8	DTE Energy Co.	11.0%	1.0345	11.4%
9	Duke Energy Corp.	8.5%	1.0159	8.6%
10	Emera Inc.	12.5%	1.0203	12.8%
11	Entergy Corp.	12.0%	1.0306	12.4%
12	Eversource Energy	9.5%	1.0178	9.7%
13	Exelon Corp.	9.5%	1.0266	9.8%
14	Fortis Inc.	8.5%	1.0291	8.7%
15	NorthWestern Corp.	9.5%	1.0201	9.7%
16	PPL Corp.	13.0%	1.0410	13.5%
17	Pub Sv Enterprise Grp.	11.0%	1.0233	11.3%
18	Sempra Energy	11.5%	1.0466	12.0%
19	Southern Company	12.0%	1.0319	12.4%
20	WEC Energy Group	12.0%	1.0172	12.2%
21	Xcel Energy Inc.	10.5%	1.0244	10.8%
	Average (d)			**11.1%**
	Midpoint (d,e)			**11.3%**

(a) The Value Line Investment Survey (May 18, Jun. 15, & Jul. 27, 2018); Jun. 22, 2018 for Emera.

(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. 6.

(c) (a) x (b).

(d) Excludes highlighted values.

(e) Average of low and high values.

VALUE LINE ELECTRIC UTILITY INDUSTRY

No.	Sym	Company	(1) Date	(2) Shares Issued	(3) Offering Price	(4) Underwriting Discount (per share)	(5) Underwriting Discount	(6) Offering Expense	(7) Total Flotation Costs	(8) Gross Proceeds Before Flot. Costs	(9) Flotation Cost (%)
1	ALE	ALLETE	2/27/2014	3,220,000	$49.75	$1.74125	$5,606,825	$450,000	$6,056,825	$160,195,000	3.781%
2	LNT	Alliant Energy	7/3/2003	17,250,000	$19.25	$0.77000	$13,282,500	$370,000	$13,652,500	$332,062,500	4.111%
3	AEE	Ameren Corp.	9/10/2009	21,850,000	$25.25	$0.75750	$16,551,375	$450,000	$17,001,375	$551,712,500	3.082%
4	AEP	American Elec Pwr	4/2/2009	69,000,000	$24.50	$0.73500	$50,715,000	$400,000	$51,115,000	$1,690,500,000	3.024%
5	AGR	AVANGRID, Inc.					N/A				
6	AVA	Avista Corp.	12/13/2006	3,162,500	$25.05	$0.48000	$1,518,000	$300,000	$1,818,000	$79,220,625	2.295%
7	BKH	Black Hills Corp.	11/19/2015	6,325,000	$40.25	$1.40875	$8,910,344	$1,200,000	$10,110,344	$254,581,250	3.971%
8	CNP	CenterPoint Energy	6/10/2010	25,300,000	$12.90	$0.45150	$11,422,950	$390,000	$11,812,950	$326,370,000	3.619%
9	CMS	CMS Energy Corp.	3/31/2005	23,000,000	$12.25	$0.42880	$9,862,400	$325,000	$10,187,400	$281,750,000	3.616%
10	ED	Consolidated Edison	8/10/2017	4,100,000	$83.77	$0.28990	$1,188,590	$350,000	$1,538,590	$343,457,410	0.448%
11	D	Dominion Energy	4/6/2016	10,200,000	$74.16	$0.42000	$4,284,000	$200,000	$4,484,000	$756,432,000	0.593%
12	DTE	DTE Energy Co.	6/20/2002	6,325,000	$43.25	$1.40560	$8,890,420	$250,000	$9,140,420	$273,556,250	3.341%
13	DUK	Duke Energy Corp.	3/2/2016	10,637,500	$72.00	$2.16000	$22,977,000	$400,000	$23,377,000	$765,900,000	3.052%
14	EIX	Edison International					N/A				
15	EE	El Paso Electric Co.					N/A				
16	ETR	Entergy Corp.					N/A				
17	ES	Eversource Energy	3/17/2009	18,975,000	$20.20	$0.65650	$12,457,088	$350,000	$12,807,088	$383,295,000	3.341%
18	EXC	Exelon Corp.	6/13/2014	57,500,000	$35.00	$1.05000	$60,375,000	$600,000	$60,975,000	$2,012,500,000	3.030%
19	FE	FirstEnergy Corp.	9/15/2003	32,200,000	$30.00	$0.97500	$31,395,000	$423,000	$31,818,000	$966,000,000	3.294%
20	FTS	Fortis Inc.					N/A				
21	GXP	Great Plains Energy	9/29/2016	60,490,000	$26.45	$0.79350	$47,998,815	$500,000	$48,498,815	$1,599,960,500	3.031%
22	HE	Hawaiian Elec.	3/20/2013	7,000,000	$26.75	$1.00312	$7,021,840	$450,000	$7,471,840	$187,250,000	3.990%
23	IDA	IDACORP, Inc.	12/10/2004	4,025,000	$30.00	$1.20000	$4,830,000	$300,000	$5,130,000	$120,750,000	4.248%
24	MGEE	MGE Energy	9/10/2004	1,265,000	$31.85	$1.03500	$1,309,275	$125,000	$1,434,275	$40,290,250	3.560%
25	NEE	NextEra Energy, Inc.	11/3/2016	13,800,000	$124.00	$1.89000	$26,082,000	$750,000	$26,832,000	$1,711,200,000	1.568%
26	NWE	NorthWestern Corp.	9/30/2015	1,100,000	$51.81	$1.33000	$1,463,000	$1,000,000	$2,463,000	$56,991,000	4.322%
27	OGE	OGE Energy Corp.	8/22/2003	5,324,074	$21.60	$0.79000	$4,206,018	$325,000	$4,531,018	$114,999,998	3.940%
28	OTTR	Otter Tail Corp.					N/A				
29	PCG	PG&E Corp.	8/17/2016	4,900,000	$63.15	$0.30000	$1,470,000	$175,000	$1,645,000	$309,435,000	0.532%
30	PNW	Pinnacle West Capital	4/9/2010	6,900,000	$38.00	$1.33000	$9,177,000	$190,000	$9,367,000	$262,200,000	3.572%
31	PNM	PNM Resources	12/7/2006	5,750,000	$30.79	$1.07800	$6,198,500	$250,000	$6,448,500	$177,042,500	3.642%
32	POR	Portland General Elec.	6/13/2013	12,765,000	$29.50	$0.95875	$12,238,444	$600,000	$12,838,444	$376,567,500	3.409%
33	PPL	PPL Corp.	4/11/2012	11,385,000	$27.02	$0.64000	$7,286,400	$750,000	$8,036,400	$307,622,700	2.612%
34	PEG	Pub Sv Enterprise Grp.	10/2/2003	9,487,500	$41.75	$1.25250	$11,883,094	$350,000	$12,233,094	$396,103,125	3.088%
35	SCG	SCANA Corp.	5/13/2010	8,222,500	$37.00	$1.29500	$10,648,138	$350,000	$10,998,138	$304,232,500	3.615%
36	SRE	Sempra Energy	1/5/2018	26,869,158	$107.00	$1.92600	$51,749,998	$1,500,000	$53,249,998	$2,874,999,906	1.852%
37	SO	Southern Company	8/18/2016	32,500,000	$49.30	$1.66000	$53,950,000	$557,000	$54,507,000	$1,602,250,000	3.402%
38	VVC	Vectren Corp.	2/26/2007	5,290,000	$28.33	$0.99000	$5,237,100	$425,000	$5,662,100	$149,865,700	3.778%
39	WEC	WEC Energy Group					N/A				
40	WR	Westar Energy	9/25/2013	9,200,000	$31.15	$1.09025	$10,030,300	$250,000	$10,280,300	$286,580,000	3.587%
41	XEL	Xcel Energy Inc.	8/4/2010	21,850,000	$21.50	$0.64500	$14,093,250	$600,000	$14,693,250	$469,775,000	3.128%
		Average									**3.102%**

Column Notes:

(1-4) SEC Form 424B for each company's most recent open-market common stock issuance.
(5) Column (2) * Column (4)
(6) SEC Form 424B for each company's most recent open-market common stock issuance.
(7) Column (5) + Column (6)
(8) Column (2) * Column (3)
(9) Column (7) / Column (8)

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	AT&T Inc.	Telecommunications	$ 31.83	$ 2.02	6.3%
2	Church & Dwight	Household Products	$ 53.40	$ 0.87	1.6%
3	Coca-Cola	Beverage	$ 44.43	$ 1.61	3.6%
4	Federal Realty	REIT	$ 124.14	$ 4.06	3.3%
5	Kellogg	Food Processing	$ 69.54	$ 2.22	3.2%
6	Kimberly-Clark	Household Products	$ 104.56	$ 4.00	3.8%
7	Procter & Gamble	Household Products	$ 78.43	$ 2.88	3.7%
8	Smucker (J.M.)	Food Processing	$ 108.46	$ 3.40	3.1%
9	Walmart Inc.	Retail Store	$ 86.16	$ 2.08	2.4%
	Average				**3.5%**

(a) Average of closing prices for 30 trading days ended Jul. 27, 2018.

(b) The Value Line Investment Survey, Summary & Index (Jul. 27, 2018).

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)	(f)
		Earnings Growth					
	Company	V Line	IBES	Zacks	Bloomberg	S&P Capital IQ	FactSet
1	AT&T Inc.	5.50%	5.29%	3.42%	-0.50%	7.01%	5.00%
2	Church & Dwight	9.00%	10.45%	10.02%	10.24%	10.18%	10.00%
3	Coca-Cola	6.50%	7.23%	8.05%	8.25%	7.58%	7.75%
4	Federal Realty	n/a	5.00%	6.00%	4.40%	6.00%	4.60%
5	Kellogg	7.00%	6.70%	7.29%	8.02%	8.28%	8.00%
6	Kimberly-Clark	10.50%	6.20%	6.97%	14.07%	6.32%	7.00%
7	Procter & Gamble	9.00%	5.92%	7.16%	7.30%	7.38%	6.50%
8	Smucker (J.M.)	6.50%	4.50%	7.50%	7.00%	21.20%	7.00%
9	Walmart Inc.	5.50%	6.47%	6.73%	6.83%	7.31%	7.25%

(a) The Value Line Investment Survey (Jun. 15, Jun. 22, Jul. 6, Jul. 20, Jul. 27, 2018).
(b) www.finance.yahoo.com (retrieved Jul. 18, 2018).
(c) www.zacks.com (retrieved Jul. 18, 2018).
(d) Bloomberg L.P. (retrieved Jul. 13, 2018).
(e) SNL Financial (retrieved Jun. 5, 2018).
(f) www.money.cnn.com (retrieved Jul. 18, 2018).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)	(a)
		Earnings Growth					
	Company	**V Line**	**IBES**	**Zacks**	**Bloomberg**	**S&P Capital IQ**	**FactSet**
1	AT&T Inc.	11.8%	11.6%	9.8%	5.8%	13.4%	11.3%
2	Church & Dwight	10.6%	12.1%	11.6%	11.9%	11.8%	11.6%
3	Coca-Cola	10.1%	10.9%	11.7%	11.9%	11.2%	11.4%
4	Federal Realty	n/a	8.3%	9.3%	7.7%	9.3%	7.9%
5	Kellogg	10.2%	9.9%	10.5%	11.2%	11.5%	11.2%
6	Kimberly-Clark	14.3%	10.0%	10.8%	17.9%	10.1%	10.8%
7	Procter & Gamble	12.7%	9.6%	10.8%	11.0%	11.1%	10.2%
8	Smucker (J.M.)	9.6%	7.6%	10.6%	10.1%	24.3%	10.1%
9	Walmart Inc.	7.9%	8.9%	9.1%	9.2%	9.7%	9.7%
	Average (b)	**10.9%**	**9.9%**	**10.5%**	**10.4%**	**11.0%**	**10.5%**
	Midpoint (b,c)	**11.1%**	**9.9%**	**10.4%**	**9.8%**	**11.3%**	**9.7%**

(a) Sum of dividend yield (Exhibit No. 12, p. 1) and respective growth rate (Exhibit No. 12, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2018-00294**
ADJUSTMENT OF ITS ELECTRIC RATES	**)**	

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	**CASE NO. 2018-00295**
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	
ELECTRIC AND GAS RATES	**)**	

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

Filed: September 28, 2018

TABLE OF CONTENTS

I. <u>BACKGROUND</u>

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

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

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 previously testified before the Commission on behalf of the Companies in the Commission's review of the Companies' 2016 environmental compliance plans[1] and three recent six-month reviews of the Companies' environmental surcharge mechanisms.[2] I also testified in KU's and LG&E's 2016 base rate cases.[3]

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[1] *Application of Kentucky Utilities Company For Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan For Recovery By Environmental Surcharge*, Case No. 2016-00026 (Ky. PSC filed Jan. 19, 2016); *Application of Louisville Gas and Electric Company For Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan For Recovery By Environmental Surcharge*, Case No. 2016-00027 (Ky. PSC filed Jan. 29, 2016).

[2] *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Six-Month Billing Period Ending October 31, 2017*, Case No. 2018-00051 (Ky. PSC filed Mar. 14, 2018); *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Six-Month Billing Period Ending October 31, 2017*, Case No. 2018-00052 (Ky. PSC filed Mar. 14, 2018); *An Examination By the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company For The Six-Month Billing Period Ending April 30, 2016*, Case No. 2016-00214 (Ky. PSC filed July 28, 2016); *An Examination By the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company For The Six-Month Billing Period Ending April 30, 2016*, Case No. 2016-00215 (Ky. PSC filed July 28, 2016); *An Examination By the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company For the Six-Month Billing Periods Ending April 30, 2014 And October 31, 2014*, Case No. 2015-00020 (Ky. PSC filed Feb. 16, 2015); *An Examination By the Public Service Commission of the*

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to present certain schedules required by 807 KAR 5:001 Section 16 filed with the Companies' applications; (2) to describe the calculation of KU's and LG&E's adjusted net operating income and revenue deficiency for the 12-month forecasted test period, beginning May 1, 2019, and ending April 30, 2020 for KU's electric operations and LG&E's electric and gas operations; (3) to explain certain pro forma adjustments to each revenue requirement calculation; (4) to describe the Companies' accounting treatment for Kentucky state tax reform; (5) to describe the need to establish or update certain regulatory assets and liabilities; and (6) to provide an overview of the Companies' recently updated steam generation depreciation rates.

II. SCHEDULES REQUIRED BY 807 KAR 5:001, SECTION 16(7)

Q. Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(7)?

A. Yes, I am sponsoring the following information for the corresponding filing requirements for each of the Companies:

- Most recent FERC or FCC audit reports — Section 16(7)(i) — Tab 39
- Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone) — Section 16(7)(k) — Tab 41
- Annual report to shareholders and

Environmental Surcharge Mechanism of Louisville Gas and Electric Company For the Six-Month Billing Periods Ending April 30, 2014 And October 31, 2014, Case No. 2015-00021 (Ky. PSC filed Feb. 16, 2015).

[3] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371.

statistical supplements	Section 16(7)(l)	Tab 42
• Current chart of accounts	Section 16(7)(m)	Tab 43
• SEC annual reports (Form 10-Ks, Form 8-Ks, and Form 10-Qs)	Section 16(7)(p)	Tab 46
• Independent auditor's annual opinion report, with any written communication from the auditor which indicates the existence of a material weakness in internal controls	Section 16(7)(q)	Tab 47
• Quarterly reports to stockholders for most recent five quarters	Section 16(7)(r)	Tab 48
• Summary of utility's latest depreciation study with schedules by major plant accounts	Section 16(7)(s)	Tab 49
• Information related to any amounts charged, allocated, or paid to utility by an affiliate or general or home office	Section 16(7)(u)	Tab 51

III. SCHEDULES REQUIRED BY 807 KAR 5:001, SECTION 16(8)

Q. Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(8)?

A. Yes, I am sponsoring the following information for the corresponding filing requirements for each of the Companies:

• Jurisdictional financial summary for base and forecasted periods	Section 16(8)(a)	Tab 54
• Jurisdictional rate base summary for base and forecasted periods	Section 16(8)(b)	Tab 55
• Jurisdictional operating income summary for base and forecasted periods	Section 16(8)(c)	Tab 56
• Summary of jurisdictional adjustments to operating income	Section 16(8)(d)	Tab 57

•	Jurisdictional federal and state income tax summary	Section 16(8)(e)	Tab 58
•	Summary schedules for base and forecasted periods of organizational membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases	Section 16(8)(f)	Tab 59
•	Computation of gross revenue conversion factor for forecasted period	Section 16(8)(h)	Tab 61

IV. PROPERTY VALUATIONS PRESENTED: CAPITALIZATION AND RATE BASE

Q: Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(6)?

A. Yes, I am sponsoring all information required by 807 KAR 5:001 Section 16(6)(f) for each of the Companies.

Q. What are the property valuation measures to be considered by the Commission for ratemaking purposes?

A. Section 278.290 of the Kentucky Revised Statutes requires the Commission to give due consideration to three quantifiable values: original cost (rate base), cost of reproduction as a going concern, and capital structure. The Commission is also required to consider the history and development of the utilities and their property and other elements of value long recognized for ratemaking purposes.

Q. Which property-valuation methodology have the Companies chosen to support their requested rate changes in these cases?

A. The calculation of the Companies' rate base and capitalization valuations are shown on Section 16(7)(h) 11 and 12 at Tab 32 filed with each company's application.

Continuing with the Companies' approach in their six most recent base rate cases, the Companies have chosen the capitalization methodology of property valuation. The Commission approved this approach in each of those base rate cases.

Q. Has the Commission indicated a preference for the utility to continue using the property valuation methodology it has historically used?

A. Yes. The Commission has stated that it "will consider using an approach different from that previously used" only if a justification exists.[4] For example, in Case No. 2000-00080, the Commission considered whether LG&E had presented sufficient evidence to support changing the property valuation methodology it had traditionally used.[5] Here sufficient justification does not exist to support departing from the more than 40 years of using the capitalization valuation methodology to use the rate base property valuation methodology in these cases.

Q. Has the Commission indicated a preference for the use of capitalization instead of rate base?

A. Yes, the Commission stated:

> The capitalization of the utility is a better measure of the real cost of providing service since it is the cost of debt and equity that is reflected in the financial statements of the utility. To impute the operating income requirements based on an inflated rate base in effect establishes a cost of doing business that is non-existent to the utility.[6]

Q. Please compare the Companies' property-valuation methodologies.

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[4] *In the Matter of: The Application of Louisville Gas & Electric Company to Adjust and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-00080, Order at 7 (Ky. PSC Sept. 27, 2000).
[5] *Id.* at 9.
[6] *Id.* at 11.

A. For KU, Kentucky jurisdictional capitalization is $4,099,135,883 compared to rate base of $4,045,218,983. For LG&E's electric operations, capitalization is $2,593,434,547 compared to rate base of $2,548,077,150. Lastly, for LG&E's gas operations, capitalization is $788,382,061 compared to rate base of $775,283,637. A reconciliation of the two valuation amounts is located at Tab 13 as part of filing requirement 16(6)(f).

Q. Does capitalization remain the most objective measure of property valuation for the Companies?

A. Yes. The Companies believe capitalization remains the most objective measure of valuation given the Companies lack of unregulated activities. As the Commission has observed, while rate base and capitalization theoretically should be equal, it is rare that this happens.[7] When a utility's capitalization exceeds rate base, it raises concerns that a portion of the capitalization has been used to finance non-regulated activities.[8] For the Companies, though, that is not the case. This fact is confirmed by the Companies' recent nonregulated operations annual filings. Therefore, the Companies see no reason to change their valuation methodologies under these circumstances.

Q. Should the Commission extensively consider using the cost of reproduction as a going concern valuation methodology in this case?

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[7] *In the Matter of: Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of its Rate and Service*, Case No. 1998-00426, Order at 3 (Ky. PSC June 1, 1998).

[8] *In the Matter of: The Application of Louisville Gas & Electric Company to Adjust and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-00080, Order at 5 (Ky. PSC Sept. 27, 2000).

A. No. The Commission has consistently found such methodology was not the most appropriate or reasonable measure for rate of return valuation.[9] This methodology typically leads to a significantly higher revenue requirement than the capitalization or rate base methodologies.[10] Moreover, the United States Supreme Court has been critical of the use of this methodology for ratemaking purposes.[11] In light of this extensive precedent, the Companies believe presenting the reproduction methodology's results and raising the methodology's use as an issue for the

[9] *See, e.g.*, *General Adjustment of Rates of Kentucky Utilities Company*, Case No. 7804, Order at 2 (Ky. PSC Oct. 1, 1980) ("KU presented the net original cost, capital structure, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates and charges. As in the past, the Commission has given limited consideration to the proposed reproduction cost."); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 7799, Order at 6 (Ky. PSC Sept. 24, 1980) at 6 ("[A]s this [cost of reproduction] method is not conclusive to present value, the Commission, though recognizing this valuation as a lawful one, gave less consideration to it than to others it deemed would result in a more reasonable rate to the consumer and yet a reasonable rate of return to the investor"); *General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8177, Order at 9-10 (Ky. PSC Sept. 11, 1981); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8284, Order at 2 (Ky. PSC Jan. 4, 1982); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8616, Order at 4 (Ky. PSC March 2, 1983); *General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Order at 2 (Ky. PSC Mar. 18, 1983); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 3 (Ky. PSC May 16, 1984); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 3 (Ky. PSC May 16, 1984); *An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 15 (Ky. PSC June 30, 2004); *An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 17 (Ky. PSC June 30, 2004); *Application of Kentucky Utilities Company For An Adjustment of Electric Base Rates*, Case No. 2008-00251, Order at 16-17 (Ky. PSC Feb. 5, 2009); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 18 (Ky. PSC July 30, 2010).

[10] *See An Adjustment of the Rates of Elzie Neeley Gas Company*, Case No. 90-076, Order at 3 (Ky. PSC Dec. 7, 1990) (noting that reproduction cost appraisal inflates a utility's rate base, results in a valuation that has no economic substance, and could result in rates that are excessive in relation to the actual investment made by the owners of the utility). *See also The Application of Western Kentucky Gas Company For Authority to Adjust Its Rates*, Case No. 8227, Order at 3 (Ky. PSC Oct. 9, 1981) ("[N]et original cost, net investment and capital structure valuation methods are still the most prudent, efficient and economical measures of reasonable rate of return valuation.").

[11] *See, e.g., State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri*, 262 U.S. 276, 301 (1923) (Brandeis, J. concurring) ("[The] conviction is wide-spread that a sound conclusion as to the actual value of a utility is not to be reached by a meticulous study of conflicting estimates of the cost of reproducing new the congeries of old machinery and equipment, called the plant, and the still more fanciful estimates concerning the value of the intangible elements of an established business."). *See also St. Joseph Stock Yards Co. v. U.S.*, 298 U.S. 38 (1936); *Federal Power Commission v. Natural Gas Pipeline Co. of America*, 315 U.S. 575 (1942).

Commission's review and consideration in detail will not result in a productive or efficient use of the Commission's limited resources or those of any intervening party. The Commission's consideration of this evidence should be sufficient in light of this extensive precedent.

V. FORECASTED TEST PERIOD

Q. What is the forecasted test period the Companies used for supporting the requested increases in revenue for their operations in these cases?

A. The forecasted test period begins May 1, 2019, and ends April 30, 2020.

Q. What is the base period the Companies used for purposes of their base rate applications in these cases?

A. The base period is the 12-month period ending December 31, 2018, and consists of six months of actual data from January 1, 2018 to June 30, 2018, and six months of forecasted data from July 1, 2018 to December 31, 2018. KU and LG&E expect to file updated information, any corrections, and the actual data from July 1, 2018 to December 31, 2018 with the Commission no later than February 14, 2019 or 45 days after the end of the base period.

VI. CALCULATION OF JURISDICTIONAL REVENUE DEFICIENCY

Q. Have each of the Companies prepared jurisdictional financial summaries of their jurisdictional operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(a)?

A. Yes. Each of the Companies has prepared this information ("Schedule A"). Schedule A is located at Tab 54 to each application and shows how KU and LG&E determined the amount of the requested revenue increases for KU's jurisdictional operations and LG&E's electric and gas operations.

Q. Have you prepared a description of how the jurisdictional financial summary shown in Schedule A was prepared?

A. Yes. This description is shown in Appendix A – Rate Schedule to my testimony.

A. KU's Calculation of Revenue Deficiency

Q. What does KU's financial summary on Schedule A show?

A. The financial summary for KU's jurisdictional operations shows that KU's jurisdictional operations, at current rates, will incur a projected revenue deficiency of $112,663,325 for the forecasted test period, the 12-month period ending April 30, 2020. The projected revenue deficiency is based upon a required rate of return on capital of 7.56 percent. During the forecasted test period at current rates, KU's jurisdictional operations are projected to earn a rate of return of only 5.51 percent.

The revenue increase requested for KU's jurisdictional operations of $112,459,859 includes a revenue adjustment of ($199,767) as shown on Schedule M-2.1 to ensure that the under-recovery associated with the rate changes to the solar share and electric vehicle charging programs is not borne by other customers as discussed in the testimony of Mr. Seelye.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends December 31, 2018, KU's operations are expected to have a revenue deficiency of $26,219,603 and an earned rate of return on capital of 6.91 percent. The base period revenue deficiency is mitigated somewhat by favorable weather experienced in the first half of 2018 as shown in Mr. Sinclair's testimony. During the forecasted test period, the revenue deficiency for KU's jurisdictional operations is projected to increase and its earned rate of return on capital is projected to further decline.

B. LG&E Electric's Calculation of Revenue Deficiency

Q. What does LG&E's financial summary on Schedule A show for LG&E's electric operations?

A. The financial summary for LG&E's electric operations shows that LG&E's electric operations at current rates will incur a projected revenue deficiency of $34,975,012 for the forecasted test period, the 12-month period ending April 30, 2020. The projected revenue deficiency is based upon a required rate of return on capital of 7.62 percent. During the forecasted test period at current rates, LG&E's electric operations are projected to earn a rate of return of only 6.61 percent.

The revenue increase requested for LG&E's electric operations of $34,887,485 includes a revenue adjustment of ($90,078) as shown on Schedule M-2.1 to ensure that the under-recovery associated with the rate changes to the solar share and electric vehicle charging programs is not borne by other customers as discussed in the testimony of Mr. Seelye.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends December 31, 2018, LG&E's electric operations are expected to have a revenue surplus of $2,306,410 and an earned rate of return on capital of 7.44 percent. The base period revenue surplus is in part due to favorable weather experienced in the first half of 2018 as shown in Mr. Sinclair's testimony. During the forecasted test period, the revenue surplus abates and the revenue deficiency, discussed above, arises due to LG&E's projected investments in its electric operations.

C. LG&E Gas's Calculation of Revenue Deficiency

Q. What does LG&E's financial summary on Schedule A show for LG&E's gas operations?

A. The financial summary for LG&E's gas operations shows that LG&E's gas operations at current rates will incur a projected revenue deficiency of $24,925,739 for the forecasted test period, the 12-month period ending April 30, 2020. The projected revenue deficiency is based upon a required rate of return on capital of 7.62 percent. During the forecasted test period at current rates, LG&E's gas operations are projected to earn a rate of return of only 5.25 percent.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends December 31, 2018, LG&E's gas operations are expected to have a revenue deficiency of $15,885,883 and an earned rate of return on capital of 5.79 percent. During the forecasted test period, the revenue deficiency for LG&E's gas operations is projected to increase and its earned rate of return on capital is projected to further decline.

VII. JURISDICTIONAL RATE BASE SUMMARY

Q. Have the Companies each prepared a jurisdictional rate base summary of their utility operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(b)?

A. Yes. The Companies have each prepared Schedule B to satisfy the requirements of 807 KAR 5:001 Section 16(8)(b); these schedules are located at Tab 55 of each application. The information contained in Schedule B provides each company's net original cost rate base property as required under KRS 278.290. The calculated rate base amounts are for the base period and for a 13-month average for the forecasted test period as required by 807 KAR 5:001 Section 16(6)(c).

Q. Have you prepared a description of the components of Schedule B?

A. Yes. This description is shown in Appendix B – Rate Schedule to my testimony.

Q. Please explain the adjustments to base period and forecasted test period rate base shown in Schedule B-2.2.

A. Schedule B-2.2 removes from KU's and LG&E's rate base the portions of rate base for which the Companies' other rate mechanisms provide a recovery of and a return on the utility's investment. For KU and LG&E Electric, these mechanisms are the Demand Side Management ("DSM") cost-recovery mechanism and the Environmental Cost Recovery ("ECR") surcharge. For LG&E Gas, these mechanisms are the DSM cost-recovery mechanism and the Gas Line Tracker ("GLT").

Schedule B-2.2 further removes Asset Retirement Obligation ("ARO") assets from rate base, which is consistent with KU's and LG&E's approach in their prior base rate cases. In Case Nos. 2003-00426[12] and 2003-00427,[13] the Commission approved a stipulation that requested the Commission's approval for the following:

1) Approving the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;[14]

2) Eliminating the impact on net operating income in the 2003 ESM annual filing caused by adopting SFAS No. 143;

3) To the extent accumulated depreciation related to the cost of removal is recorded in regulatory assets or regulatory liabilities, reclassifying

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[12] *Application of Louisville Gas and Electric Company For An Order Approving An Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003*, Case No. 2003-00426, Order at 3 (Ky. PSC Dec. 23, 2003).

[13] *Application of Kentucky Utilities Company For An Order Approving An Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003*, Case No. 2003-00427, Order at 3 (Ky. PSC Dec. 23, 2003).

[14] The Financial Accounting Standards Board, which promulgates the U.S. Generally Accepted Accounting Principles, has renamed SFAS No. 143; it is now Accounting Standards Codification ("ASC") 410-20.

such amounts to accumulated depreciation for rate-making purposes of calculating rate base; and

4) Excluding from rate base the ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143.

In Case Nos. 2003-00433[15] and 2003-00434,[16] the Commission approved KU's and LG&E's proposed exclusion[17] of ARO assets from rate base. It again approved the exclusion in Case Nos. 2009-00548[18] and 2009-00549.[19] KU similarly excluded such amounts in Case Nos. 2016-00370,[20] 2014-00371,[21] 2012-00221[22] and 2008-00251,[23] which were resolved by Commission-approved settlements. LG&E similarly

[15] *An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 21 (Ky. PSC June 30, 2004).
[16] *An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 20-22 (Ky. PSC June 30, 2004).
[17] LG&E Response to Commission Staff's Third Set of Data Requests, Item No. 39 in *An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433 (Ky. PSC) (filed Mar. 11, 2004); KU Response to Commission Staff's Third Set of Data Requests, Item No. 39 in *An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434 (Ky. PSC) (filed Mar. 11, 2004).
[18] *Application of Kentucky Utilities Company For An Adjustment of Base Rates*, Case No. 2009-00548 (Ky. PSC July 30, 2010).
[19] *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates,* Case No. 2009-00549 (Ky. PSC July 30, 2010).
[20] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370 (Ky. PSC June 30, 2017).
[21] *Application of Kentucky Utilities Company For An Adjustment Its Electric Rates*, Case No. 2014-00371 (Ky. PSC June 30, 2015).
[22] *Application of Kentucky Utilities Company For An Adjustment of Its Electric Rates*, Case No. 2012-00221 (Ky. PSC Dec 20, 2012).
[23] *Application of Kentucky Utilities Company For An Adjustment of Electric Base Rates*, Case No. 2008-00251 (Ky. PSC Feb. 5, 2009).

excluded such amounts in Case Nos. 2016-00371,[24] 2014-00372,[25] 2012-00222[26] and 2008-00252,[27] which were resolved by settlements approved by the Commission.[28]

Q. Did KU conduct a jurisdictional separation study?

A. Yes. Mr. Seelye supervised the preparation of a Kentucky jurisdictional separation study for the forecasted test period that generated the Kentucky-jurisdictional allocation factors shown on Schedule B-7. The separation study includes updates to the allocation factors to reflect the termination of the municipal customers in April 2019 as discussed in the testimony of Mr. Bellar. These updates are shown on Schedule B-7.2 for the forecasted test period.

Q. In summary, what does Schedule B show?

A. For KU, Schedule B shows that KU's jurisdictional rate base for the base period will be $3,681,121,471 which will increase to a 13-month average of $4,045,218,983 for the forecasted test period. When the adjusted operating income shown in Schedule A for the forecasted test period of $225,740,344 is divided by the 13-month-average rate base for the same period, the result is that KU's utility operation will produce a rate of return on average rate base of 5.58 percent. If the Commission approves the requested increase and KU's utility operation earns its required operating income

[24] *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity,* Case No. 2016-00371 (Ky. PSC June 22, 2017).
[25] *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates,* Case No. 2014-00372 (Ky. PSC June 30, 2015).
[26] *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 (Ky. PSC Dec 20, 2012).
[27] *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates,* Case No. 2008-00252 (Ky. PSC Feb. 5, 2009).
[28] Asset retirement obligations associated with CCR closures are included as part of the Unamortized Closure Costs addition to rate base on Schedule B-6 and subsequently removed via the ECR rate base adjustment. CCR closure costs were approved for recovery through the ECR mechanism in Case Nos. 2016-00026 and 2016-00027.

shown in Schedule A for the forecasted test period of $309,857,872 it will earn a rate of return on average rate base of 7.66 percent.

For LG&E's electric operations, Schedule B shows that LG&E's rate base for its electric operations for the base period will be $2,380,526,725 which will increase to a 13-month average of $2,548,077,150 for the forecasted test period. Applying the adjusted operating income shown in Schedule A for the forecasted test period of $171,415,400 to the 13-month-average rate base for the same period produces a rate of return on average rate base of 6.73 percent for LG&E's electric operations. If the Commission approves the requested increase and LG&E's electric operations earns its required operating income shown in Schedule A for the forecasted test period of $197,563,876, it will earn a rate of return on average rate base of 7.75 percent.

For LG&E's gas operations, Schedule B shows that LG&E's rate base for the base period will be $732,534,958 which will increase to a 13-month average of $775,283,637 for the forecasted test period. Applying the adjusted operating income shown in Schedule A for the forecasted test period $41,422,432 to the 13-month-average rate base for the same period produces a rate of return on average rate base of 5.34 percent for LG&E's gas operations. If the Commission approves the requested increase and LG&E's gas operations earns its required operating income shown in Schedule A for the forecasted test period of $60,057,739 it will earn a rate of return on average rate base of 7.75 percent.

VIII. LEAD-LAG STUDIES

Q. Have KU and LG&E performed lead-lag studies?

A. Yes. The Companies performed three separate lead-lag studies for KU, LG&E Electric, and LG&E Gas. These lead-lag studies are sponsored by and attached to the testimony of William Steven Seelye, the managing partner for The Prime Group, LLC.

Q. Why did KU and LG&E perform lead-lag studies?

A. In the Stipulation and Recommendation entered into in Case Nos. 2016-00370 and 2016-00371, the Companies committed to filing a lead-lag study in their next base rate cases.[29] The Companies are filing these studies to comply with this commitment.

Q. Please describe the lead-lag studies.

A. The lead-lag studies were conducted to determine the allowance for cash working capital ("CWC") to be included in rate base. The lead-lag studies consist of two sections: the income statement analysis and the balance sheet analysis.

Q. Do the Companies accept the results of the lead-lag studies sponsored by Mr. Seelye?

A. Yes. Mr. Seelye utilized a methodology consistent with that used in KU's recent Virginia rate case filing.[30] The Companies note that Mr. Seelye's studies are principally focused on the income statement analyses of cash working capital. I am supporting the balance sheet analyses of cash working capital, which represent amounts from the Companies' forecast. Mr. Seelye explains the income statement analyses and the overall results of the lead-lag days in his testimony.

Q. What accounts were included in the balance sheet analyses of the cash working capital?

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[29] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Stipulation and Recommendation at Section 5.3 (Ky. PSC Apr. 19, 2017); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Stipulation and Recommendation at Section 5.3 (Ky. PSC Apr. 19, 2017).

[30] *Kentucky Utilities Company d/b/a Old Dominion Power Company For an Adjustment of Electric Base Rates*, Case No. PUR-2017-00106 (VSCC filed Sept. 29, 2017).

A. The balance sheet analyses included certain deferred debits and credits, miscellaneous liabilities, and pension and other employee benefit accounts not otherwise included in the income statement. The balance sheet analyses also include adjustments for capital expenditure accruals.

Q. Are there any key findings from the balance sheet analyses of cash working capital that you would like to discuss?

A. Yes. As shown on Schedule B-5.2, the balance sheet analyses show a Kentucky jurisdictional net cash working capital component for the forecasted test periods of $42,083,714 for KU, $87,262,950 for LG&E Electric, and $21,046,119 for LG&E Gas including the funding of the pension plan. Pension expense was included in the income statement analyses with an expense lead of zero days because it is a balance sheet item.

Q. Are the Companies using the results of the lead-lag studies to determine the cash working capital component of rate base?

A. Yes. In the Companies' prior base rate cases, the Companies have computed cash working capital on Schedule B-5.2 by using the 45-day (1/8) methodology.

IX. JURISDICTIONAL OPERATING INCOME SUMMARY

Q. Have the Companies each prepared a jurisdictional operating income summary of their operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(c)?

A. Yes. This information ("Schedule C") is located at Tab 56 to each application. LG&E has prepared a Schedule C for each of its utility operations.

Q. Briefly describe Schedule C.

A. Schedule C is a jurisdictional operating income summary for the base period and the forecasted test period with supporting schedules that are broken down by major account group and by individual account. It consists of four schedules:

- Schedule C-1 (Jurisdictional Operating Income Summary)
- Schedule C-2 (Jurisdictional Adjusted Operating Income Statement)
- Schedule C-2.1 (Jurisdictional Operating Revenues and Expenses By Account)
- Schedule C-2.2 (Comparison of Total Company Activity for KU and Comparison of Electric/Gas Utility Activity for LG&E)

A description of the components of Operations Schedules C-1, C-2, C-2.1 and C-2.2 are included in Appendix C – Rate Schedule to my testimony.

A. KU's Jurisdictional Operating Income Summary

Q. What does KU's Schedule C-1 show?

A. Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase by $112,459,859 for KU. This increase in revenue is equal to the amount of the "Revenue Increase Requested" reported on Schedule A. Expenses will increase by $28,494,245 for KU.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates. For the base period, KU projects total net operating income of $258,779,791, which results in a return on capitalization of 6.91 percent. Total net operating income during the forecasted test period is projected to decrease to $225,740,344. KU's rate of return on capitalization will decrease during the forecasted test period to 5.51 percent unless rates are increased.

B. LG&E Electric's Jurisdictional Operating Income Summary

Q. What does LG&E Electric's Schedule C-1 show?

A. Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase by $34,887,485 for LG&E Electric. This increase in revenue is equal to the amount of the "Revenue Increase Requested" reported on Schedule A. Expenses will increase by $8,804,447 for LG&E Electric.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates. For the base period, LG&E projects total electric net operating income of $183,311,097, which results in a return on capitalization of 7.44 percent. Total electric net operating income during the forecasted test period is projected to decrease to $171,415,400. LG&E Electric's rate of return on capitalization will decrease during the forecasted test period to 6.61 percent unless rates are increased.

C. LG&E Gas's Jurisdictional Operating Income Summary

Q. What does LG&E Gas's Schedule C-1 show?

A. Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase by $24,924,874 for LG&E Gas. This increase in revenue is equal to the amount of the "Revenue Increase Requested" reported on Schedule A. Expenses will increase by $6,290,213 for LG&E Gas.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates. For the base period, LG&E projects total gas net operating income of $43,576,924 which results in a return on capitalization of 5.79 percent. Total gas net operating income during the forecasted test period is projected to decrease to $41,422,432. LG&E Gas's rate of return on capitalization will decrease during the forecasted test period to 5.25 percent unless rates are increased.

X. JURISDICTIONAL ADJUSTMENTS TO OPERATING INCOME

Q. Have each of the Companies prepared jurisdictional adjustments to operating income by major account for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(d)?

A. Yes. This information ("Schedule D") with supporting schedules is located at Tab 57 to each of the applications. Schedule D provides the required comparisons between the base period and the forecasted test period. LG&E has prepared a Schedule D for each of its utility operations.

Q. Have you prepared a description of the components of Schedule D?

A. Yes. This description is shown in Appendix D – Rate Schedule to my testimony.

A. Effect of Certain Ratemaking Mechanisms on Requested Rate Increases

Q. What effect, if any, do ratemaking mechanisms such as the FAC, off-system sales adjustment clause ("OSS"), ECR, DSM, and GLT have on the base rate increases the Companies are requesting?

A. As discussed in my description of Schedule D, the impact of those mechanisms has been removed from the calculation of KU's and LG&E's operating revenues and expenses for both the base period ending December 31, 2018, and the forecasted test period ending April 30, 2020. The mechanisms and the costs and revenues associated with them, therefore, have no effect on the calculation of the revenue deficiency and corresponding base rate increases KU and LG&E are requesting in these cases. In addition, by removing these items from the calculation of net operating income in each Application, there is no double recovery of these costs or double counting of these revenues.

Q. What effect, if any, does the TCJA Surcredit have on the base rate increases the Companies are requesting?

A. The impacts of the TCJA have been incorporated into the base rate increases KU and LG&E are requesting and the TCJA Surcredit is no longer necessary as further explained in the testimony of Mr. Conroy and Mr. Blake.

B. KU's and LG&E Electric's Pro Forma Adjustments

Q. Do KU and LG&E Electric propose the same pro forma adjustments for their electric revenue requirements?

A. Yes. I detail each of the pro forma adjustments below. I discuss the pro forma adjustments for LG&E's gas revenue requirement separately.

1. DSM Adjustments

Q. Please explain the adjustment to operating revenues and expenses shown in Schedule D-2 that eliminates revenues recovered through the DSM mechanism and related expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate electric revenues to be recovered through the DSM mechanism and the corresponding expenses for both the base period and the forecasted test period.[31] The operating

[31] The Commission has previously reviewed and accepted adjustments for KU similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 22 (Ky. PSC June 30, 2004); *Application of Kentucky Utilities Company For An*

revenue and expense components of the adjustment are shown in the column labeled "Adj. 1 Remove DSM Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2.

Q. Please explain the adjustments shown in Schedule J-1.1/1.2 and Supporting Schedule B-1.1, which remove DSM rate base from KU's and LG&E's rate base and capitalization, respectively.

A. In accordance with the Commission's Orders in Case Nos. 2011-00134 and 2014-00003, the Companies capitalize the cost of installing load-control switches and related equipment used in two of its DSM programs, the Residential Load Management/Demand Conservation Program and the Commercial Load Management/Demand Conservation Program.[32] In accordance with the Commission's Order in Case No. 2014-00003, the Companies have previously capitalized the cost of advanced meters, related communications equipment, and other related capital items.[33] Because the Companies recover the cost of those investments,

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Adjustment of Base Rates, Case No. 2009-00548, Order at 18 (Ky. PSC July 30, 2010). In Case Nos. 2008-00251, 2012-00221, 2014-00371, and 2016-00370, base rate cases that were resolved by Commission–approved settlement agreements, KU also proposed similar adjustments. The Commission has also previously reviewed and accepted adjustments for LG&E similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 24-25 (Ky. PSC June 30, 2004); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 19-20 (Ky. PSC July 30, 2010). In Case Nos. 2008-00252, 2012-00222, 2014-00372, and 2016-00371, base rate cases that were resolved by Commission-approved settlement agreements, LG&E also proposed similar adjustments.

[32] *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 at 14 (Ky. PSC Nov. 9, 2011) ("The Companies' request to add a fifth element to the DSMRC to account for the capital expenditure needed to develop the Residential and Commercial Load Management/Demand Conservation Program in the DSM/EE Program Plan is granted."); *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 (Ky. PSC Nov. 14, 2014).

[33] *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 (Ky. PSC Nov. 14, 2014).

as well as a return on those investments, through the DSM mechanism, column 4 of Supporting Schedule B-1.1 removes DSM rate base from each company's rate base and column H for KU and column F for LG&E Electric of page 1 of Schedule J-1.1/1.2 removes DSM rate base and other mechanism-related rate base from each company's capitalization. These adjustments were performed using a methodology similar to that used in the Companies' three most recent base rate cases, all of which were resolved by Commission-approved settlement agreements.

2. FAC Adjustment

Q. Please explain the adjustment to operating expenses and revenues to eliminate the FAC revenues shown in Schedule D-2.

A. Consistent with past Commission practice in KU's and LG&E's prior base rate cases, this adjustment eliminates the difference between fuel expenses and base fuel revenues. The operating revenue and expense components of the adjustment for both the base period and the forecasted test period are shown in the column labeled "Adj. 3 Remove FAC Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2.[34]

3. OSS Adjustment

[34] The Commission has previously reviewed and accepted adjustments for KU similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 22 (Ky. PSC June 30, 2004); *Application of Kentucky Utilities Company For An Adjustment of Base Rates*, Case No. 2009-00548, Order at 18 (Ky. PSC July 30, 2010). In Case Nos. 2008-00251, 2012-00221, 2014-00371, and 2016-00370, base rate cases that were resolved by Commission–approved settlement agreements, KU also proposed similar adjustments. The Commission has previously reviewed and accepted adjustments for LG&E similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 24-25 (Ky. PSC June 30, 2004); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 19-20 (Ky. PSC July 30, 2010). In Case Nos. 2008-00252, 2012-00222, 2014-00372, and 2016-00371, base rate cases that were resolved by Commission-approved settlement agreements, LG&E proposed a similar adjustment.

Q. Please explain the adjustment to operating expenses and revenues to eliminate OSS revenues, OSS mechanism revenues, and OSS expenses shown in Schedule D-2.

A. In Case Nos. 2014-00371 and 2014-00372, the Commission ordered that an OSS adjustment clause be implemented under which electric OSS margins would be shared on a 75 percent - 25 percent basis between customers and the Companies, respectively. The Commission further ordered that OSS margins attributable to customers (seventy-five percent) be flowed through the FAC.

Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate OSS revenues, OSS mechanism revenues, and OSS expenses included in the forecasted test period. The operating revenue and expense component of the adjustment for the base period and the forecasted test period are shown in the column labeled "Adj. 4 Remove OSS Mechanism" of Schedule D-2. Supporting details are contained in WPD-2. OSS revenues and expenses will continue to be addressed through the OSS mechanism after the implementation of new base rates. This treatment is consistent with the Companies' treatment in their last base rate cases, Case Nos. 2016-00370 and 2016-00371.

4. ECR Adjustments

Q. Please explain the adjustment to operating expenses and revenues to eliminate ECR revenues and expenses shown in Schedule D-2.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate ECR revenues and expenses during the forecasted test period that will continue to be included through the ECR mechanism after the implementation of new base rates. The operating revenue and expense components of the adjustment for both the base period and the forecasted test period are shown in the column labeled "Adj. 2 Remove ECR Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2. The ECR surcharge is provided for full recovery of approved environmental costs that qualify for the surcharge.

In regards to the ECR expense adjustment discussed above, KU is proposing to eliminate the baseline ECR beneficial reuse operating expense credit currently included in the ECR mechanism when new base rates take effect as part of this proceeding. Prior to this proposal, only those ECR beneficial reuse expenses or savings which exceeded or fell below the baseline amount were recoverable or refundable through the ECR mechanism. With the implementation of new base rates in this proceeding, the baseline adjustment is no longer necessary and all beneficial reuse savings and costs will be included in the ECR mechanism. The baseline credit currently included in base rates prior to this change is $440,000 for the Ghent facility.

Consistent with the Commission's Orders in Case Nos. 2009-00310 and 2009-00311 approving the use of the revenue requirement method for calculating the monthly ECR billing factor, the Companies are removing all ECR revenues collected in the environmental surcharge and in base rates.[35] The removal of ECR revenues from base rates is necessary to ensure base revenues reflect only base rate

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[35] *An Examination By The Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Electric Company for the Two-Year Billing Period Ending April 30, 2009*, Case No. 2009-00310 (Ky. PSC Dec. 2, 2009); *An Examination By The Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Two-Year Billing Period Ending April 30, 2009*, Case No. 2009-00311 (Ky. PSC Dec. 2, 2009).

components and costs are recovered through the appropriate rate-making mechanism. KU proposed such an adjustment using this methodology in Case Nos. 2012-00221, 2014-00371, and 2016-00370, all of which were resolved by Commission-approved settlement agreements. LG&E proposed such an adjustment using this methodology in Case Nos. 2012-00222, 2014-00372, and 2016-00371, all of which were resolved by Commission-approved settlement agreements.

Q. Please explain the adjustment to operating revenues shown in Schedule D-2.1 that concerns OSS revenues related to the ECR calculation.

A. In determining the monthly ECR surcharge, a portion of KU's and LG&E's environmental compliance costs are allocated to OSS, including intercompany sales, through the jurisdictional allocation ratio. Because total ECR expenses are removed through the adjustment in Schedule D-2, the expenses associated with off-system and intercompany sales are understated. This results in a mismatch of the revenues and expenses related to the off-system and intercompany sales portion of the allocated environmental surcharge monthly revenue requirement. The Companies have included in this adjustment a reduction to electric revenues associated with ECR-related off-system and intercompany sales revenues. The electric operating revenue components of this adjustment are shown in the column labeled "Adj. 6 ECR for Off-System Sales" of Schedule D-2.1. The supporting details are contained in Schedule WPD-2.1.

KU performed the adjustment in a manner generally consistent with the methodology used in Case Nos. 2009-00548, 2012-00221, 2014-00371, and 2016-00370. The Commission found the adjustment reasonable in Case No. 2009-00548.

Case Nos. 2012-00221, 2014-00371, and 2016-00370 were resolved by Commission-approved settlement agreements.

LG&E performed the adjustment in a manner generally consistent with the methodology used in Case Nos. 2009-00549, 2012-00222, 2014-00372, and 2016-00371. The Commission found the adjustment reasonable in Case No. 2009-00549. Case Nos. 2012-00222, 2014-00372, and 2016-00371 were resolved by Commission-approved settlement agreements.

Q. Please explain the adjustments shown in Schedule J-1.1/1.2 and Supporting Schedule B-1.1, which remove ECR rate base from the Companies' rate base and capitalization, respectively.

A. Removing KU's and LG&E's ECR rate base from their capitalization and rate base is necessary because each company is recovering its investment, as well as a return on its investment, through the ECR mechanism. Column 3 of Supporting Schedule B-1.1 removes ECR rate base from KU's and LG&E's rate base and Column H for KU and Column F for LG&E Electric of page 1 of Schedule J-1.1/1.2 removes ECR rate base and other mechanism-related rate base from KU's and LG&E's capitalization.

KU performed these adjustments using a methodology the Commission approved in Case Nos. 2009-00548 and 2003-00434 and KU proposed in Case Nos. 2016-00370, 2014-00371, 2012-00221 and 2008-00251, which were resolved by Commission-approved settlement agreements.

LG&E performed these adjustments using the methodology that the Commission approved in Case Nos. 2009-00549, 2003-00433, 98-426 and that

LG&E also proposed in Case Nos. 2016-00371, 2014-00372, 2012-00222, and 2008-00252, which were resolved by settlement agreements.

5. Interest Synchronization Adjustment

Q. Please explain the adjustment shown in Schedule D-2 labeled "Adj 5 Interest Synchronization."

A. This adjustment is for federal and state income taxes corresponding to the adjustment of interest expense. The Commission has historically recognized the income tax effects of adjustments to interest expense through an "interest synchronization" adjustment. Income tax expense is adjusted to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the other rate mechanisms, predominantly the ECR surcharge. The interest expense included in KU's and LG&E's "Jurisdictional Adjusted Capital" is computed from Schedule J-1.1/J-1.2 Column L for KU and Column J for LG&E Electric and that amount is then compared to KU's and LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate is then applied to the interest synchronization amount. The supporting details are contained in Schedule WPD-2. The Companies performed the adjustment consistent with the methodology used in their last base rate cases, Case Nos. 2016-00370, 2016-00371, 2014-00371, and 2014-00372.

C. LG&E Gas's Pro Forma Adjustments

1. DSM Adjustment

Q. Please explain the adjustment to gas operating revenues and expenses shown in Schedule D-2 for gas operations that eliminates revenues recovered through the DSM mechanism and related expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers,[36] an adjustment was made to eliminate gas revenues to be recovered through the DSM mechanism and the corresponding expenses for both the base period and the forecasted test period. The gas operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 1 Remove DSM Mechanism" of Schedule D-2 for gas operations. The supporting details are contained in Schedule WPD-2 for gas operations.

2. GSC Adjustment

Q. Please explain the adjustment to gas operating revenues and expenses shown in Schedule D-2 for gas operations that eliminates GSC recoveries and expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, this adjustment eliminates the effect of GSC recoveries and gas supply expenses for both the base period and the forecasted test period. The gas operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 3 Remove GSC Mechanism" of Schedule D-2 for gas operations. The supporting details are contained in Schedule WPD-2 for gas operations.

The Commission determined a similar adjustment to be reasonable in Case No. 2009-00549. LG&E proposed a similar adjustment in Case Nos. 2003-00433,

[36] The Commission has previously reviewed and accepted adjustments similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 24-25 (Ky. PSC June 30, 2004); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 19-20 (Ky. PSC July 30, 2010). In Case Nos. 2008-00252, 2012-00222, and 2014-00372, base rate cases that were resolved by Commission-approved settlement agreements, LG&E also proposed a similar adjustment.

2008-00252, 2012-00222, 2014-00372, and 2016-00371 which were resolved by Commission-approved settlement agreements.

3. GLT Adjustments

Q. Please explain the adjustment to gas operating revenues and expenses shown in Schedule D-2 for gas operations that eliminates GLT revenues and expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, LG&E has eliminated revenues to be recovered through the GLT and the corresponding expenses for both the base period and the forecasted test period.[37] The gas operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 2 Remove GLT Mechanism" of Schedule D-2 for gas operations. The supporting details are contained in Schedule WPD-2 for gas operations.

In regards to the GLT expense adjustment discussed above, LG&E is proposing to eliminate the baseline GLT operating expense adjustment currently included in the GLT mechanism when new base rates take effect as part of this proceeding. Prior to this proposal, only those GLT operating expenses associated with the main and riser replacement programs which exceeded or fell below the baseline amount were recoverable or refundable through the GLT mechanism. With the main and riser replacement programs completed, operating expenses reflect the savings realized through the programs, making the baseline adjustment no longer necessary.

[37] This adjustment is similar to the DSM revenue and expense elimination adjustment that the Commission has previously found to be reasonable and that LG&E has proposed in its five most recent base rate cases. In Case No. 2016-00371, which was resolved by Commission-approved settlement agreement, LG&E proposed the same adjustment regarding GLT revenues and expenses as proposed in its current application.

Q. Please explain the adjustments shown in Schedule J-1.1/1.2 for gas operations and Supporting Schedule B-1.1 for gas operations that remove GLT rate base from LG&E's gas rate base and capitalization, respectively.

A. Removing LG&E's GLT rate base from its gas capitalization and rate base is necessary because LG&E is recovering its investment, as well as a return on its investment, through the GLT mechanism. Therefore, Column 10 of Supporting Schedule B-1.1 for gas operations removes GLT rate base from LG&E's gas rate base, and Column F of page 2 of Schedule J-1.1/1.2 for gas operations removes GLT rate base and other mechanism-related rate base from LG&E's gas capitalization. Removing GLT rate base from LG&E's gas capitalization and rate base is consistent with the removal of DSM rate base, which I describe above, and with the adjustment that LG&E proposed in Case Nos. 2014-00372[38] and 2016-00371.[39]

4. Interest Synchronization Adjustment

Q. Please explain the adjustment shown in Schedule D-2 for gas operations labeled "Adj. 5 Interest Synchronization."

A. This adjustment is for federal and state income taxes corresponding to the adjustment of interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an "interest synchronization" adjustment. Income tax expense is adjusted to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the other rate mechanisms, predominantly the GLT. The interest expense included in LG&E's "Jurisdictional Adjusted Capital" is computed from Schedule J-

[38] *See* Case No. 2014-00372, Testimony of Robert M. Conroy at 16 (filed Nov. 26, 2014).
[39] *See* Case No. 2016-00371, Testimony of Christopher M. Garrett at 36 (filed Nov. 23, 2016).

1.1/J-1.2 Column J and that amount is then compared to LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate is then applied to the interest synchronization amount. The supporting details are contained in Schedule WPD-2. LG&E performed the adjustment consistent with the methodology used in its last base rate case, Case No. 2016-00371.

D. Non-Mechanism-Related Adjustments

1. Advertising Expenses

Q. Please explain the adjustment to electric and gas operating expenses shown in the column labeled "Adj. 8 Advertising Expenses" on Schedule D-2.1.

A. This adjustment eliminates *all* institutional and promotional advertising expenses. Commission regulation 807 KAR 5:016 Section 2(1) provides that a utility will be allowed to recover, for ratemaking purposes, only those advertising expenses that produce a "material benefit" for its ratepayers. The Companies removed all institutional and promotional advertising expenses in their last base rate cases, Case Nos. 2016-00370 and 2016-00371.

XI. JURISDICTIONAL FEDERAL AND STATE INCOME TAX SUMMARY

Q. Have the Companies prepared jurisdictional federal and state income tax summaries for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(e)?

A. Yes. This information ("Schedule E") is located in Tab 58 to the application. A Schedule E was prepared for KU, LG&E Electric, and LG&E Gas.

Q. Please describe Schedule E.

A. Schedule E has two parts: Schedule E-1 shows the company's jurisdictional income tax at current rates for the base period and shows pro forma adjustments at both current and proposed rates for the forecasted test period; Schedule E-2 shows how the jurisdictional allocation was derived. This allocation was based on the same methodology KU and LG&E have historically used in their base rate cases, and is unchanged from their last rate cases, Case No. 2016-00370 and Case No. 2016-00371.

The effective tax rate, computed as "Total Income Taxes" per row 113 for KU, row 111 for LG&E Electric, and row 103 for LG&E Gas, divided by "Book Net Income before Income Tax & Credits" per row 3, is 20.4 percent for the base period and 14.8 percent for the pro forma forecasted test period for KU, 19.7 percent for the base period and 17.2 percent for the pro forma forecasted test period for LG&E Electric, and 20.8 percent for the base period and 17.7 percent for the pro forma forecasted test period for LG&E Gas.

Q. Do the Companies' rates reflect the changes caused by recent federal and state tax reform?

A. Yes. The Companies' rates incorporate both federal and state tax reform. The Companies have considered the reduced income tax expense and the excess deferred tax amortization in developing the revenue requirement in this proceeding. The Companies have also updated the gross revenue conversion factors for the lower tax rates.

Q. Briefly describe the recent federal tax reform.

A. The TCJA was enacted on December 22, 2017. The TCJA reduces the maximum federal corporate income tax rate from 35% to 21% effective January 1, 2018 and also includes other changes which will impact the Companies, including the elimination of bonus depreciation and the corporate alternative minimum tax ("AMT") provision and the repeal of various other deductions including the Section 199 domestic manufacturing deduction. The TCJA retains the corporate deduction for state income taxes and the interest deductibility for utilities, and provides modifications for how companies can still utilize net operating losses and existing AMT credit carryforwards. The Companies began providing the TCJA Surcredit to distribute the base rate benefits of the TCJA to customers on April 1, 2018, and will continue to do so through April 30, 2019. The TCJA Surcredit is set to expire on April 30, 2019 because the tax benefits from the TCJA are being incorporated into base rates as discussed above per the terms of the Offer and Acceptance of Satisfaction approved in the March 20, 2018 Order in Case No. 2018-00034 .

Q. Briefly describe the recent state tax reform.

A. The 2018 Kentucky General Assembly adopted two bills which make substantial changes to Kentucky's tax code. House Bill ("H.B.") 366 (which was adopted in its entirety in H.B. 487) and H.B. 487 make a number of changes to Kentucky's income taxes and sales and use taxes as well as reforms aimed at simplifying compliance with the administration of Kentucky's tax statutes.

H.B. 487 reduces the generally applicable corporate and individual income tax rates, makes certain changes to the corporate and individual income tax bases, and adopts single sales factor apportionment for multistate companies. Prior to the implementation of H.B. 487, the Companies paid a state corporate income tax rate of 6%. For taxable years beginning on or after January 1, 2018, the state corporate income tax will be imposed at a 5% tax rate.[40]

Q. How are the Companies accounting for the reduction in the Kentucky state corporate income tax rate?

A. In a separate filing earlier this month, the Companies requested permission to establish regulatory liabilities by the end of the year for the excess accumulated deferred income taxes ("ADIT") created by the reduction in the state corporate income tax rate.[41]

Like the Companies' treatment of the TCJA, KU and LG&E will account for the state corporate tax rate reduction by amortizing all protected excess ADIT using the Average Rate Assumption Method ("ARAM") and amortizing all unprotected excess ADIT over a 15-year amortization period. The Companies will continue to treat all property-related excess ADIT as protected. The amortization of the unprotected excess ADIT will begin when new base rates go into effect.

XII. GROSS REVENUE CONVERSION FACTOR

Q. Have the Companies each prepared a computation of a gross revenue conversion factor for the forecasted test period as required by 807 KAR 5:001 Section 16(8)(h)?

A. Yes. This information ("Schedule H") is located at Tab 61 to each application. LG&E has prepared separate Schedule Hs for its electric and gas operations.

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[40] H.B. 366 at sec. 58, amending KRS 141.040. H.B. 487 incorporates the entirety of H.B. 366.

[41] *Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving the Establishment of Regulatory Liabilities and Regulatory Assets*, Case No. 2018-00304 (Ky. PSC filed Sept. 10, 2018).

Q. Please describe Schedule H.

A. Each Schedule H sets forth the calculation of the gross revenue conversion factor ("GRCF"). This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. The use of a GRCF is a long-standing practice in calculating the revenue requirement. This factor is designed to cover income taxes, uncollectible accounts expense and revenue-based fees assessed by the Commission on the requested revenue increase. The federal and state income tax rates are calculated as shown in the attached Workpaper WPH-1.A at Tab 61. The uncollectible accounts expense rate of 0.32 percent for KU and 0.18 percent for LG&E is based on the historic 5-year average. The rate used for the KPSC assessment fee is based on the last assessment notice received by the Companies. The GRCF is used to compute the respective calculated revenue deficiency based on the associated calculated net operating income deficiency.

XIII. COMMON REGULATORY ASSETS AND LIABILITIES

Q. Are the Companies proposing modifications to regulatory assets or liabilities in this case?

A. Yes, they are. These updates to existing regulatory assets and liabilities are described below.

A. Scheduled Outages

Q. Please describe the generator outage expenses that are included in the Companies' revenue requirements.

A. The Companies propose to continue the use of an eight-year average of generator outage expenses in their revenue requirements consistent with the ratemaking treatment from their last base rate cases.[42] Historical expenses for years 2015 through 2018 and forecasted expenses for years 2018 through 2022 were utilized to develop the eight-year average outage expense included in the forecasted test year.[43] As discussed in the last base rate cases, generator outage expenses can fluctuate significantly from year to year and major outages typically occur on an eight-year cycle.

Q. Do the Companies currently have regulatory assets or liabilities associated with the generator outages from their last base rate cases?

A. Yes. As of April 30, 2019, KU forecasts a $1.9 million jurisdictional regulatory liability associated with generator outage expense. As of April 30, 2019, LG&E forecasts a $7.3 million regulatory asset associated with the scheduled outages.

Q. How do the Companies plan to recover or distribute the generator outage regulatory asset and regulatory liability?

A. KU and LG&E are proposing to amortize the $1.9 million regulatory liability and $7.3 million regulatory asset over an eight-year period with amortization beginning when new base rates take effect. The eight-year period is consistent with the eight-year major outage cycle.

B. State Tax Reform

Q. Describe the Companies' requested regulatory liability treatment related to state tax reform.

[42] Case No. 2016-00370 and Case No. 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

[43] 2018 includes six months of actual (January-June) and six months of forecasted (July-December) outage expense.

A. As I previously mentioned, in a separate filing earlier this month,[44] the Companies requested permission to establish regulatory liabilities by the end of the year for the excess ADIT created by the reduction in the state corporate income tax rate. Included in the forecasted test year is approximately $1.0 million for KU, $0.5 million for LG&E Electric, and $0.1 million for LG&E Gas of additional excess ADIT amortization associated with Kentucky state tax reform.

C. Storm Damage

Q. Describe the Companies' requested regulatory asset treatment related to the storms beginning July 20, 2018.

A. In addition to the regulatory liability treatment for state tax reform discussed above, the Companies also requested permission to establish regulatory assets by the end of the year to authorize the Companies to accumulate and defer for future recovery the incremental costs the Companies incurred to repair damage and restore service to customers following the storm that impacted the Companies' service territories beginning on July 20, 2018 in Case No. 2018-00304.[45] Current estimates for the regulatory assets are $4.7 million for KU and $2.4 million for LG&E. The Companies are requesting these costs be amortized over a five-year period beginning when new rates take effect from this proceeding. The five-year amortization period is consistent with previous cases involving significant storm damages.[46]

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[44] *Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving the Establishment of Regulatory Liabilities and Regulatory Assets*, Case No. 2018-00304 (Ky. PSC filed Sept. 10, 2018).
[45] *Id.*
[46] *See, e.g., In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 40 (Ky. PSC June 30, 2004) ("Given the nature and significance of the event, the Commission believes that KU's proposal to defer and amortize over 5 years the February 2003 ice storm is reasonable.").

Q. Are the Companies requesting to change the amortization periods for the 2009 Winter, 2008 Wind, and 2011 Summer storms in this proceeding?

A. Yes. The amortization period for the Winter Storm 2009 and Wind Storm 2008 Regulatory Assets are set to end in July 2020. The annual amortization expense for these regulatory assets is approximately $5.9 million for KU and $6.7 million for LG&E. The Companies are requesting to extend the amortization period to June 2021 to avoid a large over recovery of costs given the magnitude of these particular storm regulatory assets. The requested schedule extension reduces the annual amortization to $3.4 million for KU and $3.9 million for LG&E, thus lowering the revenue requirements by $2.5 million for KU and $2.8 million for LG&E.

In Case Nos. 2016-00370 and 2016-00371, LG&E and KU were authorized to allow shorter-lived regulatory assets including those associated with the 2011 LG&E Summer Storm to be credited for the amounts collected through base rates even if such amortization resulted in changing such a regulatory asset to a regulatory liability with any remaining balances being addressed in the next base rate case.[47] As a result, in the prior rate case, LG&E included $0.8 million of regulatory *asset* amortization; and in the current proceeding, LG&E has included $0.3 million of regulatory *liability* amortization.

As part of this proceeding, LG&E requests to amortize the regulatory liability for the 2011 Summer Storm through June 2021 consistent with regulatory treatment

[47] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Stipulation and Recommendation at Section 5.1 (Ky. PSC Apr. 19, 2017); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371, Stipulation and Recommendation at Section 5.1 (Ky. PSC Apr. 19, 2017).

of the winter and wind storms discussed above. The requested change reduces the revenue requirement for LG&E Electric by $1.1 million.

XIV. KU-SPECIFIC REGULATORY ASSET

Q. Is there a regulatory asset request specific to KU?

A. Yes. KU seeks regulatory asset treatment associated with the retirement of E.W. Brown Generating Station ("Brown") Units 1 and 2.

Q. When does KU plan to retire Brown Units 1 and 2?

A. On November 14, 2017, KU announced its plans to retire Brown Units 1 and 2 by February 2019.

Q. Please describe the accounting treatment KU is requesting for the retirement of Brown Units 1 and 2.

A. KU seeks regulatory asset treatment for $1.9 million in remaining Kentucky jurisdictional inventory values of Brown Units 1 and 2 consistent with the regulatory treatment provided for the closure of Green River.[48] Due to the age, size, and type of operating equipment in these units, the majority of the inventory cannot be used on other units in the fleet nor is there a viable market for selling the inventory. KU requests this regulatory asset be amortized over three years, consistent with the amortization period allowed for the retirement of Green River, beginning with the effective date of the new base rates.

XV. STEAM GENERATION PLANT DEPRECIATION RATES

Q. Have the Companies updated their electric steam depreciation rates?

[48] Case No. 2014-00372, Settlement Agreement, Stipulation, and Recommendation at Article I, Section 1.5 (Ky. PSC Apr. 20, 2015).

A. Yes, they have. KU and LG&E engaged Mr. John Spanos of Gannett Fleming, Inc. to update their electric steam depreciation rates.

Q. Why did KU and LG&E choose Mr. Spanos of Gannett Fleming, Inc. to update its depreciation rates?

A. Mr. Spanos has extensive experience in the regulated utility accounting field, and particularly in the area of depreciation rates. Mr. Spanos is a member of the Society of Depreciation Professionals, and has submitted testimony to over twenty-five regulatory commissions on the subject of utility plant depreciation. He has previously prepared depreciation studies for KU and LG&E that were presented to the Commission in numerous cases for more than ten years.[49]

Q. What did the Companies ask Mr. Spanos to do?

A. The Companies asked Mr. Spanos to perform an independent depreciation study, using data from historical records of KU's and LG&E's electric steam generation plant, his generation asset life assessment analysis of the Companies' assets, and his extensive experience in depreciation studies. The purpose of the study was to evaluate KU's and LG&E's electric steam generation depreciation rates and, if

[49] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370 (Ky. PSC filed Nov. 23, 2016); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity,* Case No. 2016-00371 (Ky. PSC filed Nov. 23, 2016); *Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Depreciation Rates For Brown Solar*, Case No. 2016-00063 (Ky. PSC filed Jan. 29, 2016); *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2014-00371 (Ky. PSC filed Nov. 26, 2014); *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2014-00372 (Ky. PSC filed Nov. 26, 2014); *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2012-00221 (Ky. PSC filed June 29, 2012); *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 (Ky. PSC filed June 29, 2012); *Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565 (Ky. PSC filed Dec. 28, 2007); *Application of Louisville Gas and Electric Company to File Depreciation Study*, Case No. 2007-00564 (Ky. PSC filed Dec. 28, 2007).

necessary, recommend updated depreciation rates to reflect the actual deprecation of KU's and LG&E's assets.

Q. Why did KU and LG&E ask Mr. Spanos to review their depreciation rates so shortly after having filed a depreciation study in their last rate cases?

A. As discussed in the testimony of Mr. Blake, given the recent announcement regarding the retirement of Brown Units 1 and 2 along with the aging coal fleet, the Companies felt it was appropriate that their steam depreciation rates be updated to help avoid future intergenerational inequities.

Q. What did Mr. Spanos find and recommend?

A. Mr. Spanos found that KU's and LG&E's current electric steam depreciation rates need to be updated to fully reflect the current or actual depreciation of KU's and LG&E's assets. Mr. Spanos' study reflects an increase in depreciation rates as a result of the Companies' announced retirements of Brown Units 1 and 2 in February 2019 and the fact that most of the Companies' coal-fired generation is expected to be economically retired by 2050.[50]

Q. Did the Companies accept Mr. Spanos's recommendation for updated electric steam depreciation rates?

A. Yes. The Companies accepted Mr. Spanos's recommendation for updated electric steam depreciation rates. These updated depreciation rates were used to develop the revenue requirements.

[50] PPL Corporation, *PPL Corporation Climate Assessment*, Potential LG&E and KU Generation Mix (Figure 18) at p. 14, https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf (November 2017).

XVI. <u>CONCLUSION</u>

Q. Do you have any recommendations for the Commission?

A. Yes. I recommend that the Commission: (1) approve the Companies' requested rates; (2) authorize KU to create a regulatory asset and amortize the remaining inventory values of Brown Units 1 and 2; (3) include the amortization amounts from the regulatory liabilities for state tax reform and regulatory assets for costs related to the July 2018 storm in the calculation of the KU and LG&E revenue requirements; and (4) accept and approve the electric steam depreciation rates set forth in Mr. Spanos' depreciation study.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of September 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

Christopher M. Garrett

Controller
Louisville Gas and Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3328

Previous Positions:

Director, Rates	Feb 2016 – Dec 2017
Director, Accounting and Regulatory Reporting	Dec 2012 – Jan 2016
Director, Financial Planning & Controlling	Feb 2010 – Nov 2012
Manager, Financial Planning	Nov 2007 – Feb 2010
Manager, Corporate Accounting	Jan 2006 – Oct 2007
Manager, Utility Tax	May 2002 – Jan 2006
Tax Analyst, various positions	Aug 1995 – May 2002

Education:

Eastern Kentucky University, Bachelor of Business Administration - Accounting, 1995
Graduated Magna Cum Laude
Certified Public Accountant, Kentucky, 1999

Professional Memberships:

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KSCPA)
Edison Electric Institute

Civic Activities:

The Louisville Free Public Library Foundation
St. Joseph School - Tuition Administration Committee

APPENDIX A – RATE SCHEDULE

Schedule A

To prepare the jurisdictional financial summary shown in Schedule A, each of the Companies first determined the amount of required operating income. For KU's required operating income, KU multiplied the required rate of return by the total capital allocated to KU's jurisdictional operations for the forecasted test period. For LG&E's required operating income for electric operations, LG&E multiplied the required rate of return by the total capital allocated to LG&E's electric operations for the forecasted test period. LG&E performed the same calculation for its gas operations. The total allocated capital and required rate of return are obtained from the cost of capital summary required by 807 KAR 5:001 Section 16(8)(j) ("Schedule J"). Total adjusted operating income produced by each company's present rates, which is found in the jurisdictional operating income summary required by 807 KAR 5:001 Section 16(8)(c) ("Schedule C"), is then subtracted from the total required operating income. The difference is then multiplied by the gross revenue conversion factor, whose computation is required by 807 KAR 5:001 Section 16(8)(h) ("Schedule H"), which takes into account the effects of various state and federal income taxes and bad debt expense. This product represents the additional revenues that each company's operations require to meet each company's reasonable operating expenses and earn a reasonable rate of return. When these additional revenues are added to adjusted operating revenues in the forecasted test period per Schedule C-1, the sum represents each company's revenue requirement for the forecasted test period. These calculations were performed for KU, LG&E Electric, and LG&E Gas.

APPENDIX B – RATE SCHEDULE

Schedule B

Schedule B consists of a summary schedule, Schedule B-1, showing each company's calculated rate base for the base period and the forecasted test period. The information contained in Schedule B-1 derives from the remaining schedules in Schedule B, which calculate the rate base components and adjustments: Plant in Service (Schedules B-2 – B-2.7), Accumulated Depreciation and Amortization (Schedules B-3 – B-3.2), Construction Work in Progress (Schedule B-4 – B-4.2), Allowance for Working Capital (Schedules B-5 – B-5.2), Deferred Credits and Accumulated Deferred Income Taxes (Schedule B-6), and Jurisdictional Percentages (Schedules B-7 – B-7.2). Schedule B-8 provides comparative balance sheets for calendar years 2013-2017, as well as for the base period and for a 13-month average for the forecasted test period.

APPENDIX C – RATE SCHEDULE

Schedule C-1

Each Schedule C-1 summarizes KU's, LG&E Electric's, and LG&E Gas's jurisdictional operating revenues and expenses for each utility's operations for the base and forecasted test periods. The schedule depicts the base period level (Column 1), forecasted test period level at current rates (Column 3), and forecasted test period levels at the proposed rates (Column 5).

The amounts set forth in each Schedule C-1, Column 1 reflect that utility's adjusted base period amounts.[51] These amounts represent base year totals adjusted to remove revenues and expenses associated with the mechanisms as these represent revenues and costs recovered outside of base rates.[52] In addition, an interest synchronization adjustment is made to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the rate mechanisms. The removal of these revenues and expenses is shown on Schedule D-2.

The adjustments in Schedule C-1, Column 2 are detailed in Schedule D-1.

Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. The increases in expenses reflect the changes in income taxes, bad debt expenses (included in "Operation and Maintenance Expenses"), and KPSC assessment fees (included in "Taxes Other Than Income") related to the increased revenues. The proposed increase in "Net Operating Income"[53] is equal to the Operating Income Deficiency reported in Schedule A.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates.

Schedule C-2

<u>KU and LG&E Electric</u>
For KU and LG&E Electric, Schedule C-2 details each utility's adjusted jurisdictional operating income statement for the base period and the forecasted test period as used in Columns 1 and 3 of Schedule C-1, and breaks down "Forecasted Adjustments at Current Rates" per Column 2 of Schedule C-1 between "Jurisdictional Adjustments to Base Period" (Column 2 of Schedule C-2) and "Jurisdictional Pro-Forma Adjustments to Forecasted Period" (Column 4 of Schedule C-2).

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[51] These amounts are shown at pages 1 – 6 of Schedule C-2.1, Column 5 for KU and LG&E Electric. This amount is shown at pages 1 – 5 of Schedule C-2.1, Column 5 for LG&E Gas.
[52] These mechanisms include DSM, ECR, FAC, and the OSS mechanisms for KU and LG&E Electric and the DSM, GLT, and GSC mechanisms for LG&E Gas.
[53] For KU and LG&E Electric, this value is shown in Column 4, line 14. For LG&E Gas, this value is shown in Column 4, line 13.

Schedule C-2, Column 2 represents adjustments to the base period amounts to reflect forecasted test period conditions. These adjustments are shown in detail on Schedule D-1, Column 2 and are described at Schedule D-1, Column 6.

Schedule C-2, Column 4 reflects the pro forma adjustments to forecasted test period operations. These adjustments are listed in detail in Schedule D-2.1. The amounts in Schedule C-2, Column 4 correspond to the amounts in the column labeled "Jurisdictional Pro Forma Adjustments to Forecast Period" on Schedule D-2.1.

Schedule C-2, Column 5 represents the pro forma forecasted test period amount. The amounts in Column 5 correspond to those in Schedule C-1, Column 3.

LG&E Gas

Gas Operations Schedule C-2 details LG&E Gas's adjusted jurisdictional operating income statement for the base period and the forecasted test period as used in Columns 1 and 3 of Schedule C-1, and breaks down "Forecasted Adjustments at Current Rates" per Column 2 of Gas Operations Schedule C-1 between "Jurisdictional Adjustments to Base Period" (Column 2 of Schedule C-2) and "Jurisdictional Pro Forma Adjustments to Forecasted Period" (Column 4 of Gas Operations Schedule C-2).

The amounts set forth in Gas Operations Schedule C-2, Column 1 reflect LG&E Gas's adjusted base period amounts as shown at pages 1 – 5 of Gas Operations Schedule C-2.1, Column 5. These amounts represent unadjusted base year totals adjusted to remove revenues and expenses associated with the DSM, GLT, and GSC mechanisms. The removal of these revenues and expenses are shown on Gas Operations Schedule D-2.

Gas Operations Schedule C-2, Column 2 represents adjustments to adjusted base period amounts to reflect forecasted test period conditions. These adjustments are shown in detail on Gas Operations Schedule D-1, Column 2 and described at Schedule D-1, Column 6.

Gas Operations Schedule C-2, Column 3 represents the forecasted test period levels prior to pro forma adjustments. These levels are obtained by applying the adjustments in Column 2 to the base period jurisdictional amounts in Column 1. The levels set forth in Column 3 corresponded to and are the same as the levels set forth at pages 6 – 10 of Gas Operations Schedule C-2.1, Column 5.

Gas Operations Schedule C-2, Column 4 reflects the pro forma adjustments to forecasted test period operations. These adjustments are listed in detail in Gas Operations Schedule D-2.1. The amounts in Schedule C-2, Column 4 correspond to the amounts found in the column "Jurisdictional Adjustments" on Schedule D-2.1.

Gas Operations Schedule C-2, Column 5 represents the pro forma forecasted test period amount. The amounts in Column 5 correspond to those in Gas Operations Schedule C-1, Column 3.

Schedule C-2.1

Schedule C-2.1 is a statement of jurisdictional operating revenues and expenses by account for the base period and for the forecasted test period. It details how each utility's jurisdictional net operating income was determined for the base period and forecasted test period.

Schedule C-2.2

Schedule C-2.2 is a comparison of each utility's operations on a monthly basis for the base period and for the forecasted test period. The information in this schedule is further classified by account. The information for the six months ending June 30, 2018 reflects actual results. The remaining months of the base period and all of the forecasted test period are forecasted.

APPENDIX D – RATE SCHEDULE

Schedule D

Each Schedule D is comprised of three schedules. Schedule D-1 shows operating revenue and expenses by account, for both the base period and the forecasted test period and the level of variance between the two. Certain jurisdictional pro forma adjustments are then applied to the forecasted test period to derive the pro forma forecasted test period used in Schedule C.

Schedule D-2 provides the adjustments for both the base period and the forecasted test period to operating revenues and expenses by FERC account necessary to remove the effects of each utility's other recovery mechanisms. In addition, an interest synchronization adjustment is made to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the rate mechanisms. The amounts shown in the "Jurisdictional Adjustments" column appear in column 4 of Schedule C-2.1 in the column "Jurisdictional Adjustments Sch D-2."

Schedule D-2.1 provides the pro forma adjustments to operating revenues and expenses by FERC account each utility is proposing in these proceedings for the forecasted test period. The amounts shown in the "Jurisdictional Pro Forma Adjustments to Forecast Period"[54] column appear in column 4 of Schedule D-1 in the column "Jurisdictional Pro Forma Adjustments to Forecasted Period."

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[54] For LG&E Gas, this column is titled "Jurisdictional Adjustments."

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS RATES	)))	**CASE NO. 2018-00294**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2018-00295**

DIRECT TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

LOUISVILLE GAS AND ELECTRIC COMPANY

AND KENTUCKY UTILITIES COMPANY

Filed: September 28, 2018

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. CAN YOU BRIEFLY DESCRIBE GANNETT FLEMING?

A. Yes. Gannett Fleming, Inc. is an international engineering consulting firm with expertise in numerous disciplines. Founded in 1915, Gannett Fleming Inc. has a long history of consulting services. The firm's headquarters is located in suburban Harrisburg, Pennsylvania. Regional offices are maintained in 23 states, one Canadian province, and an office in Qatar and the United Arab Emirates. With approximately 2,200 highly qualified individuals across a global network of 60 offices, we help shape infrastructure and improve communities in more than 65 countries. Gannett Fleming Valuation and Rate Consultants, LLC and its predecessor, the Valuation and Rate Division of Gannett Fleming, Inc., have provided service to utility companies since the late 1930s and, in the last five years, have prepared over 100 depreciation and valuation studies. Gannett Fleming staff has an unparalleled depth and breadth of experience in the field of depreciation. This expertise has been gained not only by conducting depreciation studies but also by actively participating within the depreciation field as educators and members of organizations that form depreciation standards.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since college graduation in June, 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am Senior Vice President.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member and past President of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. HAVE YOU HAD ANY ADDITIONAL EDUCATION RELATING TO UTILITY PLANT DEPRECIATION?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public

Utility Accounting" program conducted by the American Gas Association.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Yes. I have 32 years of depreciation experience which includes giving expert testimony in over 290 cases before 40 regulatory commissions, including this Commission. Please refer to Exhibit JJS-1 for my qualifications. In addition to the cases that I have submitted testimony, I have supervised over 600 other depreciation or valuation projects.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am sponsoring the depreciation studies that Gannett Fleming performed for Louisville Gas and Electric Company and Kentucky Utilities Company attached hereto as Exhibit JJS-LG&E-1 and Exhibit-JJS-KU-1.

II. DEPRECIATION STUDY

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDIES FILED BY LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY IN THIS PROCEEDING?

A. Yes. I prepared the depreciation studies submitted by Louisville Gas and Electric Company and Kentucky Utilities Company ("Companies") with their filings in this proceeding. These studies are attached as Exhibits JJS-LG&E-1 and JJS-KU-1. My reports are entitled: "2017 Depreciation Study - Calculated Annual Depreciation Accruals Related to Steam Generation Plant as of December 31, 2017." These reports set forth the results of my depreciation studies for each Company.

Q. IN PREPARING THE DEPRECIATION STUDIES, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. ARE THE METHODS AND PROCEDURES OF THESE DEPRECIATION STUDIES CONSISTENT WITH PAST PRACTICES?

A. The methods and procedures of these studies are the same as those utilized in past studies of each Company as well as others before this Commission. The depreciation rates recommended in my studies are determined based on the average service life procedure and the remaining life method.

Q. ARE THE UNDERLYING LIFE AND NET SALVAGE PARAMETERS AND RESULTING DEPRECIATION ISSUES IN THIS STUDY CONSISTENT WITH INDUSTRY TRENDS?

A. Yes. The life and net salvage parameters for LG&E and KU have changed consistently with others in the industry as well as the major changes to steam production asset mix.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORTS.

A. Each Depreciation Study is presented in nine parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

Table 1 on pages VI-4 and VI-5 of Exhibit JJS-LG&E-1 and on pages VI-4 and VI-5 of Exhibit JJS-KU-1 present the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2017, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2017.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. WILL YOU PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP?

A. The service life and net salvage studies consisted of compiling historical data from records related to Louisville Gas and Electric Company's and Kentucky Utilities Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans related to plant operations; and interpreting the data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Companies' accounting entries that record plant transactions during the period 1954 through 2017 for LG&E and during the period 1926 through 2017 for KU. The transactions included additions, retirements, transfers, sales and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Companies' during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE BOTH COMPANIES' SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in each study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. A survivor curve is a graphical depiction of the amount of property existing at each age throughout the life of an asset class. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa curve system to which the property group belongs, and the relative height of the mode. For example, the Iowa 70-R1.5 indicates an average service life of seventy years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT FACILITIES STRUCTURES SUCH AS PRODUCTION PLANTS?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows, roofs, etc., that occurs during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. HAS GANNETT FLEMING USED THIS APPROACH IN OTHER PROCEEDINGS?

A. Yes, we have used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada, including Kentucky. This technique is currently being utilized by Louisville Gas and Electric Company and Kentucky Utilities Company in the same manner recommended in this case.

Q. WHAT ARE THE BASES FOR THE PROBABLE RETIREMENT YEARS THAT YOU HAVE ESTIMATED FOR EACH FACILITY?

A. The bases for the probable retirement years are life spans for each facility that are based on informed judgment, and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirements of these facilities are not yet subject to specific management plans. Such plans would be premature. At the appropriate time, studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated into the estimation of the facility's life span.

Q. HAVE YOU PHYSICALLY OBSERVED LG&E'S AND KU'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDIES?

A. Yes. I have made field reviews of LG&E and KU's property as part of past studies during April and May 2007, October 2011 and October 2015 to observe representative portions of plant. Field reviews are commonly taken every 4 to 5 years in order to identify change in asset condition. Field reviews are conducted to become familiar with a company's operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1972 through 2017 for LG&E and 1988 through 2017 for KU and considered estimates for other electric companies.

Q. HAVE YOU INCLUDED A DISMANTLEMENT COMPONENT INTO THE OVERALL RECOVERY OF GENERATING FACILITIES?

A. Yes. A dismantlement component has been included to the net salvage percentage for all steam production facilities.

Q. CAN YOU EXPLAIN WHY AND HOW THE DISMANTLEMENT COMPONENT IS INCLUDED IN THE DEPRECIATION STUDY?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of some LG&E and KU facilities, it was determined that the dismantlement or decommissioning costs for steam production facilities are best calculated at $40/KW of the assets subject to final retirement. The cost estimate of dismantlement of the Cane Run facility was a primary resource for the $40/KW component as Cane Run is most similar to the remaining facilities to be dismantled. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculation for each location is set forth on page VIII-2 Exhibit JJS-LG&E-1 and page VIII-2 of Exhibit JJS-KU-1.

Q. IS THIS METHODOLOGY A CHANGE FROM CURRENT PRACTICES?

A. No. The current practice for LG&E and KU includes a low level of terminal net salvage combined with the interim net salvage percentage. In this study, the methodology continues to advance to a more precise practice and is utilized by most utilities. The weighting of the interim and final net salvage by location establishes a more precise recovery pattern for each location.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED THE COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using the remaining lives weighted consistent with the average service life procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDIES.

A. I will use KU Plant Account 312, Boiler Plant Equipment, as an example because it is the largest depreciable account and represents approximately 79% of depreciable steam production plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1926 through 2017 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1926-2017 and 1978-2017 experience bands are presented on pages VII-8 through VII-11 of the report. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-__ shows $2,670,287 retired at age 1.5 with $3,983,390,994 exposed to retirement. Consequently, the retirement ratio is 0.0007; and the surviving ratio is 0.9993. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, as shown on the 70-R1.5 on page VII-7.

The interim net salvage analyses for Account 312, Boiler Plant Equipment, is presented on pages VIII-5 and VIII-6 of the Depreciation Study. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1988 through 2017. This 30-year period experienced $43,002,073 ($3,929,933-$46,932,006) in negative net salvage for $155,030,596 plant retired. The result is negative net salvage of 28 percent ($43,002,073/$155,030,596). Based on the overall negative 28 percent net salvage and the most recent five years of negative 31 percent, it was determined that negative 30 percent is the most appropriate interim estimate. The percentage is combined with the terminal net salvage component by location to create a weighted net salvage percent by unit.

My calculation of the annual depreciation related to the original cost at December 31, 2017, of utility plant is presented on pages IX-15 through IX-25. The calculation is based on the 70-R1.5 survivor curve, weighted negative net salvage by unit of 6 to 13 percent, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-4.

Q. ARE REQUIREMENTS AND DEPRECIATION RATES FOR STEAM ASSETS CHANGING MORE FREQUENTLY THAN OTHER ELECTRIC ASSETS?

A. Yes. Many utilities assets have long physical lives, however, service lives are driven by more than physical characteristics. In the case of steam assets, and particularly coal assets, review of depreciation rates need to be updated more frequently due to regulations.

Q. WERE THERE SPECIFIC GENERATING UNITS WHICH HAVE CONSIDERABLE CHANGE IN LIFE EXPECTATION?

A. Yes. The E.W. Brown Units 1 and 2 have much shorter remaining lives that are driven by more than physical characteristics. E. W. Brown Units 1 and 2 are to be retired by February 2019.

Q. HAS THE SHORTER REMAINING LIFE FOR BROWN UNITS 1 AND 2 BEEN REFLECTED IN HIGHER DEPRECIATION RATES?

A. No. The accumulated depreciation of the Brown Units 1 and 2 have been adjusted to reflect the more appropriate theoretical reserve. The amount of the adjustment is offset by Brown Unit 3, which has a longer remaining life.

III. CONCLUSION

Q. IN YOUR OPINION, ARE THE DEPRECIATION RATES SET FORTH IN EXHIBIT JJS-LG&E-1 AND EXHIBIT JJS-KU-1 THE RECOMMENDED RATES FOR THE KENTUCKY PUBLIC SERVICE COMMISSION TO ADOPT IN THIS PROCEEDING FOR LG&E AND KU?

A. Yes, these rates appropriately reflect the rates at which the value of LG&E's and KU's steam generation assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric rates in this matter and for the Companies' to use for booking depreciation expense going forward.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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 for Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos

John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 4th day of September 2018.

(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

Exhibit JJS-1

Qualifications

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. Please outline your experience in the field of depreciation.

A. In June, 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June, 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July, 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December, 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas

Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company and Northern Illinois Gas Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal

Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Co.	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Co.	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Co.	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Co.	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Co.	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Co.	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Co.	Depreciation
47.	2006	NC Util Cm.		Pub. Service Co. of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	ISO82, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Co.	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co.-Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Co.	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Co.	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Co.	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Co.	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Co.	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Co.	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Co.	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Co.	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Co.	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Co. - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	Lancaster, City of – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
130.	2011	Il CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Co.	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation
133.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Hanover, Borough of – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Co.	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Co.– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Co.	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Co.	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Co. – PEPCO	Depreciation
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Co.	Depreciation
167.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Co.	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Hanover, Borough of – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	Suez Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Co. – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Co. – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC		Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UT&C	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Oklahoma, Public Service Company of	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER17-___	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No.	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	Docket Nos. ER-18-___-000	Duke Energy Carolinas, LLC	Depreciation

Exhibit JJS-KU-1

KU Depreciation Study

KENTUCKY UTILITIES COMPANY

LOUISVILLE, KENTUCKY

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO STEAM GENERATION
PLANT AS OF DECEMBER 31, 2017

Prepared by:

Gannett Fleming

Excellence Delivered **As Promised**

KENTUCKY UTILITIES COMPANY

Louisville, Kentucky

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO STEAM GENERATION PLANT AS OF DECEMBER 31, 2017

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Harrisburg, Pennsylvania

Gannett Fleming

Excellence Delivered **As Promised**

September 4, 2018

Kentucky Utilities Company
220 West Main Street, Suite 1400
Louisville, KY 40202-1345

Attention Christopher M. Garrett
Controller

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the steam generation plant of Kentucky Utilities Company as of December 31, 2017. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J. Spanos

JOHN J. SPANOS
Sr. Vice President

JJS:mle

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KENTUCKY UTILITIES COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Kentucky Utilities Company's ("KU" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the steam generation plant as of December 31, 2017. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets.

KU's accounting policy has not changed since the last depreciation study was prepared. However, there have been significant changes in past and future retirement plans of assets. These changes have caused the proposed remaining lives for many accounts to fluctuate from those proposed in the previous depreciation study as of December 31, 2015.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to steam generation plant in service as of December 31, 2017 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $192.1 million when applied to depreciable plant balances as of December 31, 2017.

PART I. INTRODUCTION

KENTUCKY UTILITIES COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Kentucky Utilities Company ("Company"), as applied to specific steam generation plant in service as of December 31, 2017. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to current electric plant in service.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2017, the net salvage analyses of historical plant retirement data recorded through 2017; a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average servicelife analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued

Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For all accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts. For steam production plants, the life span technique was used. In this technique, the date of final retirement was estimated for each unit, and the estimated survivor curves applied to each vintage were truncated at ages coinciding with the date of final retirement.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The estimates of net salvage by account incorporated a review of experienced costs of removal and salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or 0) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of

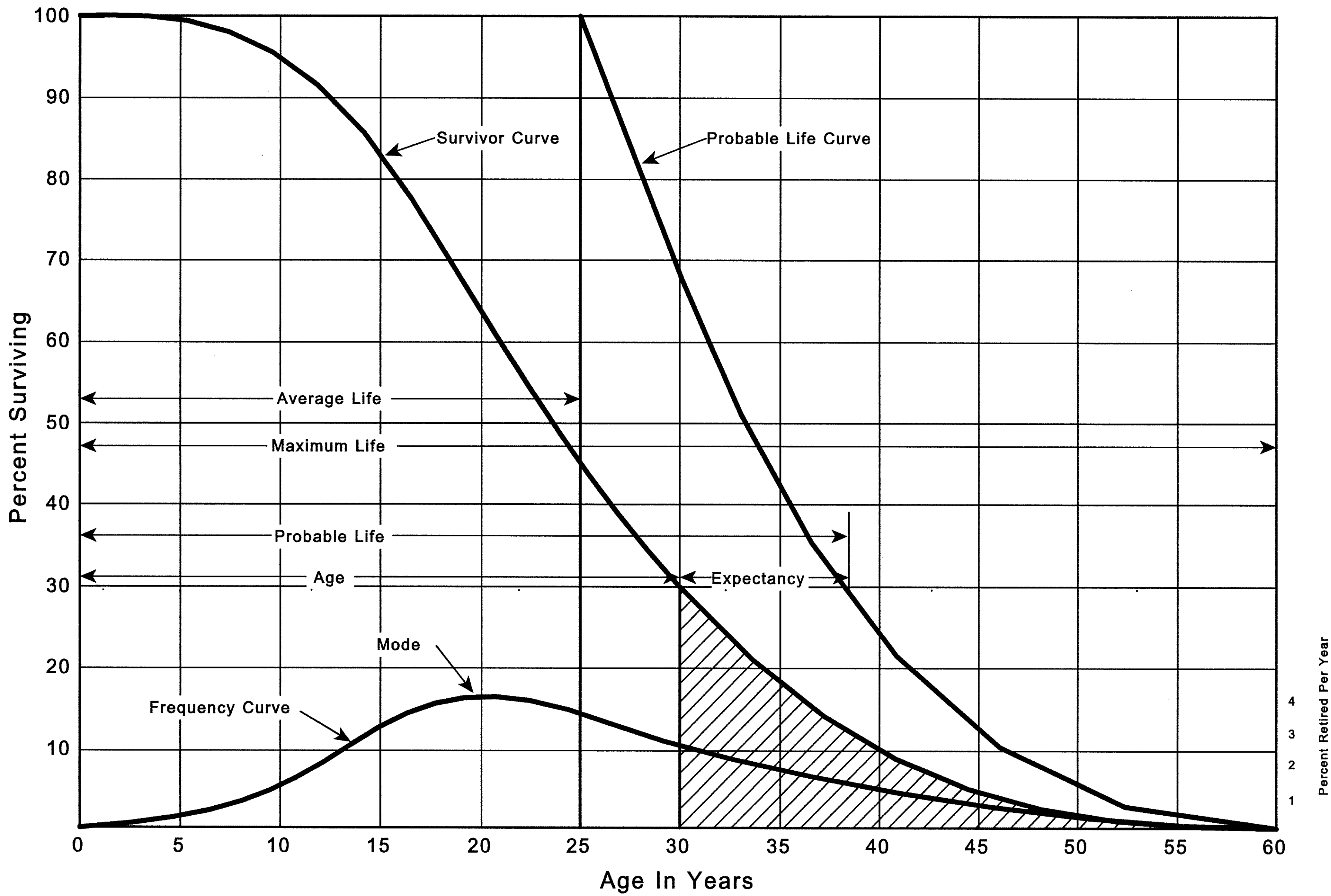


Figure 1. A Typical Survivor Curve and Derived Curves

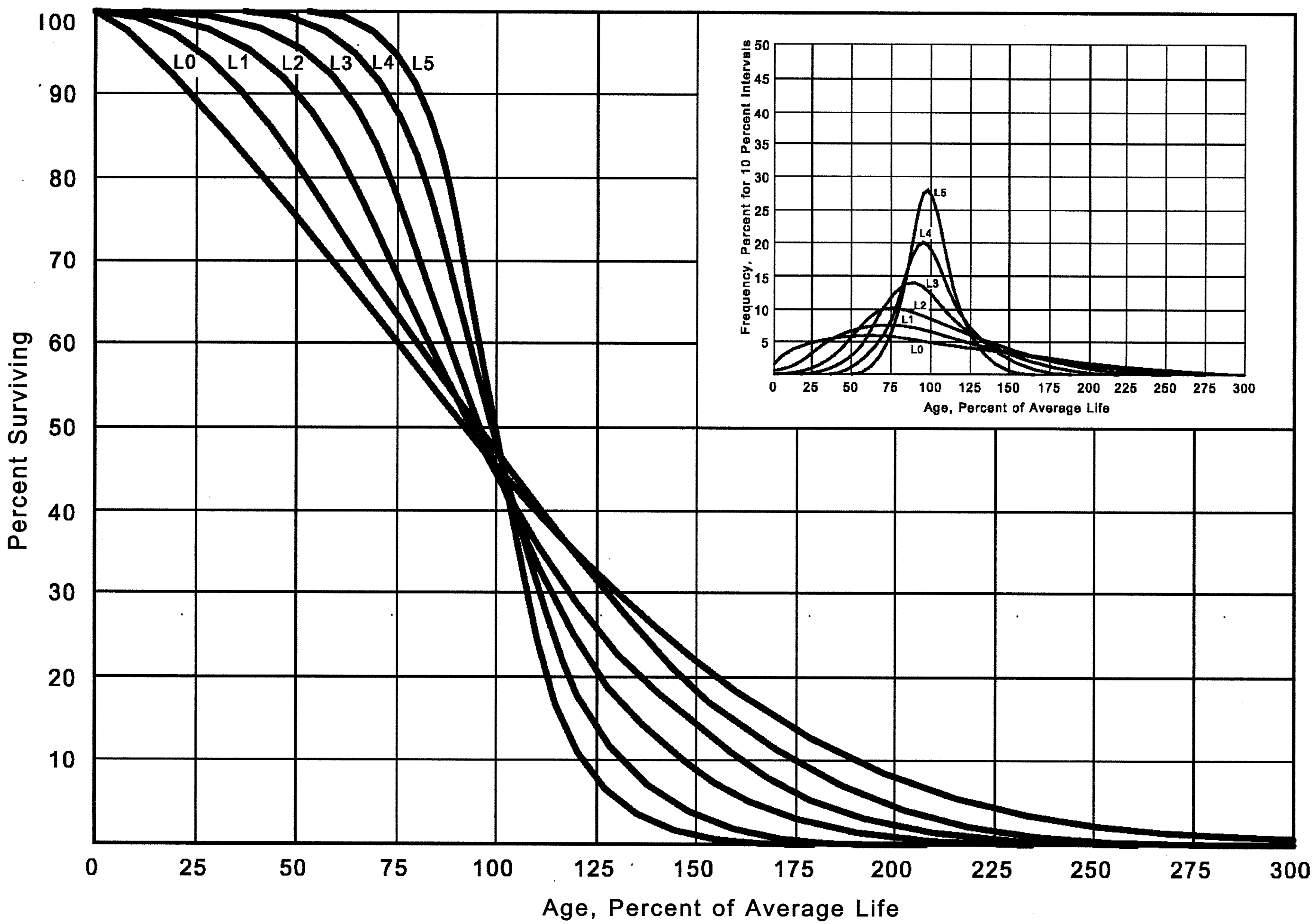


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

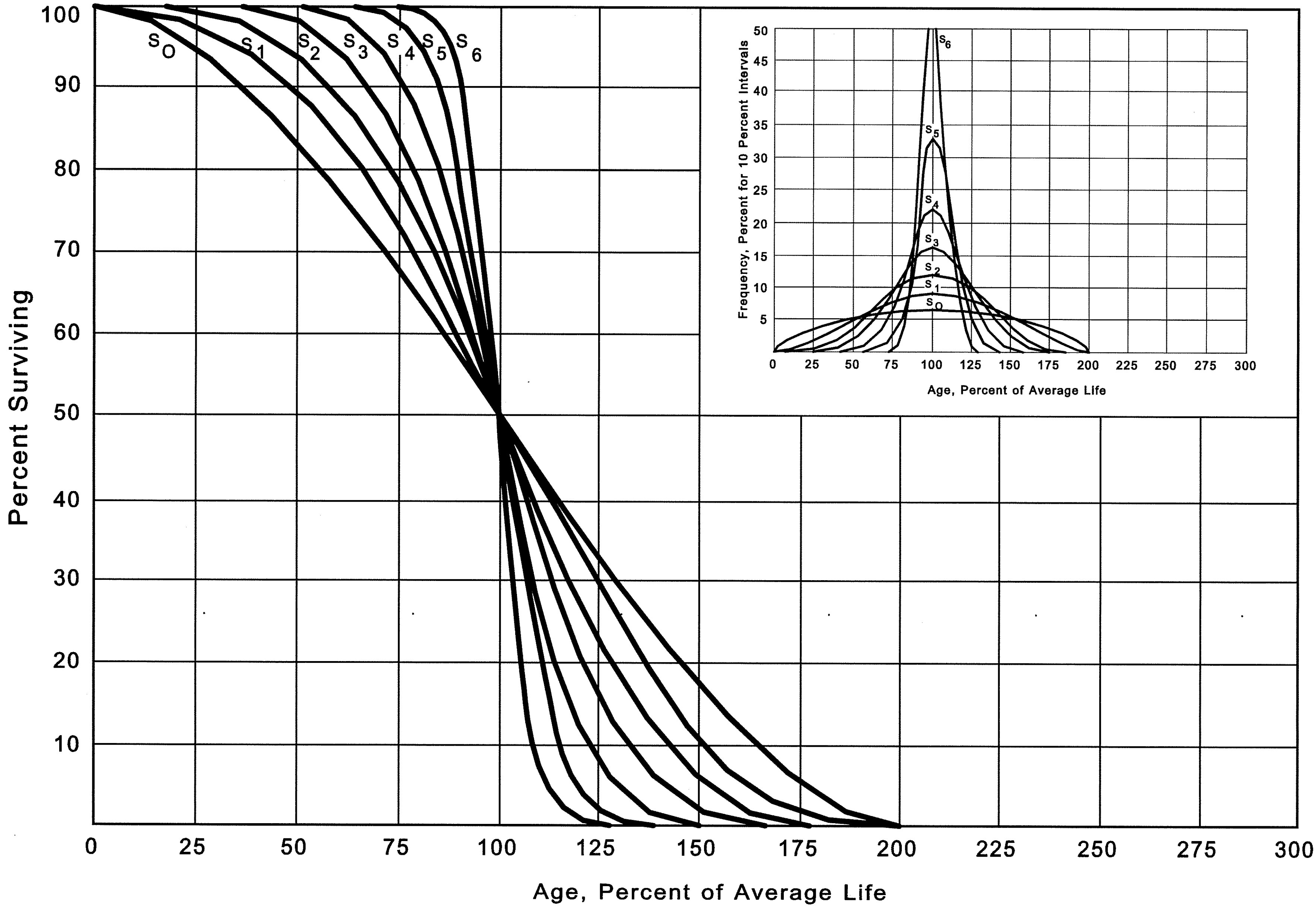


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

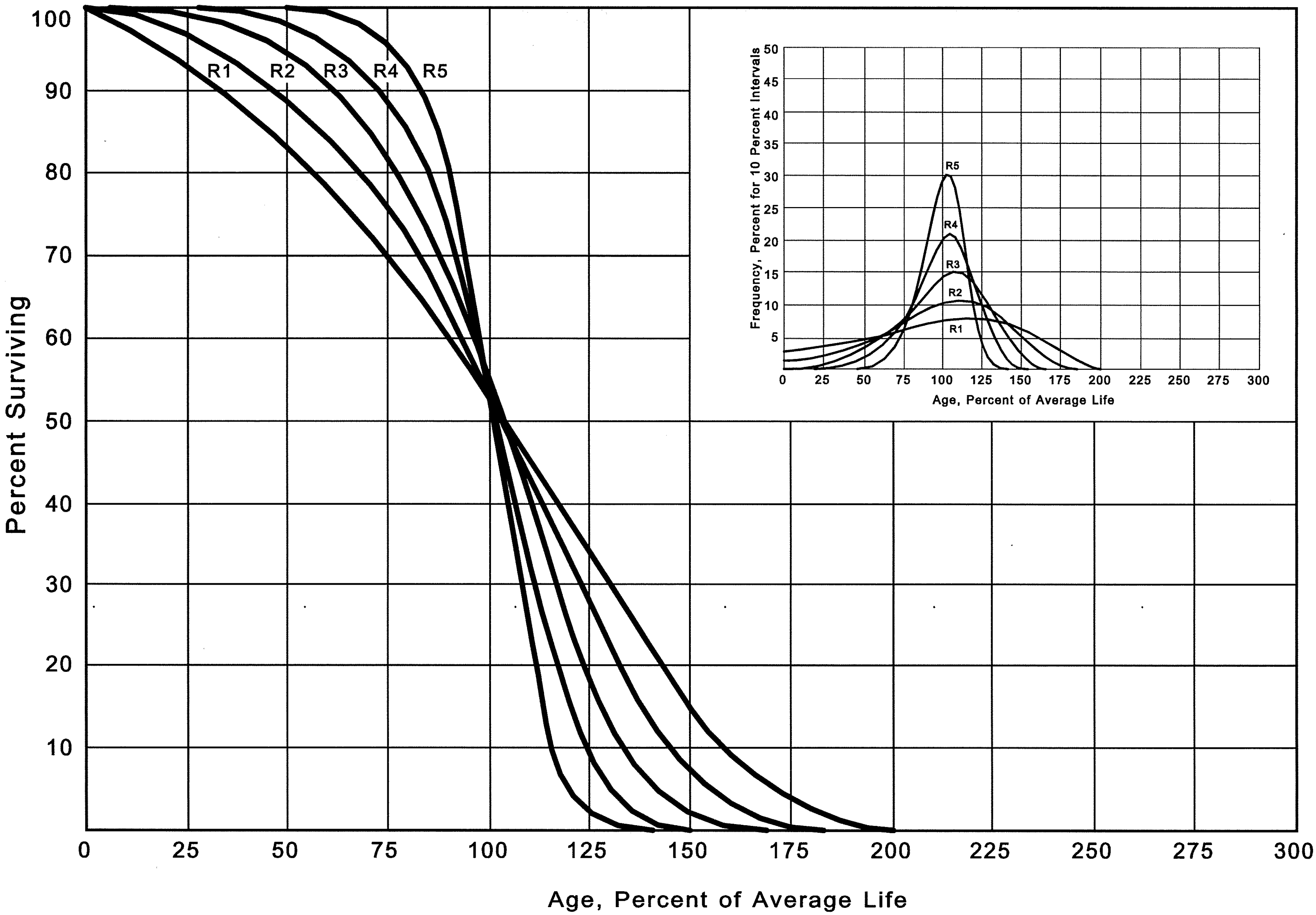


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

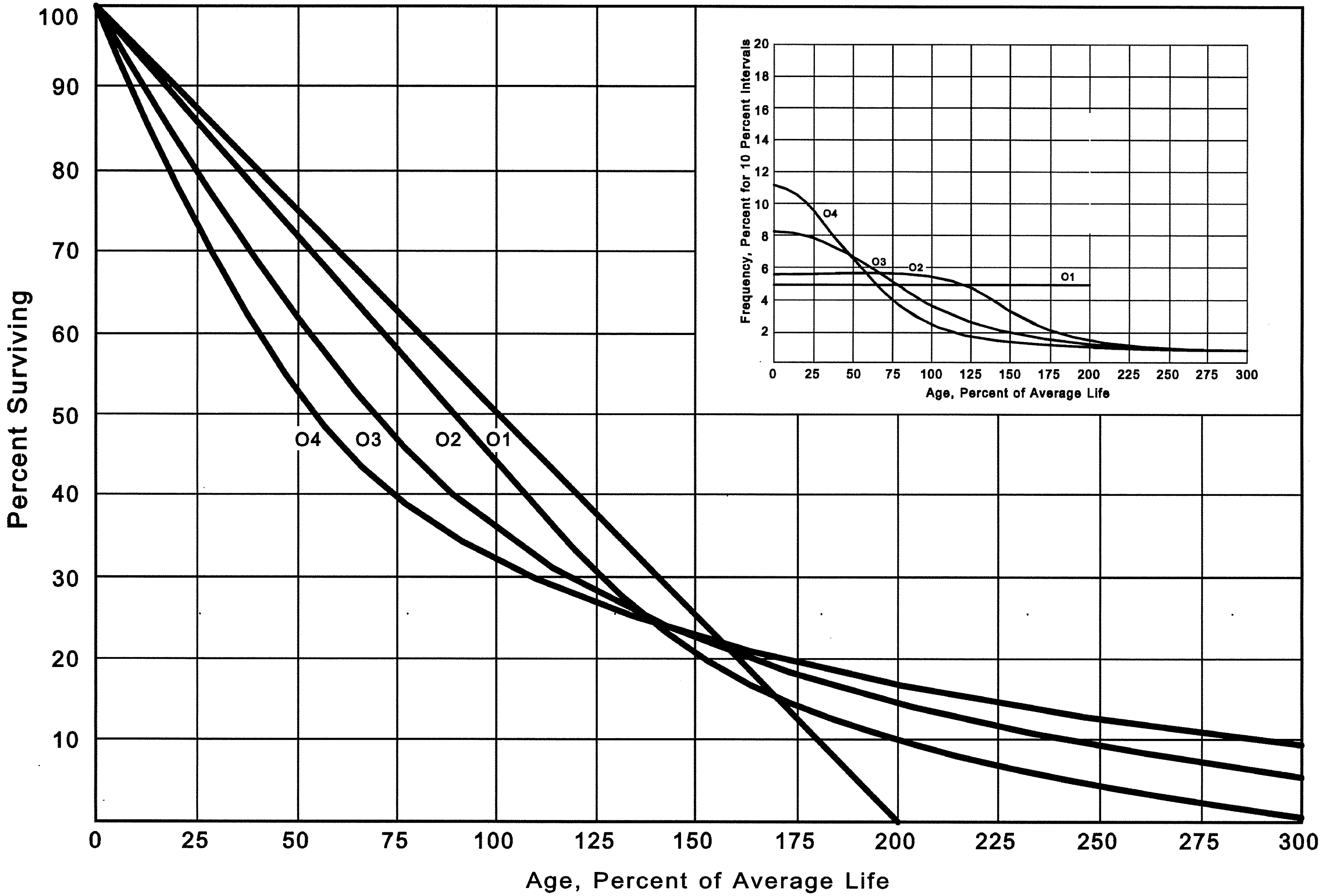


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

the Experiment Station's Bulletin 125. These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements"[2], "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows.

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Roble, Statistical Analyses of Industrial Property Retirements. Iowa State College Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Roble Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½ - 5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2017 retirements of the 2012 installations. Thus, the total amount of 143 for age interval 4½ - 5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 | Placement Band 2003-2017

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total During Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	6	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2008 through 2017 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or additions are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0 = amount of addition	= $750,000
Exposures at age ½ = $750,000 - $8,000	= $742,000
Exposures at age 1½ = $742,000 - $18,000	= $724,000
Exposures at age 2½ = $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½ = $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total at Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	926	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2008-2017, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½ – 5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ areas as follows:

Percent surviving at age 4½	=	88.15
Exposures at age 4½	=	3,789,000
Retirements from age 4½ to 5½	=	143,000
Retirement Ratio	=	143,000 ÷ 3,789,000 = 0.0377
Survivor Ratio	=	1.000 - 0.0377 = 0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623) = 84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017 Placement Band 2003-2017

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

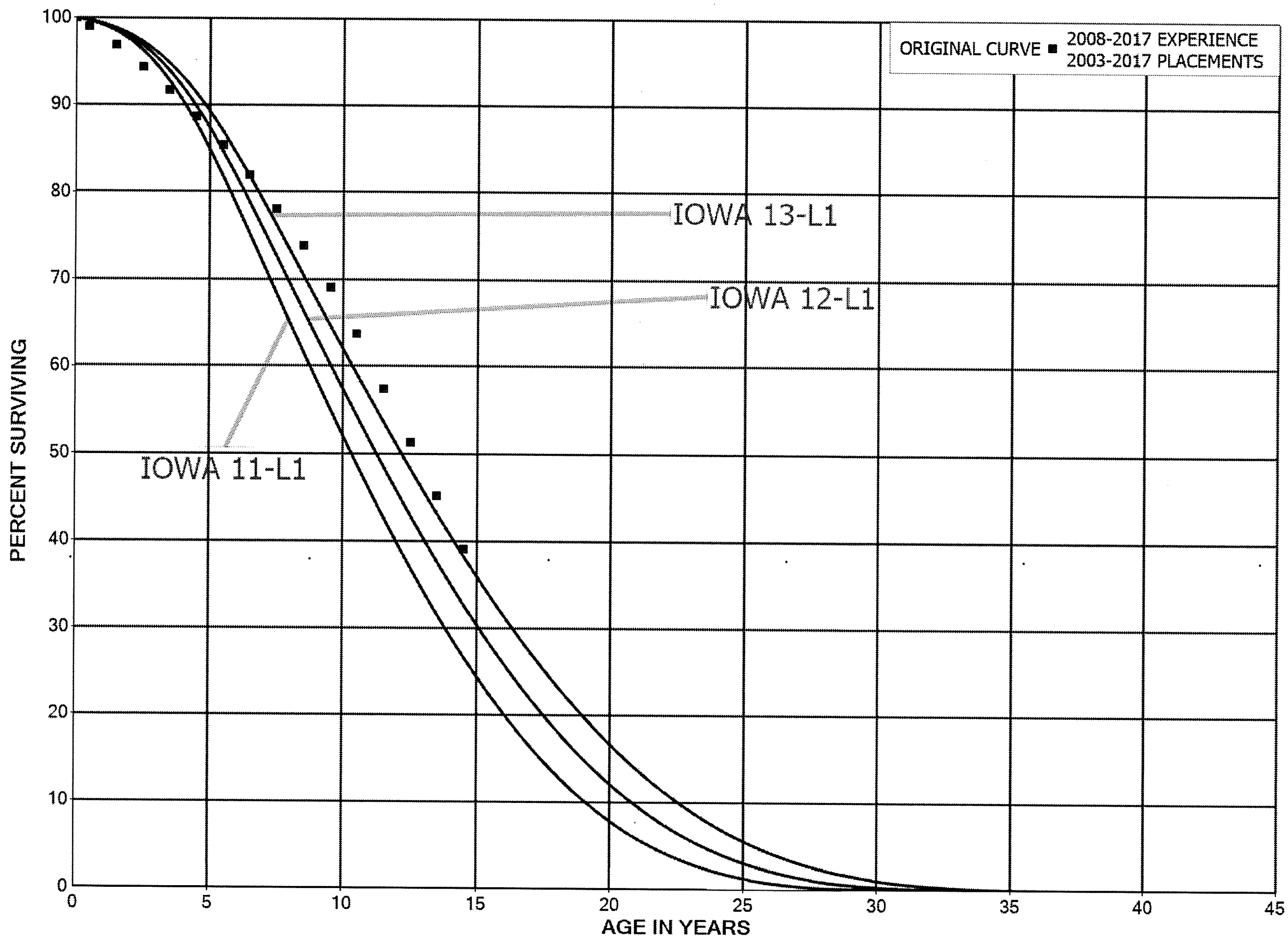


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

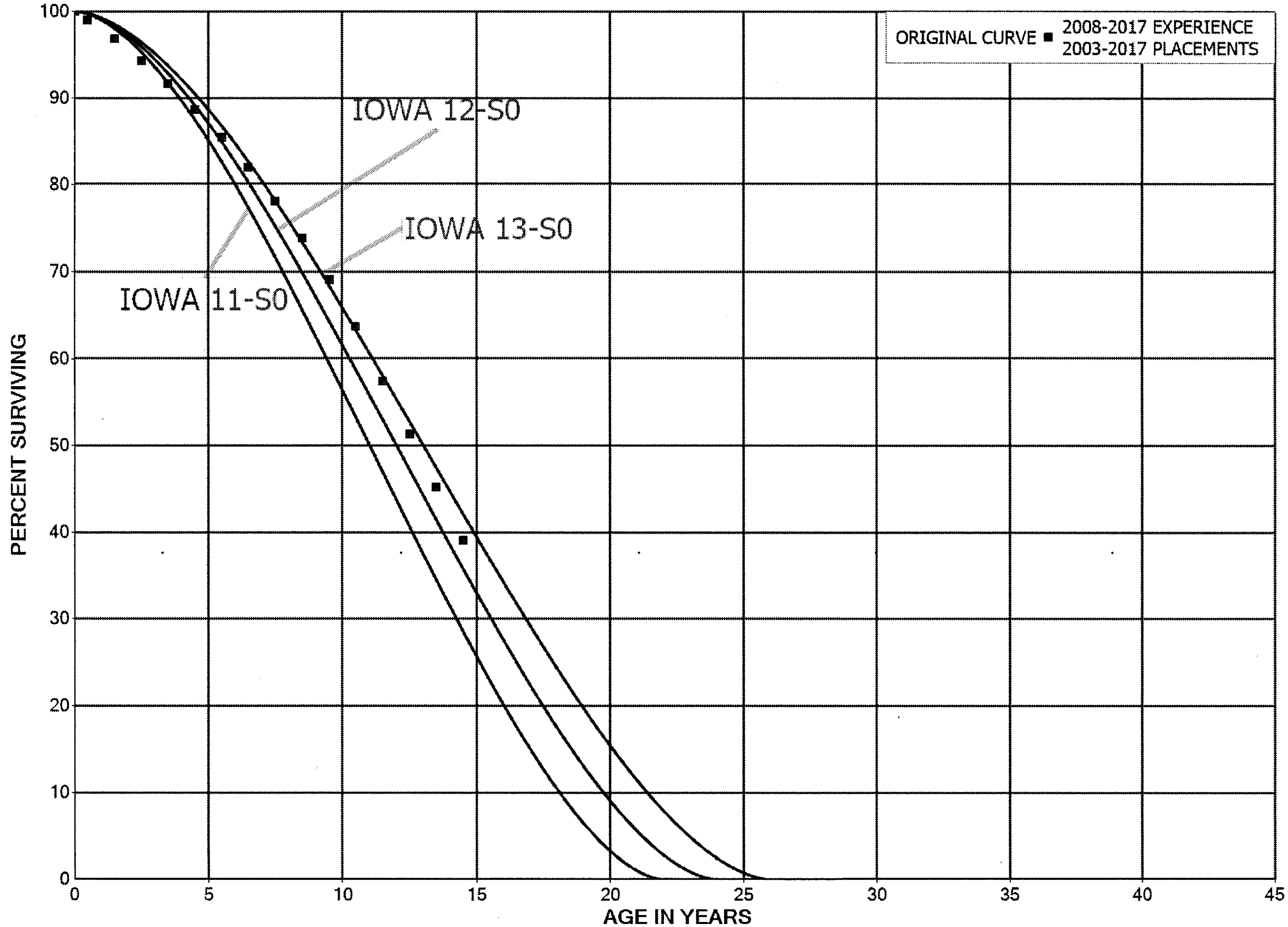


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

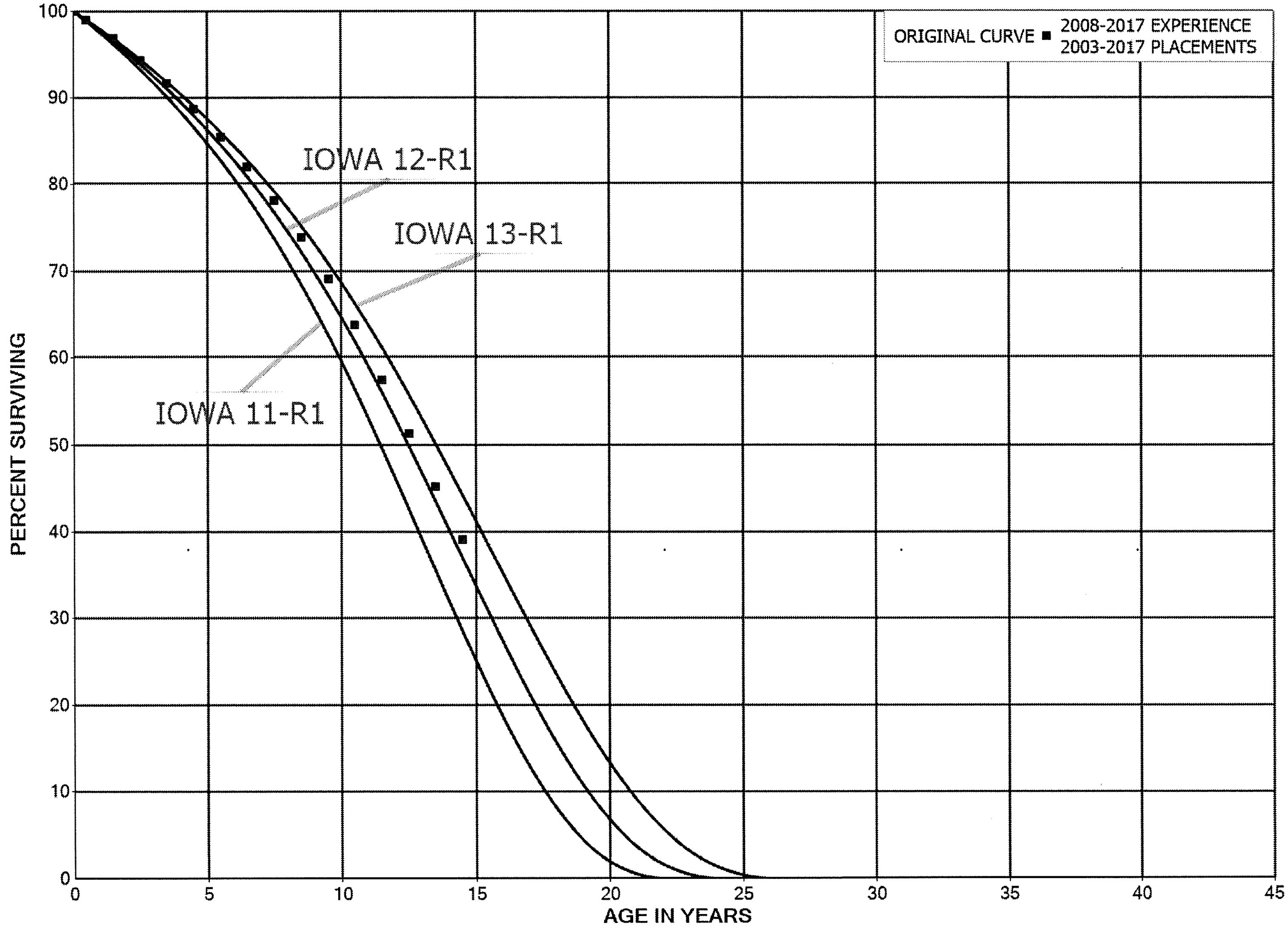
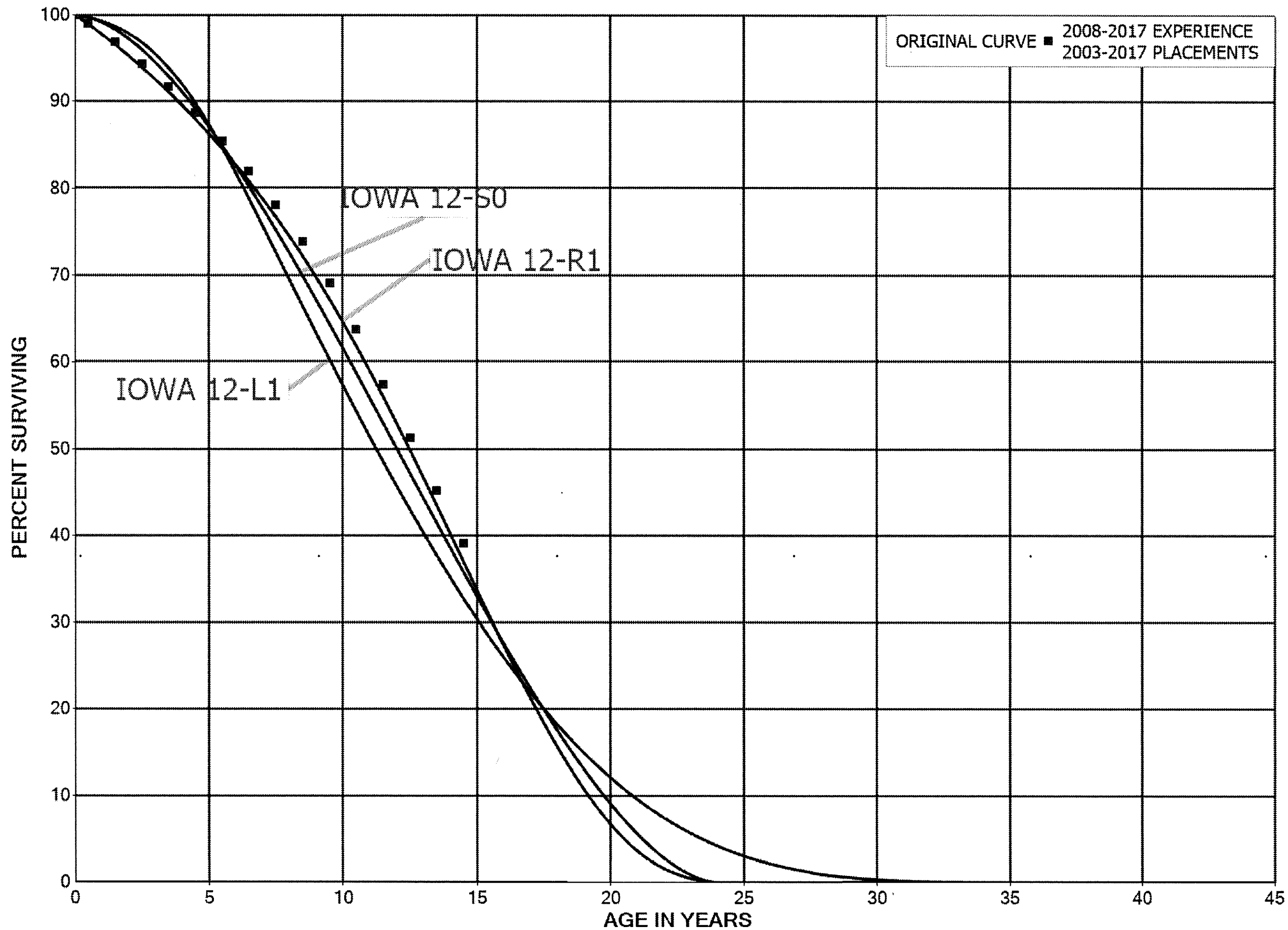


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during recent field trips.

<u>October 20, 2015</u>
E.W. Brown Generating Facility
Ghent Generating Facility

<u>October 10-11, 2011</u>
E.W. Brown Generating Facility
Tyrone Generating Facility
Ghent Generating Facility
Trimble County Generating Facility

<u>April 23-25, 2007</u>
Trimble County Generating Facility
Ghent Generating Facility
E.W. Brown Generating Facility

SERVICE LIFE ANALYSIS

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data, current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies.

For most plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. Generally, the information external to the statistics led to minimal or no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

STEAM PRODUCTION PLANT

311	Structures and Improvements
312	Boiler Plant Equipment
314	Turbogenerator Units
316	Miscellaneous Power Plant Equipment

Account 314, Turbogenerator Units, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Account 314 represents approximately 7 percent of the total depreciable plant. Aged plant accounting data have been compiled for the years 1926 through 2017. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate for Account 314, Turbogenerator Units, is based on the statistical indications for the periods 1926 through 2017 and 1978 through 2017. The Iowa 60-R2 is an excellent fit of the original survivor curve. The 60-year interim service life is within the typical service life range of 50 to 70 years for turbogenerator units. The 60-year life reflects the Company's practices of continual component upgrades and turbine overhauls for all vintages. The previous estimate was the Iowa 60-R2.

Life Span Estimates

Inasmuch as production plant consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for steam production plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1926 through 2017.

The depreciable life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units and observed features and conditions at the time of the field visit. These life spans represent the expected depreciable life of each facility under their current configuration. The life span estimate for most steam, base-load units is 54 to 64 years, which is within the typical range of life spans for such units.

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Tyrone Unit 3	1947,1953	2015	68,62
Tyrone Units 1 & 2	1947,1948	2015	68,67
Green River Unit 3	1954	2015	61
Green River Unit 4	1959	2015	56
Green River Units 1 & 2	1950	2015	65
Brown Unit 1	1956	2019	63
Brown Unit 2	1963	2019	56

Brown Unit 3	1971	2035	64
Pineville Unit 3	1951	2015	64
Ghent Unit 1	1974	2034	60
Ghent Unit 2	1977	2034	57
Ghent Unit 3	1981	2037	56
Ghent Unit 4	1984	2038	54
Trimble County Unit 2	1990,2011	2066	76,55

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled through 2017. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and salvage data are presented in the section titled "Net Salvage Statistics" for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period, 1985 through 2017 by plant account were analyzed. The analyses contributed significantly toward the net salvage estimates for most plant accounts, representing 93 percent of the depreciable plant, as follows:

STEAM PRODUCTION

311	Structures and Improvements
312	Boiler Plant Equipment
314	Turbogenerator Units
316	Miscellaneous Power Plant Equipment

The overall net salvage estimates for the Company's production facilities, for which the life span method is used, is based on estimates of both terminal net salvage and interim net salvage. Terminal net salvage is the net salvage experienced at the end of a production plant's life span. Interim net salvage is the net salvage experienced for interim retirements that occur prior to the final retirement of the plant. The terminal net salvage estimates in the study were based on decommissioning costs assigned to comparable facilities. The interim net salvage estimates were based in part on an analysis of historical interim retirement and net salvage data. Based on informed judgment that incorporated these interim net salvage analyses for each plant account, an interim net salvage estimate between 2 and 30 percent was used for each steam plant account.

The interim survivor curve estimates for each account and production facility were used to calculate the percentage of plant expected to be retired as interim retirements and terminal retirements. These are shown on Table 2 in the Net Salvage Statistics section on page VIII-2. These percentages were used to determine the weighted net salvage estimate for each account and production facility based on the interim and terminal net salvage estimates. These calculations, as well as the estimated terminal net salvage amounts and interim net salvage percents, are shown on Table 2 of the Net Salvage Statistics section on page VIII-2.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4+6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2017, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2017, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$\mathit{Ratio} = 1 - \frac{\mathit{Average\ Remaining\ Service\ Life}}{\mathit{Average\ Service\ Life}}$$

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2017. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2017, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of salvage data are presented in the section titled, "Net Salvage Statistics". The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant as of December 31, 2017, is presented on pages VI-4 and VI-5 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount.

KENTUCKY UTILITIES COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

	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)
	DEPRECIABLE PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	TRIMBLE COUNTY UNIT 2	105-R2.5	*	(13)	96,307,268.16	27,875,957	80,951,256	1,740,732	1.81	46.5
	TRIMBLE COUNTY UNIT 2 SCRUBBER	105-R2.5	*	(13)	5,556,451.46	3,229,484	3,049,306	67,265	1.21	45.3
	SYSTEM LABORATORY	105-R2.5	*	0	1,117,119.13	736,160	380,959	17,187	1.54	22.2
	BROWN UNIT 1	105-R2.5	*	(6)	4,677,142.79	4,955,316	2,455	2,099	0.04	1.2
	BROWN UNIT 2	105-R2.5	*	(6)	2,309,727.39	2,431,335	16,976	14,510	0.63	1.2
	BROWN UNIT 3	105-R2.5	*	(6)	28,754,404.33	14,706,856	15,772,813	910,368	3.17	17.3
	BROWN UNIT 1, 2 AND 3 SCRUBBER	105-R2.5	*	(6)	45,382,543.88	12,264,813	35,840,684	2,062,175	4.54	17.4
	GHENT UNIT 1 SCRUBBER	105-R2.5	*	(8)	8,397,192.12	7,509,513	1,559,454	95,610	1.14	16.3
	GHENT UNIT 1	105-R2.5	*	(8)	21,345,248.67	17,200,351	5,852,518	358,281	1.68	16.3
	GHENT UNIT 2	105-R2.5	*	(8)	16,653,049.60	14,451,749	3,533,545	218,196	1.31	16.2
	GHENT UNIT 3	105-R2.5	*	(8)	51,457,056.74	34,353,891	21,219,730	1,106,327	2.15	19.2
	GHENT UNIT 4	105-R2.5	*	(8)	43,271,160.71	16,660,841	30,072,013	1,486,395	3.44	20.2
	GHENT UNIT 2 SCRUBBER	105-R2.5	*	(8)	15,816,339.70	14,084,948	2,996,699	183,959	1.16	16.3
	GHENT UNIT 4 SCRUBBER	105-R2.5	*	(8)	36,901.04	0	39,853	1,958	5.31	20.4
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				341,081,605.72	170,461,214	201,288,261	8,265,062	2.42	24.4
311.20	STRUCTURES AND IMPROVEMENTS - RETIRED PLANT									
	TYRONE UNIT 3	105-R2.5	*	(10)	1,821,179.50	2,003,297	0	0	-	-
	TYRONE UNITS 1 AND 2	105-R2.5	*	(10)	630,860.03	693,946	0	0	-	-
	GREEN RIVER UNIT 3	105-R2.5	*	(10)	2,756,302.50	3,031,933	0	0	-	-
	GREEN RIVER UNIT 4	105-R2.5	*	(10)	5,631,448.40	6,194,593	0	0	-	-
	GREEN RIVER UNITS 1 AND 2	105-R2.5	*	(10)	1,756,471.53	1,932,119	0	0	-	-
	PINEVILLE UNIT 3	105-R2.5	*	(10)	182,442.49	200,687	0	0	-	-
	TOTAL ACCOUNT 311.2 - STRUCTURES AND IMPROVEMENTS - RETIRED PLANT				12,778,704.45	14,056,575	0	0	-	-
312.00	BOILER PLANT EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	70-R1.5	*	(13)	554,266,452.52	110,556,316	515,764,775	12,038,282	2.17	42.8
	TRIMBLE COUNTY UNIT 2 SCRUBBER	70-R1.5	*	(13)	72,953,390.63	21,555,951	60,881,380	1,429,927	1.96	42.6
	BROWN UNIT 1	70-R1.5	*	(6)	38,556,575.43	39,433,716	1,436,254	1,238,148	3.21	1.2
	BROWN UNIT 2	70-R1.5	*	(6)	42,204,805.56	43,229,373	1,507,721	1,299,759	3.08	1.2
	BROWN UNIT 3	70-R1.5	*	(6)	442,651,264.76	80,166,586	389,043,755	22,988,128	5.19	16.9
	BROWN UNIT 1, 2 AND 3 SCRUBBER	70-R1.5	*	(6)	335,178,567.22	75,103,808	280,185,473	16,498,201	4.92	17.0
	GHENT UNIT 1 SCRUBBER	70-R1.5	*	(8)	139,576,135.58	57,639,685	93,102,541	5,810,674	4.16	16.0
	GHENT UNIT 1	70-R1.5	*	(8)	355,931,120.22	110,114,714	274,290,896	17,179,573	4.83	16.0
	GHENT UNIT 2	70-R1.5	*	(8)	277,188,781.51	74,139,461	225,224,423	14,124,142	5.10	15.9
	GHENT UNIT 3	70-R1.5	*	(8)	433,488,085.02	181,912,764	286,254,368	15,353,337	3.54	18.6
	GHENT UNIT 4	70-R1.5	*	(8)	751,196,369.80	168,106,676	643,185,403	32,693,892	4.35	19.7
	GHENT UNIT 2 SCRUBBER	70-R1.5	*	(8)	70,125,568.12	62,367,365	13,368,249	836,182	1.19	16.0
	GHENT UNIT 3 SCRUBBER	70-R1.5	*	(8)	119,327,931.24	39,524,131	89,350,035	4,765,380	3.99	18.7
	GHENT UNIT 4 SCRUBBER	70-R1.5	*	(8)	254,161,647.89	95,407,708	179,086,872	9,062,789	3.57	19.8
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				3,886,806,695.50	1,159,258,254	3,052,682,145	155,318,414	4.00	19.7
312.10	BOILER PLANT EQUIPMENT - ASH PONDS									
	TRIMBLE COUNTY UNIT 2	100-S4	*	0	9,104,044.87	5,018,153	4,085,892	680,982	7.48	6.0
	BROWN UNIT 1	100-S4	*	0	9,299,115.00	9,298,845	270	90	0.00	3.0
	BROWN UNIT 2	100-S4	*	0	3,909,061.67	2,991,413	917,649	305,883	7.82	3.0
	BROWN UNIT 3	100-S4	*	0	19,802,080.26	5,142,558	14,659,522	4,886,507	24.68	3.0
	GHENT UNIT 1 SCRUBBER	100-S4	*	0	39,480.55	39,209	272	91	0.23	3.0
	GHENT UNIT 1	100-S4	*	0	2,100,620.94	2,073,761	26,860	5,372	0.26	5.0
	GHENT UNIT 4	100-S4	*	0	32,692,663.87	14,310,027	18,382,637	4,595,659	14.06	4.0
	GHENT UNIT 2 SCRUBBER	100-S4	*	0	1,901,133.18	1,901,133	0	0	-	-
	TYRONE UNIT 3	100-S4	*	0	575,455.72	575,456	0	0	-	-
	GREEN RIVER UNIT 3	100-S4	*	0	1,831,840.98	1,831,841	0	0	-	-
	PINEVILLE UNIT 3	100-S4	*	0	91,265.89	91,266	0	0	-	-
	TOTAL ACCOUNT 312.1 - BOILER PLANT EQUIPMENT - ASH PONDS				81,346,762.93	43,273,662	38,073,102	10,474,584	12.88	3.6

KENTUCKY UTILITIES COMPANY

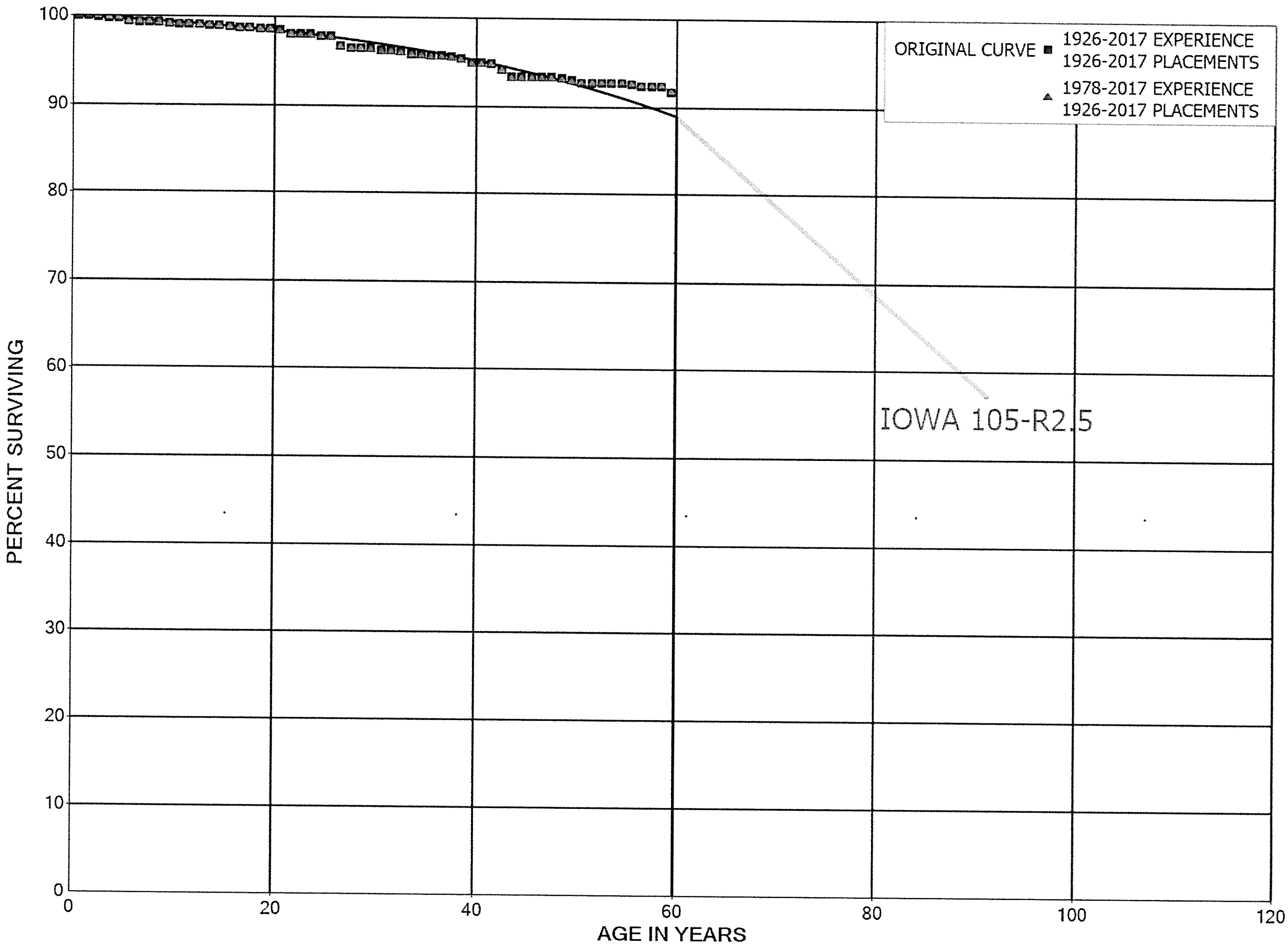
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
314.00 TURBOGENERATOR UNITS								
TRIMBLE COUNTY UNIT 2	60-R2 *	(13)	89,986,324.04	21,764,667	79,919,879	1,925,583	2.14	41.5
BROWN UNIT 1	60-R2 *	(6)	11,380,919.20	11,727,960	335,814	287,021	2.52	1.2
BROWN UNIT 2	60-R2 *	(6)	13,703,060.56	14,265,275	259,969	222,196	1.62	1.2
BROWN UNIT 3	60-R2 *	(6)	45,797,249.49	8,377,637	40,167,447	2,422,680	5.29	16.6
GHENT UNIT 1	60-R2 *	(8)	40,327,741.42	22,388,069	21,165,892	1,346,312	3.34	15.7
GHENT UNIT 2	60-R2 *	(8)	33,056,975.75	22,423,578	13,277,956	866,909	2.62	15.3
GHENT UNIT 3	60-R2 *	(8)	43,859,372.17	30,697,120	16,671,002	931,474	2.12	17.9
GHENT UNIT 4	60-R2 *	(8)	59,231,536.72	34,540,570	29,429,490	1,561,503	2.64	18.8
TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS			337,343,179.35	166,184,876	201,227,449	9,563,678	2.83	21.0
315.00 ACCESSORY ELECTRIC EQUIPMENT								
TRIMBLE COUNTY UNIT 2	70-R4 *	(13)	45,619,554.81	9,925,988	41,624,109	907,424	1.99	45.9
TRIMBLE COUNTY UNIT 2 SCRUBBER	70-R4 *	(13)	1,415,469.10	793,978	805,502	20,168	1.42	39.9
BROWN UNIT 1	70-R4 *	(6)	4,321,324.05	4,517,823	62,780	53,659	1.24	1.2
BROWN UNIT 2	70-R4 *	(6)	2,416,429.81	2,504,751	56,665	48,431	2.00	1.2
BROWN UNIT 3	70-R4 *	(6)	15,435,528.73	6,347,369	10,014,291	577,283	3.74	17.3
BROWN UNIT 1, 2 AND 3 SCRUBBER	70-R4 *	(6)	29,324,457.10	6,736,824	24,347,101	1,392,854	4.75	17.5
GHENT UNIT 1 SCRUBBER	70-R4 *	(8)	12,223,379.51	5,766,682	7,434,568	451,449	3.69	16.5
GHENT UNIT 1	70-R4 *	(8)	12,336,881.42	8,571,504	4,752,328	292,365	2.37	16.3
GHENT UNIT 2	70-R4 *	(8)	14,213,740.74	11,578,763	3,772,077	236,021	1.66	16.0
GHENT UNIT 3	70-R4 *	(8)	33,564,209.82	25,293,521	10,955,826	582,236	1.73	18.8
GHENT UNIT 4	70-R4 *	(8)	52,184,797.21	18,816,313	37,543,268	1,855,228	3.56	20.2
GHENT UNIT 2 SCRUBBER	70-R4 *	(8)	951,198.87	266,709	760,586	46,150	4.85	16.5
GHENT UNIT 3 SCRUBBER	70-R4 *	(8)	12,041,998.28	4,433,095	8,572,263	440,911	3.66	19.4
GHENT UNIT 4 SCRUBBER	70-R4 *	(8)	15,148,041.55	3,480,348	12,879,537	629,191	4.15	20.5
TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT			251,197,011.00	109,033,668	163,580,901	7,533,370	3.00	21.7
316.00 MISCELLANEOUS PLANT EQUIPMENT								
TRIMBLE COUNTY UNIT 2	75-R1.5 *	(13)	7,002,702.79	1,014,150	6,898,904	158,008	2.26	43.7
SYSTEM LABORATORY	75-R1.5 *	0	3,688,912.98	933,650	2,755,263	127,717	3.46	21.6
BROWN UNIT 1	75-R1.5 *	(6)	389,684.21	406,185	6,880	5,931	1.52	1.2
BROWN UNIT 2	75-R1.5 *	(6)	123,107.10	130,414	80	69	0.06	1.2
BROWN UNIT 3	75-R1.5 *	(6)	6,483,855.33	3,197,454	3,675,433	217,739	3.36	16.9
GHENT UNIT 1 SCRUBBER	75-R1.5 *	(8)	962,012.25	900,830	138,143	8,684	0.90	15.9
GHENT UNIT 1	75-R1.5 *	(8)	1,845,970.85	1,684,463	309,186	19,534	1.06	15.8
GHENT UNIT 2	75-R1.5 *	(8)	1,553,509.99	1,460,824	216,967	13,868	0.89	15.6
GHENT UNIT 3	75-R1.5 *	(8)	4,027,500.01	2,729,825	1,619,875	87,351	2.17	18.5
GHENT UNIT 4	75-R1.5 *	(8)	9,999,060.73	3,857,934	6,941,052	353,380	3.53	19.6
TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT			36,076,316.24	16,315,729	22,561,783	992,281	2.75	22.7
TOTAL STEAM PRODUCTION PLANT			**4,946,630,275.19**	**1,678,583,978**	**3,679,413,641**	**192,147,389**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

PART VII. SERVICE LIFE STATISTICS

KENTUCKY UTILITIES COMPANY
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	358,518,587		0.0000	1.0000	100.00
0.5	351,924,916	5,735	0.0000	1.0000	100.00
1.5	328,708,696	542,452	0.0017	0.9983	100.00
2.5	315,469,873	186,540	0.0006	0.9994	99.83
3.5	295,009,739	50,433	0.0002	0.9998	99.77
4.5	246,487,512	892,904	0.0036	0.9964	99.76
5.5	243,542,184	151,374	0.0006	0.9994	99.40
6.5	183,713,875	21,095	0.0001	0.9999	99.33
7.5	181,393,884	167,151	0.0009	0.9991	99.32
8.5	180,443,088	170,873	0.0009	0.9991	99.23
9.5	179,882,605	39,157	0.0002	0.9998	99.14
10.5	162,876,515	27,824	0.0002	0.9998	99.12
11.5	162,624,174	27,779	0.0002	0.9998	99.10
12.5	145,848,932	154,244	0.0011	0.9989	99.08
13.5	142,441,493	120,680	0.0008	0.9992	98.98
14.5	142,016,095	118,767	0.0008	0.9992	98.89
15.5	157,096,352	64,102	0.0004	0.9996	98.81
16.5	155,914,569	78,589	0.0005	0.9995	98.77
17.5	155,523,308	109,268	0.0007	0.9993	98.72
18.5	155,346,066	62,571	0.0004	0.9996	98.65
19.5	154,987,568	206,911	0.0013	0.9987	98.61
20.5	143,402,327	580,656	0.0040	0.9960	98.48
21.5	187,437,754	106,129	0.0006	0.9994	98.08
22.5	186,832,000	15,619	0.0001	0.9999	98.03
23.5	170,218,360	232,862	0.0014	0.9986	98.02
24.5	169,366,818	175,871	0.0010	0.9990	97.88
25.5	168,105,725	1,787,256	0.0106	0.9894	97.78
26.5	161,493,737	306,243	0.0019	0.9981	96.74
27.5	120,744,487	17,931	0.0001	0.9999	96.56
28.5	119,429,170	61,674	0.0005	0.9995	96.54
29.5	118,796,303	298,696	0.0025	0.9975	96.49
30.5	115,686,197	3,716	0.0000	1.0000	96.25
31.5	112,904,819	114,710	0.0010	0.9990	96.25
32.5	111,638,165	307,859	0.0028	0.9972	96.15
33.5	95,247,801	87,047	0.0009	0.9991	95.89
34.5	95,146,045	41,008	0.0004	0.9996	95.80
35.5	93,353,668	77,282	0.0008	0.9992	95.76
36.5	58,530,613	44,328	0.0008	0.9992	95.68
37.5	58,057,903	111,949	0.0019	0.9981	95.60
38.5	57,138,911	262,133	0.0046	0.9954	95.42

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	56,794,416		0.0000	1.0000	94.98
40.5	40,448,823	63,504	0.0016	0.9984	94.98
41.5	40,385,319	270,668	0.0067	0.9933	94.83
42.5	39,696,986	344,462	0.0087	0.9913	94.20
43.5	24,909,022		0.0000	1.0000	93.38
44.5	24,883,859		0.0000	1.0000	93.38
45.5	24,815,328	5,000	0.0002	0.9998	93.38
46.5	17,322,875	2,942	0.0002	0.9998	93.36
47.5	17,304,689	17,705	0.0010	0.9990	93.35
48.5	17,283,856	35,694	0.0021	0.9979	93.25
49.5	17,231,852	60,621	0.0035	0.9965	93.06
50.5	17,167,131		0.0000	1.0000	92.73
51.5	16,395,544	1,141	0.0001	0.9999	92.73
52.5	16,375,513		0.0000	1.0000	92.72
53.5	16,373,692	9,523	0.0006	0.9994	92.72
54.5	13,953,787	13,326	0.0010	0.9990	92.67
55.5	13,906,348	30,823	0.0022	0.9978	92.58
56.5	13,642,481	829	0.0001	0.9999	92.38
57.5	13,620,945	1,385	0.0001	0.9999	92.37
58.5	11,482,732	82,243	0.0072	0.9928	92.36
59.5	11,376,042	943	0.0001	0.9999	91.70
60.5	9,789,416		0.0000	1.0000	91.69
61.5	7,235,866		0.0000	1.0000	91.69
62.5	7,182,368		0.0000	1.0000	91.69
63.5	5,617,756		0.0000	1.0000	91.69
64.5	5,297,850		0.0000	1.0000	91.69
65.5	4,606,841		0.0000	1.0000	91.69
66.5	3,367,891		0.0000	1.0000	91.69
67.5	2,386,014	11,983	0.0050	0.9950	91.69
68.5	2,370,273		0.0000	1.0000	91.23
69.5	2,065,836		0.0000	1.0000	91.23
70.5	1,041,808		0.0000	1.0000	91.23
71.5	1,041,808		0.0000	1.0000	91.23
72.5	1,041,808		0.0000	1.0000	91.23
73.5	1,041,808		0.0000	1.0000	91.23
74.5	1,041,808		0.0000	1.0000	91.23
75.5	1,041,808		0.0000	1.0000	91.23
76.5					91.23

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	299,600,037		0.0000	1.0000	100.00
0.5	310,488,444	5,735	0.0000	1.0000	100.00
1.5	287,321,240	542,452	0.0019	0.9981	100.00
2.5	274,726,156	186,540	0.0007	0.9993	99.81
3.5	269,204,050	50,433	0.0002	0.9998	99.74
4.5	220,709,661	867,876	0.0039	0.9961	99.72
5.5	218,028,572	142,045	0.0007	0.9993	99.33
6.5	165,915,832	21,095	0.0001	0.9999	99.27
7.5	163,705,191	167,151	0.0010	0.9990	99.25
8.5	162,787,096	170,873	0.0010	0.9990	99.15
9.5	162,229,923	35,941	0.0002	0.9998	99.05
10.5	145,245,245	18,151	0.0001	0.9999	99.03
11.5	145,014,156	27,779	0.0002	0.9998	99.01
12.5	128,259,088	135,057	0.0011	0.9989	98.99
13.5	124,903,848	120,680	0.0010	0.9990	98.89
14.5	125,758,862	118,767	0.0009	0.9991	98.79
15.5	140,839,120	64,102	0.0005	0.9995	98.70
16.5	139,677,521	77,268	0.0006	0.9994	98.66
17.5	139,344,819	107,012	0.0008	0.9992	98.60
18.5	141,554,132	62,571	0.0004	0.9996	98.53
19.5	141,276,145	206,911	0.0015	0.9985	98.48
20.5	129,690,904	579,229	0.0045	0.9955	98.34
21.5	176,232,830	106,129	0.0006	0.9994	97.90
22.5	175,667,733	15,619	0.0001	0.9999	97.84
23.5	160,832,895	232,862	0.0014	0.9986	97.83
24.5	161,850,851	122,952	0.0008	0.9992	97.69
25.5	160,642,956	1,737,271	0.0108	0.9892	97.62
26.5	154,905,635	306,243	0.0020	0.9980	96.56
27.5	116,958,729	17,931	0.0002	0.9998	96.37
28.5	115,682,950	61,174	0.0005	0.9995	96.35
29.5	115,412,545	298,696	0.0026	0.9974	96.30
30.5	114,519,665	3,716	0.0000	1.0000	96.05
31.5	111,738,287	114,710	0.0010	0.9990	96.05
32.5	110,471,633	307,859	0.0028	0.9972	95.95
33.5	94,081,269	87,047	0.0009	0.9991	95.69
34.5	93,979,513	41,008	0.0004	0.9996	95.60
35.5	92,187,136	77,282	0.0008	0.9992	95.56
36.5	57,364,081	44,328	0.0008	0.9992	95.47
37.5	56,891,371	111,949	0.0020	0.9980	95.40
38.5	55,995,116	262,133	0.0047	0.9953	95.21

KENTUCKY UTILITIES COMPANY

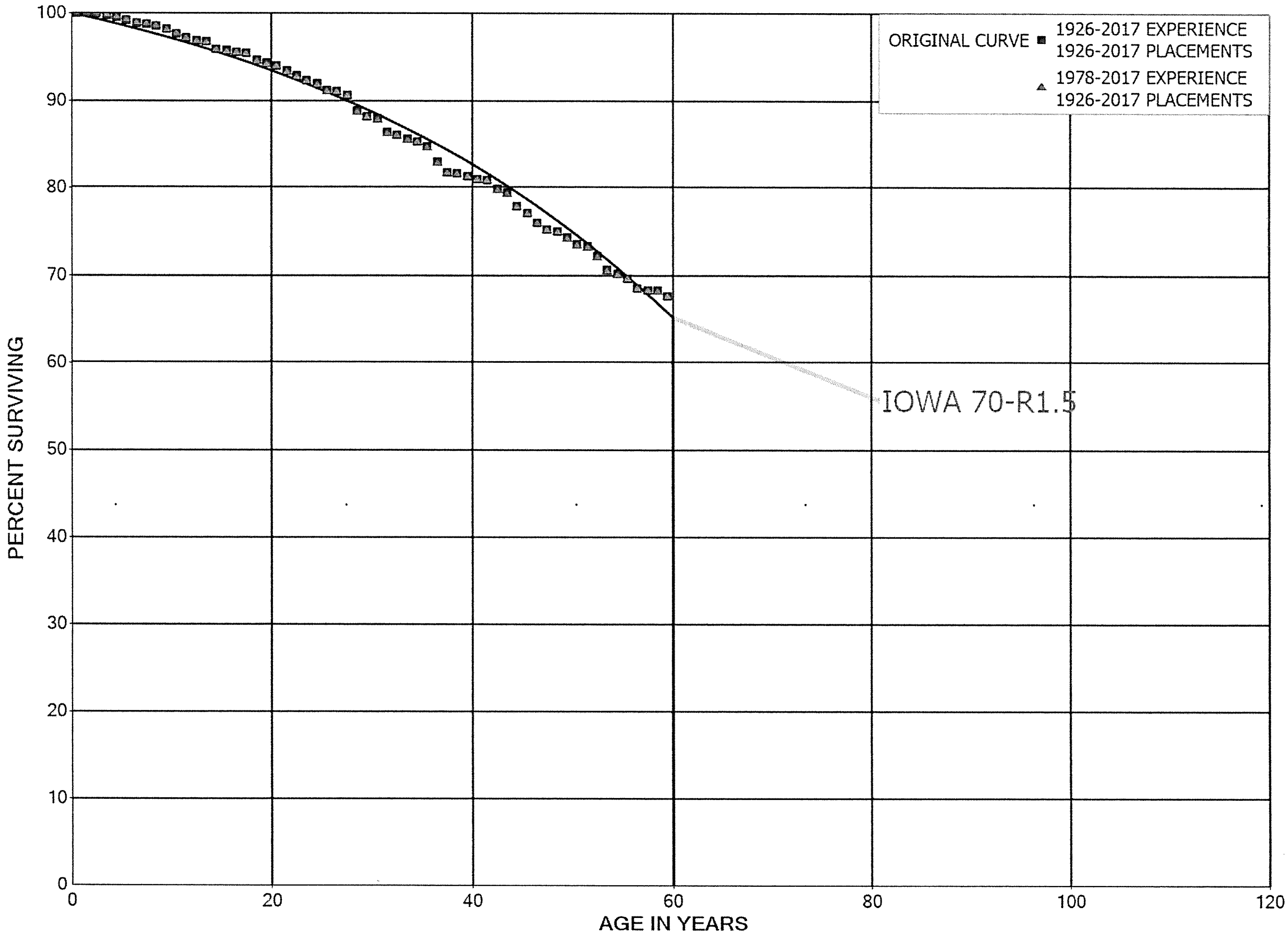
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	55,650,621		0.0000	1.0000	94.77
40.5	39,305,028	33,715	0.0009	0.9991	94.77
41.5	39,271,313	270,668	0.0069	0.9931	94.69
42.5	38,582,980	344,462	0.0089	0.9911	94.03
43.5	23,795,016		0.0000	1.0000	93.19
44.5	23,769,853		0.0000	1.0000	93.19
45.5	23,701,322		0.0000	1.0000	93.19
46.5	16,213,869	2,942	0.0002	0.9998	93.19
47.5	16,195,683	17,705	0.0011	0.9989	93.18
48.5	16,174,850	35,694	0.0022	0.9978	93.08
49.5	16,122,846	18,423	0.0011	0.9989	92.87
50.5	16,100,323		0.0000	1.0000	92.76
51.5	16,395,544	1,141	0.0001	0.9999	92.76
52.5	16,375,513		0.0000	1.0000	92.76
53.5	16,373,692	9,523	0.0006	0.9994	92.76
54.5	13,953,787	13,326	0.0010	0.9990	92.70
55.5	13,906,348	30,823	0.0022	0.9978	92.62
56.5	13,642,481	829	0.0001	0.9999	92.41
57.5	13,620,945	1,385	0.0001	0.9999	92.40
58.5	11,482,732	82,243	0.0072	0.9928	92.39
59.5	11,376,042	943	0.0001	0.9999	91.73
60.5	9,789,416		0.0000	1.0000	91.73
61.5	7,235,866		0.0000	1.0000	91.73
62.5	7,182,368		0.0000	1.0000	91.73
63.5	5,617,756		0.0000	1.0000	91.73
64.5	5,297,850		0.0000	1.0000	91.73
65.5	4,606,841		0.0000	1.0000	91.73
66.5	3,367,891		0.0000	1.0000	91.73
67.5	2,386,014	11,983	0.0050	0.9950	91.73
68.5	2,370,273		0.0000	1.0000	91.26
69.5	2,065,836		0.0000	1.0000	91.26
70.5	1,041,808		0.0000	1.0000	91.26
71.5	1,041,808		0.0000	1.0000	91.26
72.5	1,041,808		0.0000	1.0000	91.26
73.5	1,041,808		0.0000	1.0000	91.26
74.5	1,041,808		0.0000	1.0000	91.26
75.5	1,041,808		0.0000	1.0000	91.26
76.5					91.26

KENTUCKY UTILITIES COMPANY
ACCOUNT 312 BOILER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,159,160,426	628,572	0.0002	0.9998	100.00
0.5	4,102,565,263	73,861	0.0000	1.0000	99.98
1.5	3,983,390,994	2,670,287	0.0007	0.9993	99.98
2.5	3,576,555,643	8,372,094	0.0023	0.9977	99.92
3.5	2,920,023,261	5,297,148	0.0018	0.9982	99.68
4.5	2,542,611,810	8,847,635	0.0035	0.9965	99.50
5.5	1,898,389,862	5,321,171	0.0028	0.9972	99.16
6.5	1,320,175,658	1,613,167	0.0012	0.9988	98.88
7.5	1,255,324,757	2,600,881	0.0021	0.9979	98.76
8.5	1,224,744,277	4,930,048	0.0040	0.9960	98.55
9.5	1,193,168,148	6,014,361	0.0050	0.9950	98.16
10.5	1,060,904,142	5,829,846	0.0055	0.9945	97.66
11.5	1,036,359,392	3,358,366	0.0032	0.9968	97.12
12.5	952,096,033	1,082,835	0.0011	0.9989	96.81
13.5	750,877,056	6,642,177	0.0088	0.9912	96.70
14.5	735,574,350	1,152,589	0.0016	0.9984	95.84
15.5	775,689,957	1,433,490	0.0018	0.9982	95.69
16.5	766,312,885	1,048,295	0.0014	0.9986	95.52
17.5	764,470,085	6,401,936	0.0084	0.9916	95.39
18.5	751,319,521	2,630,376	0.0035	0.9965	94.59
19.5	746,195,650	2,501,448	0.0034	0.9966	94.26
20.5	704,753,222	4,309,440	0.0061	0.9939	93.94
21.5	737,940,907	4,218,001	0.0057	0.9943	93.37
22.5	721,374,095	3,867,817	0.0054	0.9946	92.83
23.5	629,563,724	2,903,728	0.0046	0.9954	92.33
24.5	607,766,242	4,688,331	0.0077	0.9923	91.91
25.5	589,984,333	940,249	0.0016	0.9984	91.20
26.5	581,255,942	2,874,827	0.0049	0.9951	91.05
27.5	530,070,177	10,521,562	0.0198	0.9802	90.60
28.5	517,310,244	3,369,517	0.0065	0.9935	88.80
29.5	508,837,169	1,852,641	0.0036	0.9964	88.23
30.5	503,872,687	8,746,216	0.0174	0.9826	87.91
31.5	493,560,467	1,591,460	0.0032	0.9968	86.38
32.5	491,681,469	2,973,812	0.0060	0.9940	86.10
33.5	354,672,584	1,008,415	0.0028	0.9972	85.58
34.5	353,090,051	2,616,046	0.0074	0.9926	85.34
35.5	343,993,127	7,279,466	0.0212	0.9788	84.70
36.5	206,709,645	2,826,368	0.0137	0.9863	82.91
37.5	202,021,484	357,029	0.0018	0.9982	81.78
38.5	193,547,312	705,265	0.0036	0.9964	81.63

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	190,357,746	805,630	0.0042	0.9958	81.34
40.5	127,569,712	185,770	0.0015	0.9985	80.99
41.5	115,979,194	1,510,705	0.0130	0.9870	80.87
42.5	109,909,164	654,781	0.0060	0.9940	79.82
43.5	59,060,708	1,095,896	0.0186	0.9814	79.35
44.5	56,152,378	549,870	0.0098	0.9902	77.87
45.5	55,189,645	815,815	0.0148	0.9852	77.11
46.5	30,839,865	318,881	0.0103	0.9897	75.97
47.5	30,506,677	83,359	0.0027	0.9973	75.19
48.5	30,409,129	293,407	0.0096	0.9904	74.98
49.5	30,112,180	310,091	0.0103	0.9897	74.26
50.5	29,790,936	87,355	0.0029	0.9971	73.49
51.5	27,790,332	432,169	0.0156	0.9844	73.28
52.5	27,328,258	590,281	0.0216	0.9784	72.14
53.5	26,654,042	152,249	0.0057	0.9943	70.58
54.5	18,013,474	132,553	0.0074	0.9926	70.18
55.5	17,879,094	288,131	0.0161	0.9839	69.66
56.5	13,793,187	49,273	0.0036	0.9964	68.54
57.5	13,710,633	11,088	0.0008	0.9992	68.29
58.5	13,686,544	123,614	0.0090	0.9910	68.24
59.5	11,898,476		0.0000	1.0000	67.62
60.5	7,471,926	46,504	0.0062	0.9938	67.62
61.5	565,974	18,726	0.0331	0.9669	67.20
62.5	546,419		0.0000	1.0000	64.98
63.5	546,419	56,616	0.1036	0.8964	64.98
64.5	489,803		0.0000	1.0000	58.24
65.5	407,486	235,381	0.5776	0.4224	58.24
66.5	166,261		0.0000	1.0000	24.60
67.5	127,433		0.0000	1.0000	24.60
68.5	127,433		0.0000	1.0000	24.60
69.5	127,433		0.0000	1.0000	24.60
70.5	127,433		0.0000	1.0000	24.60
71.5	127,433		0.0000	1.0000	24.60
72.5	127,433		0.0000	1.0000	24.60
73.5	127,433		0.0000	1.0000	24.60
74.5	127,433		0.0000	1.0000	24.60
75.5	127,433		0.0000	1.0000	24.60
76.5					24.60

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,918,084,638	563,333	0.0001	0.9999	100.00
0.5	3,937,027,303	63,679	0.0000	1.0000	99.99
1.5	3,826,869,212	2,670,287	0.0007	0.9993	99.98
2.5	3,432,350,876	8,261,305	0.0024	0.9976	99.91
3.5	2,843,684,961	5,289,712	0.0019	0.9981	99.67
4.5	2,469,845,390	8,821,493	0.0036	0.9964	99.49
5.5	1,827,605,232	5,321,171	0.0029	0.9971	99.13
6.5	1,282,694,112	1,602,217	0.0012	0.9988	98.84
7.5	1,218,086,501	2,600,881	0.0021	0.9979	98.72
8.5	1,187,527,918	4,885,279	0.0041	0.9959	98.51
9.5	1,156,009,559	6,008,235	0.0052	0.9948	98.10
10.5	1,023,765,869	5,778,138	0.0056	0.9944	97.59
11.5	999,317,632	3,323,366	0.0033	0.9967	97.04
12.5	915,139,091	1,064,979	0.0012	0.9988	96.72
13.5	714,047,233	6,623,097	0.0093	0.9907	96.61
14.5	705,833,450	1,139,041	0.0016	0.9984	95.71
15.5	745,962,604	1,387,304	0.0019	0.9981	95.56
16.5	736,631,719	1,030,251	0.0014	0.9986	95.38
17.5	734,816,007	6,235,301	0.0085	0.9915	95.25
18.5	727,251,508	2,615,262	0.0036	0.9964	94.44
19.5	722,452,318	2,435,670	0.0034	0.9966	94.10
20.5	681,944,735	4,262,079	0.0062	0.9938	93.78
21.5	720,039,405	4,188,824	0.0058	0.9942	93.20
22.5	703,511,416	3,838,884	0.0055	0.9945	92.65
23.5	615,474,137	2,903,728	0.0047	0.9953	92.15
24.5	597,282,266	4,663,795	0.0078	0.9922	91.71
25.5	579,555,624	578,270	0.0010	0.9990	91.00
26.5	573,171,153	2,865,527	0.0050	0.9950	90.91
27.5	525,929,611	10,515,735	0.0200	0.9800	90.45
28.5	513,232,121	3,369,517	0.0066	0.9934	88.64
29.5	506,376,596	1,852,029	0.0037	0.9963	88.06
30.5	502,669,808	8,725,800	0.0174	0.9826	87.74
31.5	492,378,004	1,591,460	0.0032	0.9968	86.22
32.5	490,499,492	2,973,812	0.0061	0.9939	85.94
33.5	353,490,607	1,008,415	0.0029	0.9971	85.42
34.5	351,908,074	2,616,046	0.0074	0.9926	85.17
35.5	342,811,150	7,279,466	0.0212	0.9788	84.54
36.5	205,527,668	2,826,368	0.0138	0.9862	82.74
37.5	200,839,507	357,029	0.0018	0.9982	81.61
38.5	193,419,879	705,265	0.0036	0.9964	81.46

KENTUCKY UTILITIES COMPANY

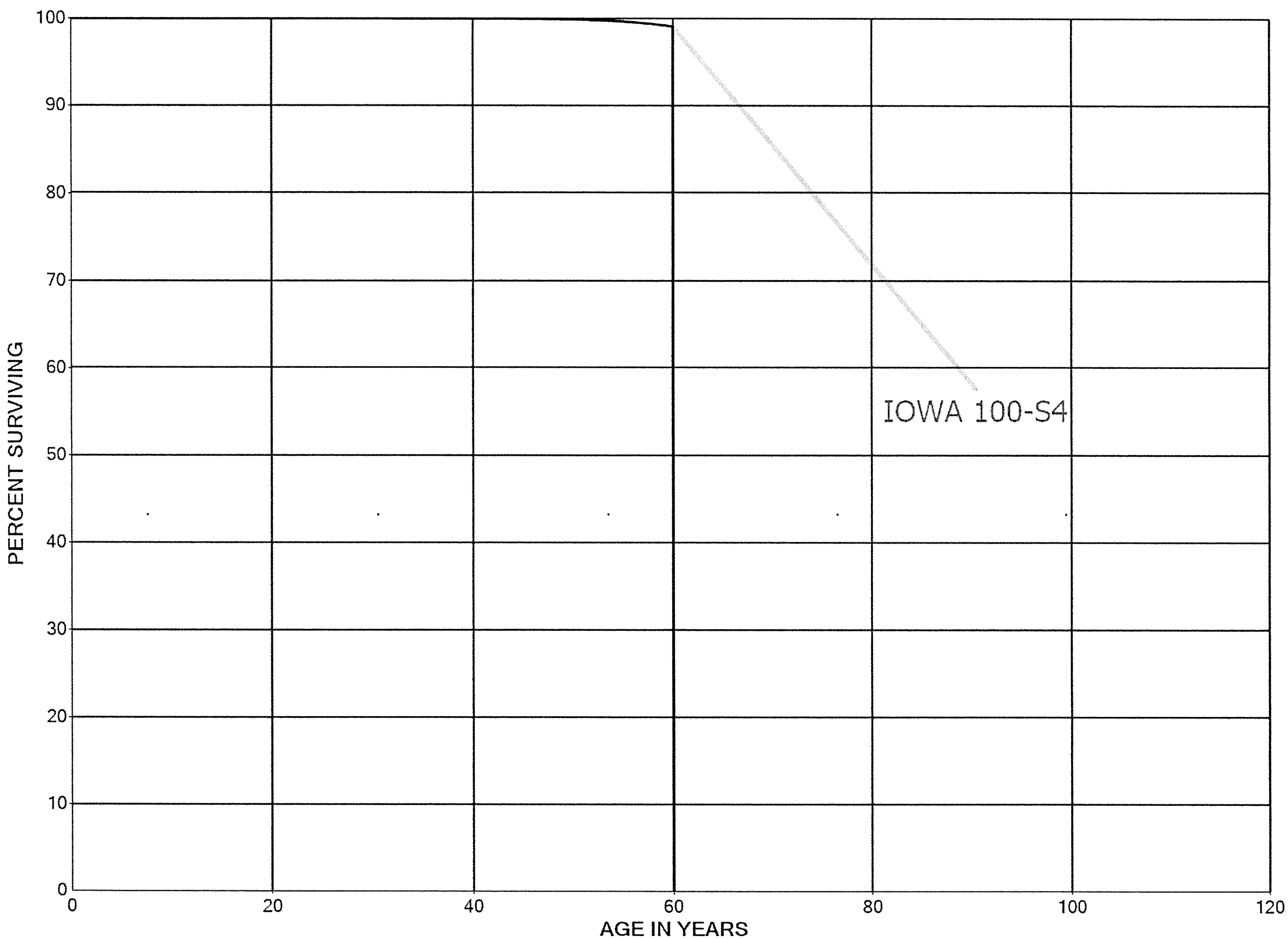
ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

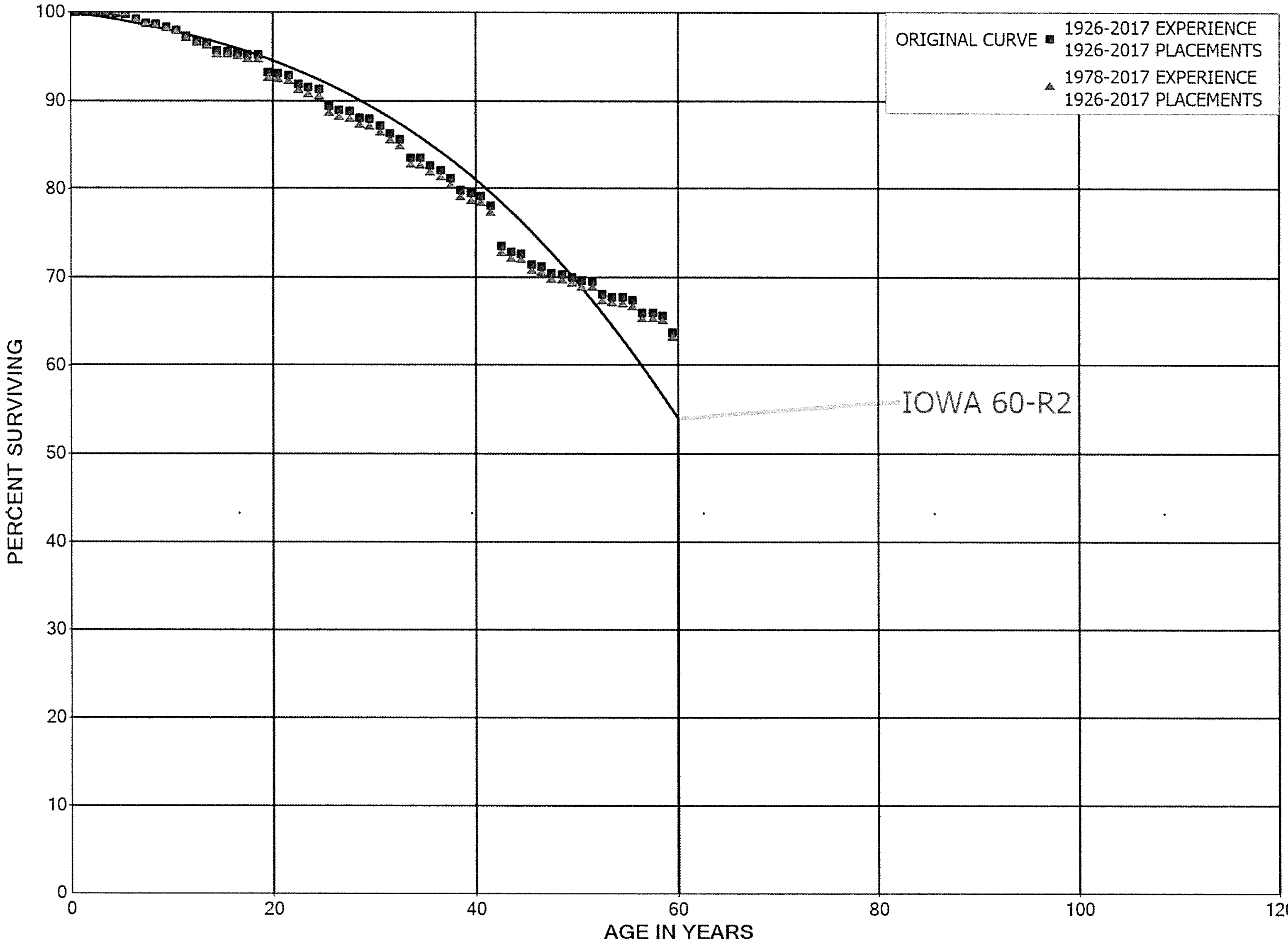
PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	190,230,313	805,630	0.0042	0.9958	81.16
40.5	127,442,279	185,770	0.0015	0.9985	80.82
41.5	115,851,761	1,510,705	0.0130	0.9870	80.70
42.5	109,781,731	654,781	0.0060	0.9940	79.65
43.5	58,933,275	1,095,896	0.0186	0.9814	79.18
44.5	56,024,945	549,870	0.0098	0.9902	77.70
45.5	55,062,212	815,815	0.0148	0.9852	76.94
46.5	30,712,432	318,881	0.0104	0.9896	75.80
47.5	30,379,244	83,359	0.0027	0.9973	75.01
48.5	30,281,696	293,407	0.0097	0.9903	74.81
49.5	29,984,747	310,091	0.0103	0.9897	74.08
50.5	29,663,503	87,355	0.0029	0.9971	73.32
51.5	27,790,332	432,169	0.0156	0.9844	73.10
52.5	27,328,258	590,281	0.0216	0.9784	71.96
53.5	26,654,042	152,249	0.0057	0.9943	70.41
54.5	18,013,474	132,553	0.0074	0.9926	70.01
55.5	17,879,094	288,131	0.0161	0.9839	69.49
56.5	13,793,187	49,273	0.0036	0.9964	68.37
57.5	13,710,633	11,088	0.0008	0.9992	68.13
58.5	13,686,544	123,614	0.0090	0.9910	68.07
59.5	11,898,476		0.0000	1.0000	67.46
60.5	7,471,926	46,504	0.0062	0.9938	67.46
61.5	565,974	18,726	0.0331	0.9669	67.04
62.5	546,419		0.0000	1.0000	64.82
63.5	546,419	56,616	0.1036	0.8964	64.82
64.5	489,803		0.0000	1.0000	58.10
65.5	407,486	235,381	0.5776	0.4224	58.10
66.5	166,261		0.0000	1.0000	24.54
67.5	127,433		0.0000	1.0000	24.54
68.5	127,433		0.0000	1.0000	24.54
69.5	127,433		0.0000	1.0000	24.54
70.5	127,433		0.0000	1.0000	24.54
71.5	127,433		0.0000	1.0000	24.54
72.5	127,433		0.0000	1.0000	24.54
73.5	127,433		0.0000	1.0000	24.54
74.5	127,433		0.0000	1.0000	24.54
75.5	127,433		0.0000	1.0000	24.54
76.5					24.54

KENTUCKY UTILITIES COMPANY
ACCOUNT 312.1 BOILER PLANT EQUIPMENT - ASH PONDS
SMOOTH SURVIVOR CURVE



KENTUCKY UTILITIES COMPANY
ACCOUNT 314 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	387,725,214		0.0000	1.0000	100.00
0.5	381,139,714		0.0000	1.0000	100.00
1.5	377,024,441	11,405	0.0000	1.0000	100.00
2.5	366,972,073	134,051	0.0004	0.9996	100.00
3.5	369,243,964	480,666	0.0013	0.9987	99.96
4.5	364,618,100	214,298	0.0006	0.9994	99.83
5.5	338,511,844	2,099,708	0.0062	0.9938	99.77
6.5	267,811,351	1,122,467	0.0042	0.9958	99.15
7.5	265,677,115	366,895	0.0014	0.9986	98.74
8.5	255,946,338	960,583	0.0038	0.9962	98.60
9.5	231,476,191	612,448	0.0026	0.9974	98.23
10.5	228,911,154	1,663,343	0.0073	0.9927	97.97
11.5	220,734,432	1,152,535	0.0052	0.9948	97.26
12.5	211,958,656	495,156	0.0023	0.9977	96.75
13.5	206,744,669	2,047,398	0.0099	0.9901	96.53
14.5	198,855,521	34,900	0.0002	0.9998	95.57
15.5	196,943,842	371,673	0.0019	0.9981	95.55
16.5	195,741,809	496,466	0.0025	0.9975	95.37
17.5	195,244,667	3,600	0.0000	1.0000	95.13
18.5	189,949,254	3,863,067	0.0203	0.9797	95.13
19.5	185,546,481	335,070	0.0018	0.9982	93.19
20.5	174,311,539	367,194	0.0021	0.9979	93.03
21.5	181,798,746	1,871,499	0.0103	0.9897	92.83
22.5	176,719,003	705,556	0.0040	0.9960	91.87
23.5	172,200,433	449,660	0.0026	0.9974	91.51
24.5	171,538,771	3,527,233	0.0206	0.9794	91.27
25.5	167,953,310	787,410	0.0047	0.9953	89.39
26.5	167,144,409	348,432	0.0021	0.9979	88.97
27.5	156,276,738	1,236,741	0.0079	0.9921	88.79
28.5	154,668,125	304,676	0.0020	0.9980	88.08
29.5	154,363,449	1,256,147	0.0081	0.9919	87.91
30.5	152,939,072	1,627,433	0.0106	0.9894	87.20
31.5	151,154,931	1,126,634	0.0075	0.9925	86.27
32.5	149,329,159	3,695,495	0.0247	0.9753	85.62
33.5	97,401,801	58,664	0.0006	0.9994	83.51
34.5	97,306,760	937,038	0.0096	0.9904	83.46
35.5	95,889,706	645,550	0.0067	0.9933	82.65
36.5	71,520,235	818,379	0.0114	0.9886	82.10
37.5	70,696,428	1,109,198	0.0157	0.9843	81.16
38.5	68,486,755	349,329	0.0051	0.9949	79.88

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	63,818,569	198,474	0.0031	0.9969	79.48
40.5	46,303,642	682,698	0.0147	0.9853	79.23
41.5	45,620,787	2,664,171	0.0584	0.9416	78.06
42.5	42,917,695	412,494	0.0096	0.9904	73.50
43.5	28,807,630	59,844	0.0021	0.9979	72.79
44.5	28,745,409	482,943	0.0168	0.9832	72.64
45.5	28,261,577	97,246	0.0034	0.9966	71.42
46.5	21,538,845	221,501	0.0103	0.9897	71.18
47.5	21,317,345	33,901	0.0016	0.9984	70.45
48.5	21,283,444	118,197	0.0056	0.9944	70.33
49.5	21,159,472	106,372	0.0050	0.9950	69.94
50.5	21,010,641	23,139	0.0011	0.9989	69.59
51.5	19,465,619	418,909	0.0215	0.9785	69.51
52.5	19,020,248	82,920	0.0044	0.9956	68.02
53.5	18,934,135	11,547	0.0006	0.9994	67.72
54.5	12,618,892	63,208	0.0050	0.9950	67.68
55.5	12,555,028	261,631	0.0208	0.9792	67.34
56.5	9,566,731	1,805	0.0002	0.9998	65.94
57.5	9,564,926	38,530	0.0040	0.9960	65.93
58.5	9,511,514	275,161	0.0289	0.9711	65.66
59.5	8,459,169	73,616	0.0087	0.9913	63.76
60.5	5,573,236		0.0000	1.0000	63.21
61.5	96,695		0.0000	1.0000	63.21
62.5	96,695		0.0000	1.0000	63.21
63.5	96,695		0.0000	1.0000	63.21
64.5	96,695	68,206	0.7054	0.2946	63.21
65.5	28,489		0.0000	1.0000	18.62
66.5	28,489		0.0000	1.0000	18.62
67.5	28,489		0.0000	1.0000	18.62
68.5	28,489		0.0000	1.0000	18.62
69.5	28,489		0.0000	1.0000	18.62
70.5	28,489		0.0000	1.0000	18.62
71.5	28,489		0.0000	1.0000	18.62
72.5	28,489		0.0000	1.0000	18.62
73.5	28,489		0.0000	1.0000	18.62
74.5	28,489		0.0000	1.0000	18.62
75.5	28,489		0.0000	1.0000	18.62
76.5					18.62

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	307,782,419		0.0000	1.0000	100.00
0.5	321,891,794		0.0000	1.0000	100.00
1.5	317,776,677	11,405	0.0000	1.0000	100.00
2.5	312,399,690	134,051	0.0004	0.9996	100.00
3.5	330,352,173	480,666	0.0015	0.9985	99.95
4.5	325,728,685	214,298	0.0007	0.9993	99.81
5.5	302,569,441	2,099,708	0.0069	0.9931	99.74
6.5	242,427,874	1,122,467	0.0046	0.9954	99.05
7.5	240,300,992	366,895	0.0015	0.9985	98.59
8.5	230,570,215	960,583	0.0042	0.9958	98.44
9.5	206,113,423	612,448	0.0030	0.9970	98.03
10.5	203,548,386	1,663,343	0.0082	0.9918	97.74
11.5	195,371,665	1,152,535	0.0059	0.9941	96.94
12.5	186,631,654	495,156	0.0027	0.9973	96.37
13.5	181,417,896	2,047,398	0.0113	0.9887	96.11
14.5	178,908,685	34,900	0.0002	0.9998	95.03
15.5	176,997,006	371,673	0.0021	0.9979	95.01
16.5	175,801,839	496,466	0.0028	0.9972	94.81
17.5	175,305,353		0.0000	1.0000	94.54
18.5	174,275,484	3,863,067	0.0222	0.9778	94.54
19.5	169,880,170	331,470	0.0020	0.9980	92.45
20.5	158,648,828	367,194	0.0023	0.9977	92.27
21.5	170,385,312	1,871,499	0.0110	0.9890	92.05
22.5	165,305,569	703,027	0.0043	0.9957	91.04
23.5	163,294,916	449,660	0.0028	0.9972	90.66
24.5	164,953,342	3,508,835	0.0213	0.9787	90.41
25.5	161,422,188	787,410	0.0049	0.9951	88.48
26.5	162,142,671	348,432	0.0021	0.9979	88.05
27.5	153,589,431	1,236,741	0.0081	0.9919	87.86
28.5	151,980,818	304,676	0.0020	0.9980	87.15
29.5	152,521,532	1,251,617	0.0082	0.9918	86.98
30.5	151,852,173	1,627,433	0.0107	0.9893	86.27
31.5	150,068,032	1,126,634	0.0075	0.9925	85.34
32.5	148,242,260	3,695,495	0.0249	0.9751	84.70
33.5	96,314,902	58,664	0.0006	0.9994	82.59
34.5	96,219,861	937,038	0.0097	0.9903	82.54
35.5	94,802,807	645,550	0.0068	0.9932	81.73
36.5	70,433,336	818,379	0.0116	0.9884	81.18
37.5	69,609,529	1,109,198	0.0159	0.9841	80.23
38.5	68,458,266	349,329	0.0051	0.9949	78.96

KENTUCKY UTILITIES COMPANY

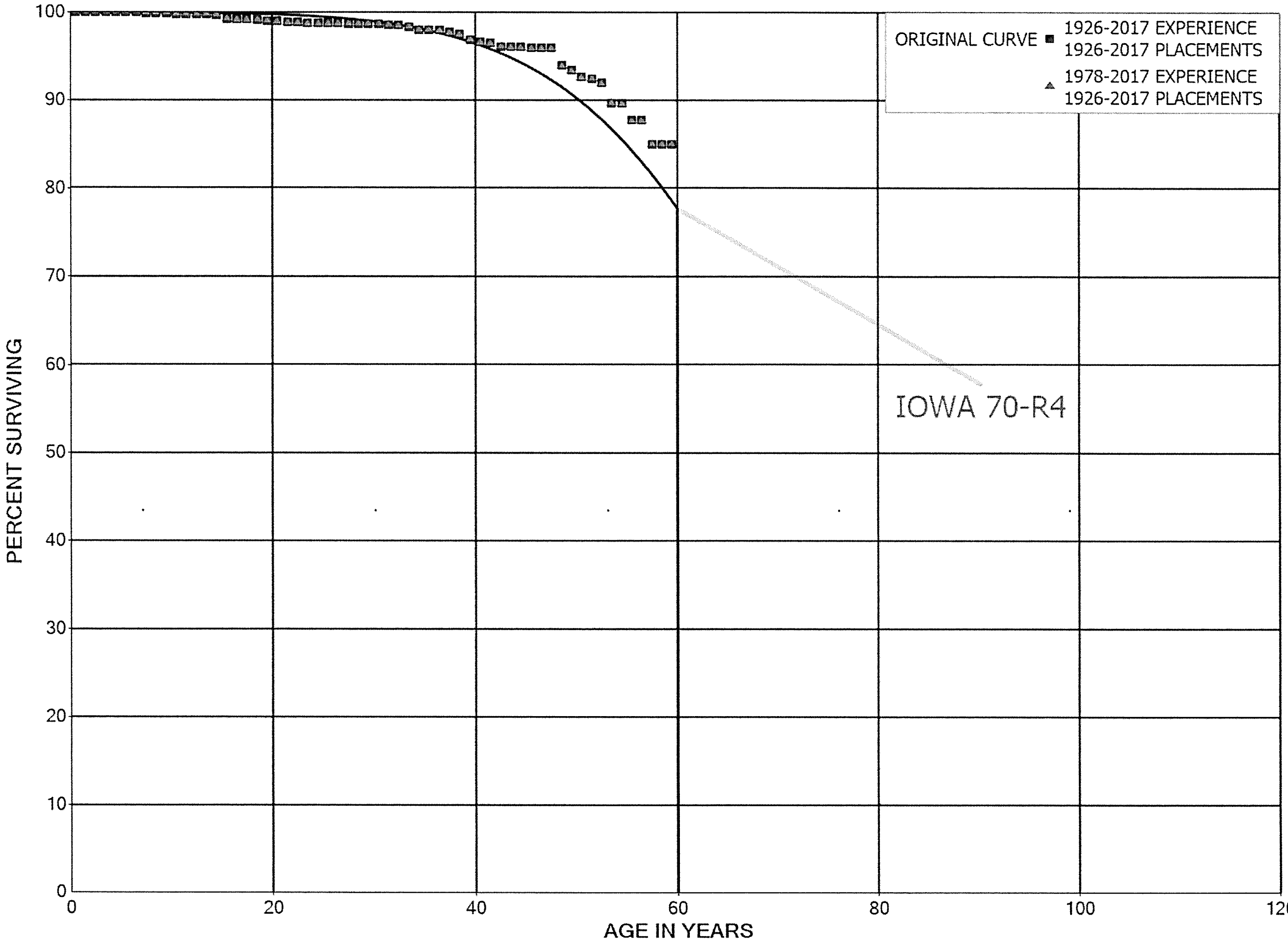
ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	63,790,080	198,474	0.0031	0.9969	78.55
40.5	46,275,153	682,698	0.0148	0.9852	78.31
41.5	45,592,298	2,664,171	0.0584	0.9416	77.15
42.5	42,889,206	412,494	0.0096	0.9904	72.65
43.5	28,779,141	59,844	0.0021	0.9979	71.95
44.5	28,716,920	482,943	0.0168	0.9832	71.80
45.5	28,233,088	97,246	0.0034	0.9966	70.59
46.5	21,510,356	221,501	0.0103	0.9897	70.35
47.5	21,288,856	33,901	0.0016	0.9984	69.62
48.5	21,254,955	118,197	0.0056	0.9944	69.51
49.5	21,130,983	106,372	0.0050	0.9950	69.12
50.5	20,982,152	23,139	0.0011	0.9989	68.78
51.5	19,465,619	418,909	0.0215	0.9785	68.70
52.5	19,020,248	82,920	0.0044	0.9956	67.22
53.5	18,934,135	11,547	0.0006	0.9994	66.93
54.5	12,618,892	63,208	0.0050	0.9950	66.89
55.5	12,555,028	261,631	0.0208	0.9792	66.55
56.5	9,566,731	1,805	0.0002	0.9998	65.17
57.5	9,564,926	38,530	0.0040	0.9960	65.15
58.5	9,511,514	275,161	0.0289	0.9711	64.89
59.5	8,459,169	73,616	0.0087	0.9913	63.01
60.5	5,573,236		0.0000	1.0000	62.47
61.5	96,695		0.0000	1.0000	62.47
62.5	96,695		0.0000	1.0000	62.47
63.5	96,695		0.0000	1.0000	62.47
64.5	96,695	68,206	0.7054	0.2946	62.47
65.5	28,489		0.0000	1.0000	18.40
66.5	28,489		0.0000	1.0000	18.40
67.5	28,489		0.0000	1.0000	18.40
68.5	28,489		0.0000	1.0000	18.40
69.5	28,489		0.0000	1.0000	18.40
70.5	28,489		0.0000	1.0000	18.40
71.5	28,489		0.0000	1.0000	18.40
72.5	28,489		0.0000	1.0000	18.40
73.5	28,489		0.0000	1.0000	18.40
74.5	28,489		0.0000	1.0000	18.40
75.5	28,489		0.0000	1.0000	18.40
76.5					18.40

KENTUCKY UTILITIES COMPANY
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	236,765,620	2,825	0.0000	1.0000	100.00
0.5	231,708,286	60,852	0.0003	0.9997	100.00
1.5	225,886,012	1,251	0.0000	1.0000	99.97
2.5	221,422,167	53,197	0.0002	0.9998	99.97
3.5	194,995,759		0.0000	1.0000	99.95
4.5	164,517,676	19,085	0.0001	0.9999	99.95
5.5	135,305,190	29,193	0.0002	0.9998	99.94
6.5	98,974,416	30,588	0.0003	0.9997	99.91
7.5	98,459,887	61,116	0.0006	0.9994	99.88
8.5	97,775,254	9,673	0.0001	0.9999	99.82
9.5	104,517,017	55,311	0.0005	0.9995	99.81
10.5	90,447,262	16,618	0.0002	0.9998	99.76
11.5	89,641,053	24,289	0.0003	0.9997	99.74
12.5	89,177,905		0.0000	1.0000	99.71
13.5	89,030,022	112,214	0.0013	0.9987	99.71
14.5	88,812,753	366,252	0.0041	0.9959	99.59
15.5	88,446,501	30,424	0.0003	0.9997	99.18
16.5	88,295,371	11,364	0.0001	0.9999	99.14
17.5	81,504,981	43,711	0.0005	0.9995	99.13
18.5	81,461,270	87,989	0.0011	0.9989	99.08
19.5	81,357,650	38,097	0.0005	0.9995	98.97
20.5	77,244,094	77,507	0.0010	0.9990	98.92
21.5	87,735,181	16,906	0.0002	0.9998	98.82
22.5	86,937,871	77,981	0.0009	0.9991	98.81
23.5	85,738,860	4,526	0.0001	0.9999	98.72
24.5	85,519,905	7,439	0.0001	0.9999	98.71
25.5	87,617,079	21,218	0.0002	0.9998	98.70
26.5	87,584,833	15,600	0.0002	0.9998	98.68
27.5	76,914,661	2,400	0.0000	1.0000	98.66
28.5	76,168,176	8,680	0.0001	0.9999	98.66
29.5	76,080,939	21,169	0.0003	0.9997	98.65
30.5	75,990,976	51,076	0.0007	0.9993	98.62
31.5	76,808,216	75,706	0.0010	0.9990	98.55
32.5	76,683,426	137,955	0.0018	0.9982	98.46
33.5	53,447,278	150,784	0.0028	0.9972	98.28
34.5	53,296,494	13,931	0.0003	0.9997	98.00
35.5	52,250,948	40,930	0.0008	0.9992	97.98
36.5	27,162,297	60,283	0.0022	0.9978	97.90
37.5	27,702,446	54,375	0.0020	0.9980	97.68
38.5	27,484,311	175,203	0.0064	0.9936	97.49

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	26,439,415	76,829	0.0029	0.9971	96.87
40.5	16,568,382	18,279	0.0011	0.9989	96.59
41.5	15,910,467	63,328	0.0040	0.9960	96.48
42.5	15,846,566	13,078	0.0008	0.9992	96.10
43.5	9,466,997		0.0000	1.0000	96.02
44.5	9,396,128	8,553	0.0009	0.9991	96.02
45.5	5,179,230		0.0000	1.0000	95.93
46.5	5,410,401	530	0.0001	0.9999	95.93
47.5	5,404,561	109,351	0.0202	0.9798	95.92
48.5	5,569,459	34,150	0.0061	0.9939	93.98
49.5	5,529,355	47,257	0.0085	0.9915	93.40
50.5	5,475,143	10,923	0.0020	0.9980	92.61
51.5	5,151,310	26,194	0.0051	0.9949	92.42
52.5	5,057,986	127,637	0.0252	0.9748	91.95
53.5	4,927,600	3,485	0.0007	0.9993	89.63
54.5	3,014,647	63,419	0.0210	0.9790	89.57
55.5	3,555,458	185	0.0001	0.9999	87.68
56.5	3,040,640	94,142	0.0310	0.9690	87.68
57.5	2,942,091	306	0.0001	0.9999	84.96
58.5	2,925,460		0.0000	1.0000	84.96
59.5	3,067,535	11,578	0.0038	0.9962	84.96
60.5	2,473,101		0.0000	1.0000	84.63
61.5	671,690	883	0.0013	0.9987	84.63
62.5	639,898	9,782	0.0153	0.9847	84.52
63.5	439,626		0.0000	1.0000	83.23
64.5	439,626	65,636	0.1493	0.8507	83.23
65.5	153,727	8,820	0.0574	0.9426	70.80
66.5	144,907		0.0000	1.0000	66.74
67.5	144,907		0.0000	1.0000	66.74
68.5	144,907		0.0000	1.0000	66.74
69.5	144,523		0.0000	1.0000	66.74
70.5	144,523		0.0000	1.0000	66.74
71.5	144,523		0.0000	1.0000	66.74
72.5	144,523		0.0000	1.0000	66.74
73.5	144,523		0.0000	1.0000	66.74
74.5	144,523		0.0000	1.0000	66.74
75.5	144,523		0.0000	1.0000	66.74
76.5					66.74

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	210,281,179		0.0000	1.0000	100.00
0.5	215,399,686	60,852	0.0003	0.9997	100.00
1.5	209,585,266		0.0000	1.0000	99.97
2.5	205,122,672	41,086	0.0002	0.9998	99.97
3.5	185,246,033		0.0000	1.0000	99.95
4.5	154,837,395	19,085	0.0001	0.9999	99.95
5.5	129,774,535	29,193	0.0002	0.9998	99.94
6.5	93,446,113	30,504	0.0003	0.9997	99.92
7.5	92,932,461	55,034	0.0006	0.9994	99.88
8.5	92,253,910	9,673	0.0001	0.9999	99.83
9.5	99,000,875	55,311	0.0006	0.9994	99.81
10.5	84,931,119	16,618	0.0002	0.9998	99.76
11.5	84,125,307	24,289	0.0003	0.9997	99.74
12.5	83,727,163		0.0000	1.0000	99.71
13.5	83,609,405	112,214	0.0013	0.9987	99.71
14.5	84,090,004	366,252	0.0044	0.9956	99.58
15.5	83,723,752	30,424	0.0004	0.9996	99.14
16.5	83,572,621	11,364	0.0001	0.9999	99.11
17.5	76,793,187	43,711	0.0006	0.9994	99.09
18.5	77,355,946	86,930	0.0011	0.9989	99.04
19.5	77,272,677	37,072	0.0005	0.9995	98.93
20.5	73,163,230	77,507	0.0011	0.9989	98.88
21.5	84,642,261	16,906	0.0002	0.9998	98.77
22.5	83,852,827	77,981	0.0009	0.9991	98.75
23.5	83,190,019	4,526	0.0001	0.9999	98.66
24.5	84,090,545		0.0000	1.0000	98.66
25.5	86,201,755	21,218	0.0002	0.9998	98.66
26.5	86,489,345	15,600	0.0002	0.9998	98.63
27.5	76,397,351		0.0000	1.0000	98.61
28.5	75,653,266	8,680	0.0001	0.9999	98.61
29.5	75,706,049	21,169	0.0003	0.9997	98.60
30.5	75,714,843	51,076	0.0007	0.9993	98.58
31.5	76,553,335	75,706	0.0010	0.9990	98.51
32.5	76,428,545	137,955	0.0018	0.9982	98.41
33.5	53,192,397	150,784	0.0028	0.9972	98.23
34.5	53,041,613	13,931	0.0003	0.9997	97.96
35.5	51,996,067	40,930	0.0008	0.9992	97.93
36.5	26,907,416	60,283	0.0022	0.9978	97.85
37.5	27,447,565	54,375	0.0020	0.9980	97.63
38.5	27,334,430	175,203	0.0064	0.9936	97.44

KENTUCKY UTILITIES COMPANY

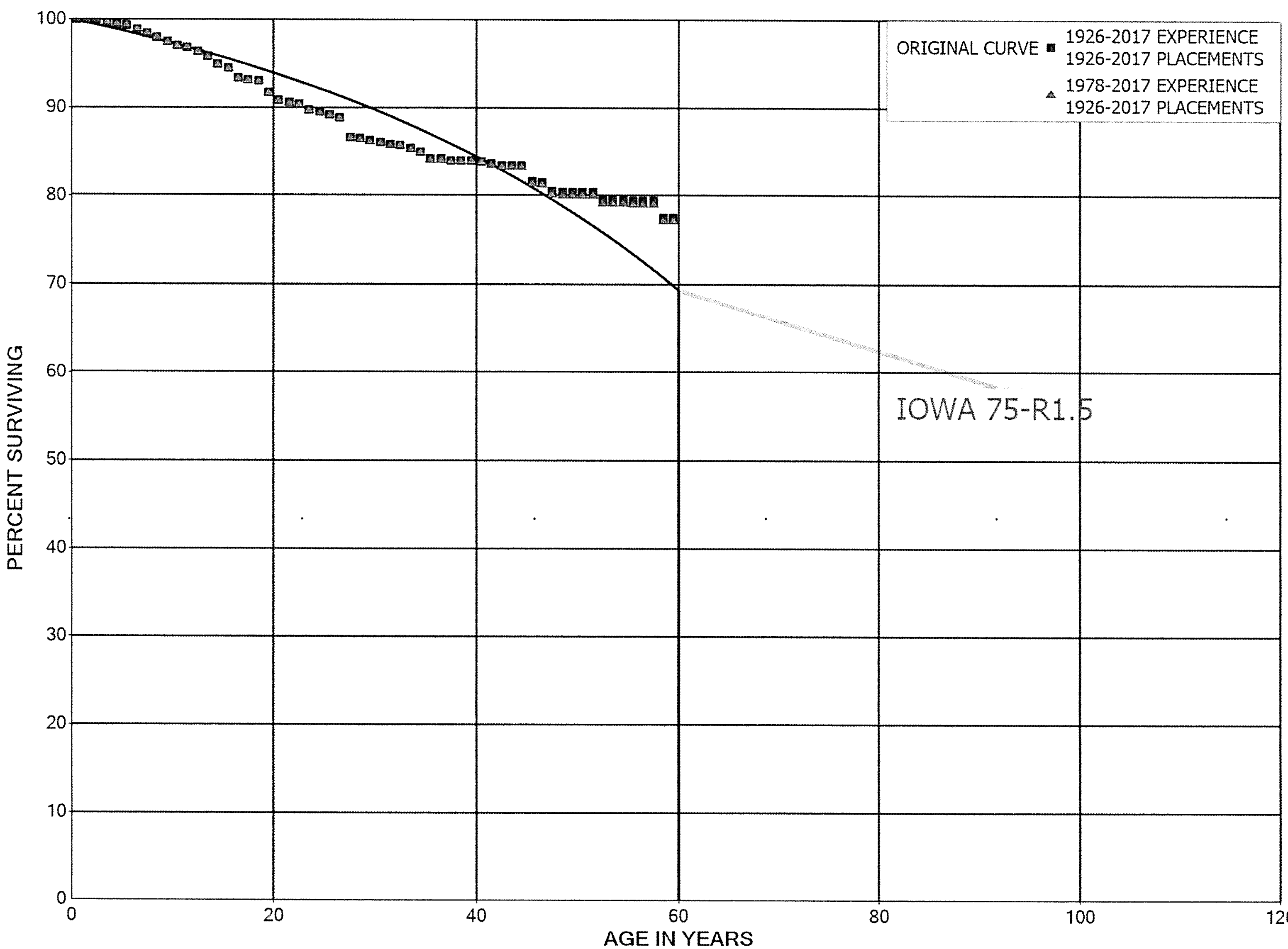
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	26,289,534	76,829	0.0029	0.9971	96.82
40.5	16,418,501	18,279	0.0011	0.9989	96.53
41.5	15,760,586	63,328	0.0040	0.9960	96.43
42.5	15,696,685	13,078	0.0008	0.9992	96.04
43.5	9,317,116		0.0000	1.0000	95.96
44.5	9,246,247	8,553	0.0009	0.9991	95.96
45.5	5,029,349		0.0000	1.0000	95.87
46.5	5,260,520	530	0.0001	0.9999	95.87
47.5	5,254,680	109,351	0.0208	0.9792	95.86
48.5	5,419,578	34,150	0.0063	0.9937	93.86
49.5	5,379,474	41,899	0.0078	0.9922	93.27
50.5	5,330,620	10,923	0.0020	0.9980	92.55
51.5	5,151,310	26,194	0.0051	0.9949	92.36
52.5	5,057,986	127,637	0.0252	0.9748	91.89
53.5	4,927,600	3,485	0.0007	0.9993	89.57
54.5	3,014,647	63,419	0.0210	0.9790	89.51
55.5	3,555,458	185	0.0001	0.9999	87.62
56.5	3,040,640	94,142	0.0310	0.9690	87.62
57.5	2,942,091	306	0.0001	0.9999	84.91
58.5	2,925,460		0.0000	1.0000	84.90
59.5	3,067,535	11,578	0.0038	0.9962	84.90
60.5	2,473,101		0.0000	1.0000	84.58
61.5	671,690	883	0.0013	0.9987	84.58
62.5	639,898	9,782	0.0153	0.9847	84.46
63.5	439,626		0.0000	1.0000	83.17
64.5	439,626	65,636	0.1493	0.8507	83.17
65.5	153,727	8,820	0.0574	0.9426	70.76
66.5	144,907		0.0000	1.0000	66.70
67.5	144,907		0.0000	1.0000	66.70
68.5	144,907		0.0000	1.0000	66.70
69.5	144,523		0.0000	1.0000	66.70
70.5	144,523		0.0000	1.0000	66.70
71.5	144,523		0.0000	1.0000	66.70
72.5	144,523		0.0000	1.0000	66.70
73.5	144,523		0.0000	1.0000	66.70
74.5	144,523		0.0000	1.0000	66.70
75.5	144,523		0.0000	1.0000	66.70
76.5					66.70

KENTUCKY UTILITIES COMPANY
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	43,050,630	1,108	0.0000	1.0000	100.00
0.5	41,182,460	5,849	0.0001	0.9999	100.00
1.5	40,211,977	3,818	0.0001	0.9999	99.98
2.5	38,718,681	117,883	0.0030	0.9970	99.97
3.5	36,066,852	91,858	0.0025	0.9975	99.67
4.5	34,348,177	58,752	0.0017	0.9983	99.42
5.5	32,796,479	142,990	0.0044	0.9956	99.25
6.5	26,917,416	104,872	0.0039	0.9961	98.81
7.5	25,388,431	128,040	0.0050	0.9950	98.43
8.5	24,934,467	116,507	0.0047	0.9953	97.93
9.5	24,693,591	107,515	0.0044	0.9956	97.47
10.5	24,024,308	44,310	0.0018	0.9982	97.05
11.5	23,641,590	114,108	0.0048	0.9952	96.87
12.5	23,043,472	134,225	0.0058	0.9942	96.40
13.5	22,214,442	197,348	0.0089	0.9911	95.84
14.5	20,576,476	112,147	0.0055	0.9945	94.99
15.5	20,111,394	232,788	0.0116	0.9884	94.47
16.5	19,592,885	48,424	0.0025	0.9975	93.38
17.5	19,371,767	10,956	0.0006	0.9994	93.15
18.5	17,995,734	266,714	0.0148	0.9852	93.10
19.5	17,594,677	169,390	0.0096	0.9904	91.72
20.5	15,905,188	44,000	0.0028	0.9972	90.83
21.5	15,175,280	30,647	0.0020	0.9980	90.58
22.5	14,313,625	103,845	0.0073	0.9927	90.40
23.5	13,684,588	39,193	0.0029	0.9971	89.74
24.5	13,215,175	50,089	0.0038	0.9962	89.49
25.5	12,753,822	48,388	0.0038	0.9962	89.15
26.5	11,972,251	292,258	0.0244	0.9756	88.81
27.5	10,878,268	19,028	0.0017	0.9983	86.64
28.5	10,086,599	25,435	0.0025	0.9975	86.49
29.5	9,605,922	19,156	0.0020	0.9980	86.27
30.5	9,037,831	31,787	0.0035	0.9965	86.10
31.5	8,736,254	3,204	0.0004	0.9996	85.80
32.5	8,588,171	40,979	0.0048	0.9952	85.76
33.5	6,360,976	26,656	0.0042	0.9958	85.35
34.5	6,258,722	59,208	0.0095	0.9905	85.00
35.5	5,925,080	4,866	0.0008	0.9992	84.19
36.5	3,750,341	6,027	0.0016	0.9984	84.12
37.5	3,735,650		0.0000	1.0000	83.99
38.5	3,716,037	112	0.0000	1.0000	83.99

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1926-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,115,040	3,911	0.0013	0.9987	83.99
40.5	2,400,375	8,454	0.0035	0.9965	83.88
41.5	2,243,134	4,684	0.0021	0.9979	83.59
42.5	2,152,483	1,516	0.0007	0.9993	83.41
43.5	1,115,496	3	0.0000	1.0000	83.35
44.5	1,113,361	23,469	0.0211	0.9789	83.35
45.5	1,083,348	1,852	0.0017	0.9983	81.59
46.5	704,258	8,685	0.0123	0.9877	81.46
47.5	692,384	600	0.0009	0.9991	80.45
48.5	629,130		0.0000	1.0000	80.38
49.5	621,643		0.0000	1.0000	80.38
50.5	620,999		0.0000	1.0000	80.38
51.5	606,027	6,885	0.0114	0.9886	80.38
52.5	597,151		0.0000	1.0000	79.47
53.5	592,857		0.0000	1.0000	79.47
54.5	465,373	657	0.0014	0.9986	79.47
55.5	461,815		0.0000	1.0000	79.36
56.5	394,863		0.0000	1.0000	79.36
57.5	394,796	9,195	0.0233	0.9767	79.36
58.5	368,899	47	0.0001	0.9999	77.51
59.5	370,854	54,060	0.1458	0.8542	77.50
60.5	305,062		0.0000	1.0000	66.20
61.5	198,685	1,111	0.0056	0.9944	66.20
62.5	196,652	2,505	0.0127	0.9873	65.83
63.5	184,483	1,443	0.0078	0.9922	64.99
64.5	183,040		0.0000	1.0000	64.48
65.5	133,514	34,060	0.2551	0.7449	64.48
66.5	99,454		0.0000	1.0000	48.03
67.5	57,780		0.0000	1.0000	48.03
68.5	57,780	3,383	0.0585	0.9415	48.03
69.5	54,397		0.0000	1.0000	45.22
70.5	54,397		0.0000	1.0000	45.22
71.5	54,397		0.0000	1.0000	45.22
72.5	54,397		0.0000	1.0000	45.22
73.5	54,397		0.0000	1.0000	45.22
74.5	54,133		0.0000	1.0000	45.22
75.5	54,133		0.0000	1.0000	45.22
76.5					45.22

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	39,478,933	1,108	0.0000	1.0000	100.00
0.5	38,341,313	5,849	0.0002	0.9998	100.00
1.5	37,497,340	2,159	0.0001	0.9999	99.98
2.5	36,190,633	116,722	0.0032	0.9968	99.98
3.5	34,616,059	85,423	0.0025	0.9975	99.65
4.5	32,915,299	58,572	0.0018	0.9982	99.41
5.5	31,401,220	140,917	0.0045	0.9955	99.23
6.5	25,953,453	100,265	0.0039	0.9961	98.79
7.5	24,435,454	127,461	0.0052	0.9948	98.40
8.5	24,061,109	115,968	0.0048	0.9952	97.89
9.5	23,825,436	104,631	0.0044	0.9956	97.42
10.5	23,162,259	43,405	0.0019	0.9981	96.99
11.5	22,792,828	113,113	0.0050	0.9950	96.81
12.5	22,199,524	131,492	0.0059	0.9941	96.33
13.5	21,375,396	194,864	0.0091	0.9909	95.76
14.5	19,807,626	111,353	0.0056	0.9944	94.89
15.5	19,348,864	220,268	0.0114	0.9886	94.35
16.5	18,845,522	47,436	0.0025	0.9975	93.28
17.5	18,633,467	10,428	0.0006	0.9994	93.04
18.5	17,364,443	264,139	0.0152	0.9848	92.99
19.5	16,968,031	167,387	0.0099	0.9901	91.58
20.5	15,284,284	38,417	0.0025	0.9975	90.67
21.5	14,737,305	29,085	0.0020	0.9980	90.45
22.5	13,900,687	103,728	0.0075	0.9925	90.27
23.5	13,298,791	38,998	0.0029	0.9971	89.59
24.5	12,844,704	44,700	0.0035	0.9965	89.33
25.5	12,395,034	46,319	0.0037	0.9963	89.02
26.5	11,641,660	292,258	0.0251	0.9749	88.69
27.5	10,718,459	19,028	0.0018	0.9982	86.46
28.5	9,935,033	25,435	0.0026	0.9974	86.31
29.5	9,489,264	19,146	0.0020	0.9980	86.09
30.5	8,962,034	31,787	0.0035	0.9965	85.91
31.5	8,662,438	3,204	0.0004	0.9996	85.61
32.5	8,514,368	40,979	0.0048	0.9952	85.58
33.5	6,287,268	26,656	0.0042	0.9958	85.16
34.5	6,185,014	59,208	0.0096	0.9904	84.80
35.5	5,851,899	4,779	0.0008	0.9992	83.99
36.5	3,678,447	6,027	0.0016	0.9984	83.92
37.5	3,663,756		0.0000	1.0000	83.78
38.5	3,656,781	13	0.0000	1.0000	83.78

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2017 EXPERIENCE BAND 1978-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,055,883	3,911	0.0013	0.9987	83.78
40.5	2,341,218	8,454	0.0036	0.9964	83.68
41.5	2,183,977	4,684	0.0021	0.9979	83.38
42.5	2,093,326	1,516	0.0007	0.9993	83.20
43.5	1,056,339	3	0.0000	1.0000	83.14
44.5	1,054,204	23,469	0.0223	0.9777	83.14
45.5	1,024,191	1,852	0.0018	0.9982	81.29
46.5	645,101	8,685	0.0135	0.9865	81.14
47.5	633,227	600	0.0009	0.9991	80.05
48.5	569,973		0.0000	1.0000	79.97
49.5	562,486		0.0000	1.0000	79.97
50.5	561,842		0.0000	1.0000	79.97
51.5	606,027	6,885	0.0114	0.9886	79.97
52.5	597,151		0.0000	1.0000	79.06
53.5	592,857		0.0000	1.0000	79.06
54.5	465,373	657	0.0014	0.9986	79.06
55.5	461,815		0.0000	1.0000	78.95
56.5	394,863		0.0000	1.0000	78.95
57.5	394,796	9,195	0.0233	0.9767	78.95
58.5	368,899	47	0.0001	0.9999	77.11
59.5	370,854	54,060	0.1458	0.8542	77.10
60.5	305,062		0.0000	1.0000	65.86
61.5	198,685	1,111	0.0056	0.9944	65.86
62.5	196,652	2,505	0.0127	0.9873	65.49
63.5	184,483	1,443	0.0078	0.9922	64.66
64.5	183,040		0.0000	1.0000	64.15
65.5	133,514	34,060	0.2551	0.7449	64.15
66.5	99,454		0.0000	1.0000	47.79
67.5	57,780		0.0000	1.0000	47.79
68.5	57,780	3,383	0.0585	0.9415	47.79
69.5	54,397		0.0000	1.0000	44.99
70.5	54,397		0.0000	1.0000	44.99
71.5	54,397		0.0000	1.0000	44.99
72.5	54,397		0.0000	1.0000	44.99
73.5	54,397		0.0000	1.0000	44.99
74.5	54,133		0.0000	1.0000	44.99
75.5	54,133		0.0000	1.0000	44.99
76.5					44.99

PART VIII. NET SALVAGE STATISTICS

KENTUCKY UTILITIES COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2017

Account	Terminal Retirements: Retirements ($)	Terminal Retirements: Net Salvage (%)	Terminal Retirements: Net Salvage ($)	Interim Retirements: Retirements ($)	Interim Retirements: Net Salvage (%)	Interim Retirements: Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
STEAM PRODUCTION PLANT									
BROWN GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	79,335,981	(4)	(3,173,439)	1,787,838	(30)	(536,351.33)	(3,709,791)	81,123,818	(6)
312 BOILER PLANT EQUIPMENT	798,082,061	(4)	(31,923,282)	60,509,152	(30)	(18,152,746)	(50,076,028)	858,591,213	(6)
314 TURBOGENERATOR UNITS	65,285,402	(4)	(2,611,416)	5,595,827	(15)	(839,374)	(3,450,790)	70,881,229	(6)
315 ACCESSORY ELECTRIC EQUIPMENT	50,394,581	(4)	(2,015,783)	1,103,159	(15)	(165,474)	(2,181,257)	51,497,740	(6)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	6,447,562	(4)	(257,902)	549,085	(2)	(10,982)	(268,884)	6,996,647	(6)
TOTAL BROWN GENERATING STATION	*999,545,586*		*(39,981,823)*	*69,545,061*		*(19,704,927)*	*(59,686,750)*	*1,069,090,647*	*(6)*
GHENT GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	150,161,513	(6)	(9,009,691)	6,815,435	(30)	(2,044,631)	(11,054,321)	156,976,949	(8)
312 BOILER PLANT EQUIPMENT	2,162,223,148	(6)	(129,733,389)	238,772,492	(30)	(71,631,748)	(201,365,136)	2,400,995,639	(8)
314 TURBOGENERATOR UNITS	142,761,159	(6)	(8,565,670)	33,714,467	(15)	(5,057,170)	(13,622,840)	176,475,626	(8)
315 ACCESSORY ELECTRIC EQUIPMENT	143,095,498	(6)	(8,585,730)	9,568,749	(15)	(1,435,312)	(10,021,042)	152,664,247	(8)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	16,303,530	(6)	(978,212)	2,084,524	(2)	(41,690)	(1,019,902)	18,388,054	(8)
TOTAL GHENT GENERATING STATION	*2,614,544,848*		*(156,872,691)*	*290,955,667*		*(80,210,551)*	*(237,083,242)*	*2,905,500,515*	*(8)*
GREEN RIVER GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	8,423,626	(10)	(842,363)	-	(30)	-	(842,363)	8,423,626	(10)
312 BOILER PLANT EQUIPMENT	470,724	(10)	(47,072)	-	(30)	-	(47,072)	470,724	(10)
314 TURBOGENERATOR UNITS	164,486	(10)	(16,449)	-	(15)	-	(16,449)	164,486	(10)
315 ACCESSORY ELECTRIC EQUIPMENT	646,150	(10)	(64,615)	-	(15)	-	(64,615)	646,150	(10)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	439,237	(10)	(43,924)	-	(2)	-	(43,924)	439,237	(10)
TOTAL GREEN RIVER GENERATING STATION	*10,144,222*		*(1,014,422)*	-		-	*(1,014,422)*	*10,144,222*	*(10)*
PINEVILLE GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	37,240	(10)	(3,724)	-	(30)	-	(3,724)	37,240	(10)
312 BOILER PLANT EQUIPMENT	145,203	(10)	(14,520)	-	(30)	-	(14,520)	145,203	(10)
314 TURBOGENERATOR UNITS	-	(10)	0	-	(15)	-	-	-	(10)
315 ACCESSORY ELECTRIC EQUIPMENT	-	(10)	0	-	(15)	-	-	-	(10)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	-	(10)	0	-	(2)	-	-	-	(10)
TOTAL PINEVILLE GENERATING STATION	*182,442*		*(18,244)*	-		-	*(18,244)*	*182,442*	*(10)*
SYSTEM LAB									
311 STRUCTURES AND IMPROVEMENTS	1,064,516	0	0	52,603	(30)	(15,781)	(15,781)	1,117,119	0
312 BOILER PLANT EQUIPMENT	-	0	0	-	(30)	-	-	-	0
314 TURBOGENERATOR UNITS	-	0	0	-	(15)	-	-	-	0
315 ACCESSORY ELECTRIC EQUIPMENT	-	0	0	-	(15)	-	-	-	0
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,387,675	0	0	301,238	(2)	(6,025)	(6,025)	3,688,913	0
TOTAL SYSTEM LAB	*4,452,191*		-	*353,841*		*(21,806)*	*(21,806)*	*4,806,032*	*0*
TYRONE GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	2,214,639	(10)	(221,464)	-	(30)	-	(221,464)	2,214,639	(10)
312 BOILER PLANT EQUIPMENT	127,100	(10)	(12,710)	-	(30)	-	(12,710)	127,100	(10)
314 TURBOGENERATOR UNITS	-	(10)	0	-	(15)	-	-	-	(10)
315 ACCESSORY ELECTRIC EQUIPMENT	24,267	(10)	(2,427)	-	(15)	-	(2,427)	24,267	(10)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	86,033	(10)	(8,603)	-	(2)	-	(8,603)	86,033	(10)
TOTAL TYRONE GENERATING STATION	*2,452,040*		*(245,204)*	-		-	*(245,204)*	*2,452,040*	*(10)*
TRIMBLE COUNTY									
311 STRUCTURES AND IMPROVEMENTS	88,236,897	(7)	(6,176,583)	13,626,823	(30)	(4,088,047)	(10,264,630)	101,863,720	(13)
312 BOILER PLANT EQUIPMENT	417,299,547	(7)	(29,210,968)	209,920,296	(30)	(62,976,089)	(92,187,057)	627,219,843	(13)
314 TURBOGENERATOR UNITS	53,597,327	(7)	(3,751,813)	36,388,997	(15)	(5,458,350)	(9,210,162)	89,986,324	(13)
315 ACCESSORY ELECTRIC EQUIPMENT	35,302,438	(7)	(2,471,171)	11,732,586	(15)	(1,759,888)	(4,231,059)	47,035,024	(13)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	5,267,283	(7)	(368,710)	1,735,420	(2)	(34,708)	(403,418)	7,002,703	(13)
TOTAL TRIMBLE COUNTY	*599,703,492*		*(41,979,244)*	*273,404,122*		*(74,317,082)*	*(116,296,326)*	*873,107,614*	*(13)*
TOTAL STEAM PRODUCTION PLANT	**4,231,024,821**		**(240,111,629)**	**634,258,691**		**(174,254,365)**	**(414,365,994)**	**4,865,283,512**	

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	6,045		0		0		0
1989	2,547		0		0		0
1990	54,378		0		0		0
1991							
1992							
1993							
1994							
1995	86,278	10,005	12	2,930	3	7,074-	8-
1996	2,936	609	21	3,210	109	2,601	89
1997	103,244	8,046	8		0	8,046-	8-
1998	32,510	16,167	50		0	16,167-	50-
1999	5,858-	1,967-	34		0	1,967	34-
2000	11,626		0		0		0
2001	144,193	33,335	23		0	33,335-	23-
2002	370,024	20,477	6	241,345	65	220,868	60
2003							
2004	228,612	46,180	20		0	46,180-	20-
2005							
2006	137,959	47,675	35		0	47,675-	35-
2007	2,213,101	777,334	35		0	777,334-	35-
2008	89,209	20,700	23		0	20,700-	23-
2009	145,695	45,964	32	87,350	60	41,386	28
2010	88,392	12,254	14		0	12,254-	14-
2011	681,753	435,245	64		0	435,245-	64-
2012	243,522	153,934	63	2,596	1	151,338-	62-
2013	290,864	98,691	34	276	0	98,416-	34-
2014	674,281	1,428,648	212	38,924-	6-	1,467,572-	218-
2015	1,711,254	156,217	9	30,000	2	126,217-	7-
2016	856,221	350,961	41	1,307	0	349,653-	41-
2017	562,235	496,650	88	1,285	0	495,366-	88-
TOTAL	8,731,023	4,157,125	48	331,375	4	3,825,750-	44-

THREE-YEAR MOVING AVERAGES

88-90	20,990		0		0		0
89-91	18,975		0		0		0
90-92	18,126		0		0		0
91-93							
92-94							
93-95	28,759	3,335	12	977	3	2,358-	8-
94-96	29,738	3,538	12	2,047	7	1,491-	5-
95-97	64,153	6,220	10	2,047	3	4,173-	7-

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	46,230	8,274	18	1,070	2	7,204-	16-
97-99	43,299	7,415	17		0	7,415-	17-
98-00	12,759	4,733	37		0	4,733-	37-
99-01	49,987	10,456	21		0	10,456-	21-
00-02	175,281	17,937	10	80,448	46	62,511	36
01-03	171,406	17,937	10	80,448	47	62,511	36
02-04	199,545	22,219	11	80,448	40	58,229	29
03-05	76,204	15,393	20		0	15,393-	20-
04-06	122,191	31,285	26		0	31,285-	26-
05-07	783,687	275,003	35		0	275,003-	35-
06-08	813,423	281,903	35		0	281,903-	35-
07-09	816,002	281,333	34	29,117	4	252,216-	31-
08-10	107,766	26,306	24	29,117	27	2,811	3
09-11	305,280	164,488	54	29,117	10	135,371-	44-
10-12	337,889	200,478	59	865	0	199,613-	59-
11-13	405,380	229,290	57	957	0	228,333-	56-
12-14	402,889	560,424	139	12,018-	3-	572,442-	142-
13-15	892,133	561,185	63	2,883-	0	564,068-	63-
14-16	1,080,585	645,275	60	2,539-	0	647,814-	60-
15-17	1,043,236	334,609	32	10,864	1	323,745-	31-
FIVE-YEAR AVERAGE							
13-17	818,971	506,233	62	1,211-	0	507,445-	62-

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	5,472,744	33,162-	1-	85,506	2	118,668	2
1989	140,477		0		0		0
1990	139,953		0		0		0
1991							
1992	3,381,168	126,229	4	2,358	0	123,871-	4-
1993	73,171	586,475	802	202,990-	277-	789,466-	
1994	3,105,560	1,235,481	40	5,496	0	1,229,984-	40-
1995	2,831,089	887,355	31	88,317	3	799,038-	28-
1996	2,448,557	1,372,067	56	1,245,733	51	126,335-	5-
1997	3,497,148	736,637	21	6,713	0	729,924-	21-
1998	614,620	826,172	134	14,906-	2-	841,078-	137-
1999	855,983	776,825	91	5,197	1	771,628-	90-
2000	4,074,449		0	20,250	0	20,250	0
2001	2,773,207	973,763	35	350	0	973,413-	35-
2002	1,580,022	47,752	3	842,803	53	795,051	50
2003	3,081,492	1,016,856	33		0	1,016,856-	33-
2004	2,629,000	1,220,722	46		0	1,220,722-	46-
2005	2,723,301	1,455,836	53	3,066	0	1,452,769-	53-
2006	8,467,051	5,300,625	63	17,365	0	5,283,260-	62-
2007	5,552,705	1,817,773	33	176,926	3	1,640,847-	30-
2008	1,602,275	654,037	41		0	654,037-	41-
2009	4,750,276	2,120,465	45	20,000	0	2,100,465-	44-
2010	8,267,108	974,238	12	10,802	0	963,435-	12-
2011	7,436,356	1,421,560	19	342,587	5	1,078,973-	15-
2012	23,431,274	5,029,476	21	172,783	1	4,856,693-	21-
2013	5,299,416	4,590,997	87	323,182	6	4,267,815-	81-
2014	12,989,896	2,451,690	19	186,603	1	2,265,087-	17-
2015	18,285,838	1,902,123	10	260,531	1	1,641,592-	9-
2016	10,706,444	3,910,726	37	199,327	2	3,711,400-	35-
2017	8,820,017	5,529,286	63	131,933	1	5,397,354-	61-
TOTAL	155,030,596	46,932,006	30	3,929,933	3	43,002,073-	28-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
88-90	1,917,725	11,054-	1-	28,502	1	39,556	2
89-91	93,477		0		0		0
90-92	1,173,707	42,076	4	786	0	41,290-	4-
91-93	1,151,446	237,568	21	66,877-	6-	304,446-	26-
92-94	2,186,633	649,395	30	65,045-	3-	714,440-	33-
93-95	2,003,273	903,104	45	36,392-	2-	939,496-	47-
94-96	2,795,069	1,164,968	42	446,515	16	718,452-	26-
95-97	2,925,598	998,687	34	446,921	15	551,766-	19-

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	2,186,775	978,292	45	412,513	19	565,779-	26-
97-99	1,655,917	779,878	47	999-	0	780,877-	47-
98-00	1,848,351	534,332	29	3,514	0	530,819-	29-
99-01	2,567,880	583,529	23	8,599	0	574,930-	22-
00-02	2,809,226	340,505	12	287,801	10	52,704-	2-
01-03	2,478,240	679,457	27	281,051	11	398,406-	16-
02-04	2,430,171	761,777	31	280,934	12	480,842-	20-
03-05	2,811,264	1,231,138	44	1,022	0	1,230,116-	44-
04-06	4,606,451	2,659,061	58	6,811	0	2,652,250-	58-
05-07	5,581,019	2,858,078	51	65,786	1	2,792,292-	50-
06-08	5,207,344	2,590,812	50	64,764	1	2,526,048-	49-
07-09	3,968,419	1,530,758	39	65,642	2	1,465,117-	37-
08-10	4,873,220	1,249,580	26	10,267	0	1,239,312-	25-
09-11	6,817,913	1,505,421	22	124,463	2	1,380,958-	20-
10-12	13,044,913	2,475,091	19	175,391	1	2,299,700-	18-
11-13	12,055,682	3,680,678	31	279,518	2	3,401,160-	28-
12-14	13,906,862	4,024,055	29	227,523	2	3,796,532-	27-
13-15	12,191,717	2,981,604	24	256,772	2	2,724,832-	22-
14-16	13,994,059	2,754,847	20	215,487	2	2,539,360-	18-
15-17	12,604,100	3,780,712	30	197,263	2	3,583,449-	28-
FIVE-YEAR AVERAGE							
13-17	11,220,322	3,676,965	33	220,315	2	3,456,650-	31-

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1994	1,285,265	314,381	24		0	314,381-	24-
1995	1,942,977	374,438	19	110,477	6	263,960-	14-
1996	1,313,231	452,454	34	2,403,674	183	1,951,220	149
1997	3,603,445	466,687	13		0	466,687-	13-
1998	210,345	173,846	83		0	173,846-	83-
1999	152,655	85,180	56		0	85,180-	56-
2000	32,604		0		0		0
2001	100,327	27,123	27		0	27,123-	27-
2002	405,528	42,556	10	314,790	78	272,234	67
2003	3,275,422	878,306	27	61,336	2	816,969-	25-
2004	1,624,795	449,310	28		0	449,310-	28-
2005	771,200	302,941	39		0	302,941-	39-
2006	3,934,128	1,012,073	26		0	1,012,073-	26-
2007	832,436	139,427	17	582,620	70	443,192	53
2008	3,477,445	544,686	16		0	544,686-	16-
2009	4,484,265	1,068,154	24	167,816	4	900,337-	20-
2010	133,532	18,175	14		0	18,175-	14-
2011	1,816,683	534,507	29	920,288	51	385,780	21
2012	957,971	536,939	56		0	536,939-	56-
2013	3,284,484	330,529	10		0	330,529-	10-
2014	1,010,285	223,264	22		0	223,264-	22-
2015	4,274,069	850,763	20		0	850,763-	20-
2016	513,878	481,408	94		0	481,408-	94-
2017	4,382,123	490,378	11	48,995	1	441,383-	10-
TOTAL	43,819,093	9,797,523	22	4,609,996	11	5,187,526-	12-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
94-96	1,513,824	380,424	25	838,051	55	457,626	30
95-97	2,286,551	431,193	19	838,051	37	406,858	18
96-98	1,709,007	364,329	21	801,225	47	436,896	26
97-99	1,322,148	241,904	18		0	241,904-	18-
98-00	131,868	86,342	65		0	86,342-	65-
99-01	95,195	37,434	39		0	37,434-	39-
00-02	179,486	23,226	13	104,930	58	81,704	46
01-03	1,260,426	315,995	25	125,376	10	190,619-	15-
02-04	1,768,582	456,724	26	125,376	7	331,348-	19-
03-05	1,890,472	543,519	29	20,446	1	523,073-	28-
04-06	2,110,041	588,108	28		0	588,108-	28-
05-07	1,845,921	484,814	26	194,207	11	290,607-	16-
06-08	2,748,003	565,395	21	194,207	7	371,189-	14-
07-09	2,931,382	584,089	20	250,145	9	333,944-	11-

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
08-10	2,698,414	543,672	20	55,939	2	487,733-	18-
09-11	2,144,827	540,279	25	362,701	17	177,578-	8-
10-12	969,395	363,207	37	306,762	32	56,445-	6-
11-13	2,019,713	467,325	23	306,762	15	160,563-	8-
12-14	1,750,913	363,577	21		0	363,577-	21-
13-15	2,856,280	468,185	16		0	468,185-	16-
14-16	1,932,744	518,478	27		0	518,478-	27-
15-17	3,056,690	607,516	20	16,332	1	591,184-	19-
FIVE-YEAR AVERAGE							
13-17	2,692,968	475,268	18	9,799	0	465,469-	17-

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1991	6,329		0		0		0
1992							
1993	37,232	74,358	200	396,748-		471,106-	
1994	9,852	977	10		0	977-	10-
1995	145,075	11,330	8	7,322	5	4,008-	3-
1996	76,925	10,741	14	124,975	162	114,234	149
1997	38,297	2,010	5		0	2,010-	5-
1998							
1999							
2000							
2001	16,118	6,569	41		0	6,569-	41-
2002	434		0	64,999		64,999	
2003	836		0		0		0
2004	28,226	7,603	27		0	7,603-	27-
2005							
2006	108,356	11,238	10		0	11,238-	10-
2007	195,095	71,257	37		0	71,257-	37-
2008	975		0		0		0
2009	69,407	58,030	84		0	58,030-	84-
2010	33,428	2,689	8	9,196	28	6,507	19
2011	909,711	308,869	34	119,912	13	188,957-	21-
2012	151,980	93,390	61	618	0	92,772-	61-
2013	363,097	239,415	66	2,808	1	236,607-	65-
2014	50,933	3,296	6	2,842	6	454-	1-
2015	30,263	7,973	26		0	7,973-	26-
2016	248,392	40,448	16		0	40,448-	16-
2017	115,065	15,658	14		0	15,658-	14-
TOTAL	2,636,025	965,851	37	64,076-	2-	1,029,928-	39-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
91-93	14,520	24,786	171	132,249-	911-	157,035-	
92-94	15,695	25,112	160	132,249-	843-	157,361-	
93-95	64,053	28,888	45	129,809-	203-	158,697-	248-
94-96	77,284	7,682	10	44,099	57	36,416	47
95-97	86,766	8,027	9	44,099	51	36,072	42
96-98	38,407	4,250	11	41,658	108	37,408	97
97-99	12,766	670	5		0	670-	5-
98-00							
99-01	5,373	2,190	41		0	2,190-	41-
00-02	5,517	2,190	40	21,666	393	19,477	353
01-03	5,796	2,190	38	21,666	374	19,477	336

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
02-04	9,832	2,534	26	21,666	220	19,132	195
03-05	9,687	2,534	26		0	2,534-	26-
04-06	45,527	6,280	14		0	6,280-	14-
05-07	101,150	27,498	27		0	27,498-	27-
06-08	101,475	27,498	27		0	27,498-	27-
07-09	88,492	43,096	49		0	43,096-	49-
08-10	34,603	20,240	58	3,065	9	17,174-	50-
09-11	337,515	123,196	37	43,036	13	80,160-	24-
10-12	365,039	134,983	37	43,242	12	91,741-	25-
11-13	474,929	213,891	45	41,113	9	172,779-	36-
12-14	188,670	112,034	59	2,089	1	109,944-	58-
13-15	148,098	83,562	56	1,883	1	81,678-	55-
14-16	109,862	17,239	16	947	1	16,292-	15-
15-17	131,240	21,360	16		0	21,360-	16-
FIVE-YEAR AVERAGE							
13-17	161,550	61,358	38	1,130	1	60,228-	37-

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	7,815		0	100	1	100	1
1989	20,616		0	4,480	22	4,480	22
1990	4,249,398		0	164,118	4	164,118	4
1991	4,929		0		0		0
1992	55,521	958	2		0	958-	2-
1993	11,206	383	3	37,633	336	37,251	332
1994	24,722	42	0	337	1	295	1
1995	52,493	70	0	6,472	12	6,402	12
1996	50,369	120	0	7,529	15	7,409	15
1997	244,396	219	0	3,617	1	3,397	1
1998	65,320	374	1	12,212-	19-	12,586-	19-
1999	111,838	432	0	5,234	5	4,802	4
2000	472		0		0		0
2001	25,187		0		0		0
2002	56,542-		0	23,399	41-	23,399	41-
2003							
2004	186,564	10,310	6		0	10,310-	6-
2005							
2006	122,613	3,804	3	567	0	3,237-	3-
2007	196,052	737	0		0	737-	0
2008	15,404		0		0		0
2009	39,354	1,153	3		0	1,153-	3-
2010	20,830	3,603	17		0	3,603-	17-
2011	365,962	8,495	2		0	8,495-	2-
2012	149,327	7,193	5		0	7,193-	5-
2013	10,638	4,091	38		0	4,091-	38-
2014	191,506		0		0		0
2015	81,385	261,730	322		0	261,730-	322-
2016	470,726	10,352	2		0	10,352-	2-
2017	375,840	22,778	6	27,560	7	4,782	1
TOTAL	7,093,940	336,845	5	268,834	4	68,011-	1-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
88-90	1,425,943		0	56,233	4	56,233	4
89-91	1,424,981		0	56,199	4	56,199	4
90-92	1,436,616	319	0	54,706	4	54,387	4
91-93	23,885	447	2	12,544	53	12,098	51
92-94	30,483	461	2	12,657	42	12,196	40
93-95	29,474	165	1	14,814	50	14,649	50
94-96	42,528	77	0	4,779	11	4,702	11
95-97	115,753	137	0	5,872	5	5,736	5

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98	120,028	238	0	356-	0	593-	0
97-99	140,518	342	0	1,121-	1-	1,462-	1-
98-00	59,210	269	0	2,326-	4-	2,595-	4-
99-01	45,832	144	0	1,745	4	1,601	3
00-02	10,294-		0	7,800	76-	7,800	76-
01-03	10,452-		0	7,800	75-	7,800	75-
02-04	43,341	3,437	8	7,800	18	4,363	10
03-05	62,188	3,437	6		0	3,437-	6-
04-06	103,059	4,705	5	189	0	4,516-	4-
05-07	106,222	1,514	1	189	0	1,325-	1-
06-08	111,356	1,514	1	189	0	1,325-	1-
07-09	83,603	630	1		0	630-	1-
08-10	25,196	1,585	6		0	1,585-	6-
09-11	142,049	4,417	3		0	4,417-	3-
10-12	178,706	6,430	4		0	6,430-	4-
11-13	175,309	6,593	4		0	6,593-	4-
12-14	117,157	3,762	3		0	3,762-	3-
13-15	94,509	88,607	94		0	88,607-	94-
14-16	247,872	90,694	37		0	90,694-	37-
15-17	309,317	98,287	32	9,187	3	89,100-	29-
FIVE-YEAR AVERAGE							
13-17	226,019	59,790	26	5,512	2	54,278-	24-

PART IX. DETAILED DEPRECIATION CALCULATIONS

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	34,837,229.35	14,383,181	17,854,686	21,511,383	45.30	474,865
1997	449,904.13	152,019	188,710	319,682	45.97	6,954
2002	24,848.68	6,832	8,481	19,598	46.37	423
2003	61,493.38	16,069	19,947	49,540	46.44	1,067
2008	53,301.70	9,900	12,289	47,941	46.77	1,025
2011	58,056,256.74	7,772,711	9,648,722	55,954,848	46.95	1,191,797
2012	377,820.80	43,560	54,074	372,864	47.00	7,933
2013	79,448.45	7,645	9,490	80,287	47.05	1,706
2014	158,517.38	12,057	14,967	164,158	47.11	3,485
2015	163,213.72	9,037	11,218	173,213	47.16	3,673
2016	855,810.63	29,205	36,254	930,812	47.20	19,721
2017	1,189,423.20	13,790	17,118	1,326,930	47.25	28,083
	96,307,268.16	22,456,006	27,875,957	80,951,256		1,740,732
TRIMBLE COUNTY UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	5,493,644.11	2,268,150	3,219,207	2,988,611	45.30	65,974
2012	62,807.35	7,241	10,277	60,695	47.00	1,291
	5,556,451.46	2,275,391	3,229,484	3,049,306		67,265
SYSTEM LABORATORY						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2040						
NET SALVAGE PERCENT.. 0						
1989	724,776.82	403,382	589,890	134,887	21.99	6,134
1990	58,100.00	31,838	46,559	11,541	22.00	525
1994	6,176.00	3,143	4,596	1,580	22.07	72
1997	16,663.00	7,916	11,576	5,087	22.11	230
2011	19,253.00	4,298	6,285	12,968	22.27	582
2012	255,306.75	49,956	73,054	182,253	22.28	8,180

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SYSTEM LABORATORY						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2040						
NET SALVAGE PERCENT.. 0						
2014	8,935.37	1,197	1,750	7,185	22.30	322
2015	13,745.45	1,371	2,005	11,741	22.30	527
2017	14,162.74	304	445	13,718	22.32	615
	1,117,119.13	503,405	736,160	380,959		17,187
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1956	2,426,213.14	2,522,150	2,571,786			
1958	382.11	397	405			
1965	283.00	293	300			
1979	14,516.00	14,925	15,387			
1982	91,160.00	93,496	96,630			
1983	1,965.00	2,014	2,083			
1984	5,212.00	5,335	5,525			
1985	1,849.00	1,891	1,960			
1987	43,137.68	44,014	45,726			
1988	45,243.11	46,105	47,958			
1989	64,194.00	65,331	68,046			
1990	658.09	669	698			
1991	23,174.40	23,515	24,565			
1994	666,989.00	673,178	707,008			
1995	352,899.61	355,426	374,074			
1996	94,854.89	95,316	100,546			
1997	72,522.04	72,690	76,873			
1998	11,065.00	11,060	11,729			
2004	108,817.17	106,102	115,346			
2005	71,616.67	69,387	75,914			
2006	35,830.85	34,460	37,981			
2007	85,296.44	81,319	90,414			
2008	436,431.15	411,697	462,617			
2014	8,914.20	7,077	8,993	456	1.17	390
2015	13,918.24	10,037	12,754	1,999	1.17	1,709
	4,677,142.79	4,747,884	4,955,316	2,455		2,099

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1963	1,268,530.68	1,315,679	1,344,643			
1965	11,653.00	12,077	12,352			
1966	10,986.00	11,381	11,645			
1967	2,142.72	2,219	2,271			
1979	24,545.95	25,237	26,019			
1980	400.00	411	424			
1983	1,964.15	2,013	2,082			
1992	96,409.90	97,665	102,194			
1997	19,477.46	19,523	20,646			
2004	43,200.52	42,123	45,793			
2005	5,793.58	5,613	6,141			
2007	565,018.59	538,668	598,920			
2009	21,690.24	20,201	22,992			
2012	133,555.40	116,661	141,569			
2015	91,828.24	66,222	84,186	13,152	1.17	11,241
2016	12,530.96	7,440	9,458	3,825	1.17	3,269
	2,309,727.39	2,283,133	2,431,335	16,976		14,510
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1967	1,440.97	1,129	1,300	227	16.88	13
1968	93.83	73	84	15	16.90	1
1971	7,455,327.76	5,715,511	6,583,108	1,319,539	16.96	77,803
1972	56,652.66	43,172	49,725	10,326	16.98	608
1973	11,995.55	9,086	10,465	2,250	16.99	132
1974	2,999.00	2,257	2,600	579	17.01	34
1975	15,098.31	11,286	12,999	3,005	17.03	176
1977	1,211,596.00	892,827	1,028,355	255,936	17.06	15,002
1979	8,850.03	6,421	7,396	1,985	17.09	116
1980	275,262.00	198,097	228,168	63,610	17.10	3,720
1983	3,928.40	2,751	3,169	996	17.14	58
1984	146,459.90	101,557	116,973	38,274	17.15	2,232
1985	37,553.55	25,772	29,684	10,123	17.16	590
1986	44,536.07	30,229	34,818	12,391	17.17	722
1987	251,180.26	168,476	194,050	72,201	17.19	4,200
1988	56,900.74	37,703	43,426	16,889	17.20	982

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1989	477,066.00	312,031	359,396	146,294	17.21	8,501
1990	19,516.88	12,591	14,502	6,186	17.22	359
1991	68,381.00	43,480	50,080	22,404	17.23	1,300
1992	756,531.00	473,688	545,592	256,330	17.24	14,868
1993	84,689.00	52,157	60,074	29,696	17.25	1,722
1995	22,964.00	13,643	15,714	8,628	17.26	500
1997	196,910.73	112,184	129,213	79,512	17.28	4,601
1998	127,955.64	71,207	82,016	53,617	17.29	3,101
2001	83,885.45	43,000	49,527	39,391	17.31	2,276
2003	193,441.22	92,561	106,611	98,436	17.33	5,680
2004	122,280.23	56,258	64,798	64,819	17.33	3,740
2005	95,151.19	41,875	48,231	52,629	17.34	3,035
2007	8,016,945.98	3,175,264	3,657,259	4,840,703	17.35	279,003
2009	200,931.69	69,398	79,932	133,055	17.36	7,664
2010	423,902.15	134,239	154,616	294,720	17.37	16,967
2011	43,327.16	12,394	14,275	31,651	17.37	1,822
2012	602,913.83	152,135	175,229	463,860	17.38	26,689
2013	504,143.53	108,936	125,472	408,920	17.38	23,528
2014	966,396.11	169,996	195,801	828,579	17.39	47,647
2015	57,124.43	7,531	8,674	51,878	17.39	2,983
2016	3,484,095.76	291,463	335,706	3,357,435	17.39	193,067
2017	2,625,976.32	76,241	87,814	2,695,721	17.40	154,926
	28,754,404.33	12,768,619	14,706,856	15,772,813		910,368
BROWN UNITS 1, 2 AND 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
2013	45,235,689.37	9,774,573	12,240,569	35,709,262	17.38	2,054,618
2015	146,854.51	19,360	24,244	131,422	17.39	7,557
	45,382,543.88	9,793,933	12,264,813	35,840,684		2,062,175

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 105-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -8						
1997	8,362,584.36	4,984,716	7,487,753	1,543,838	16.31	94,656
2007	34,607.76	14,486	21,760	15,616	16.37	954
	8,397,192.12	4,999,202	7,509,513	1,559,454		95,610
GHENT UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 105-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -8						
1974	14,424,151.94	11,243,950	14,576,346	1,001,738	16.07	62,336
1979	287,003.73	216,033	280,059	29,905	16.14	1,853
1980	27,171.00	20,290	26,303	3,041	16.15	188
1981	10,791.00	7,992	10,361	1,294	16.16	80
1985	107,260.53	76,532	99,214	16,627	16.20	1,026
1987	218,325.45	152,432	197,609	38,183	16.22	2,354
1988	97,360.62	67,175	87,084	18,066	16.23	1,113
1992	29,300.00	19,139	24,811	6,833	16.27	420
1994	74,968.00	47,379	61,421	19,545	16.29	1,200
1995	60,912.73	37,820	49,029	16,757	16.29	1,029
1996	351,738.57	214,137	277,601	102,276	16.30	6,275
1997	33,704.37	20,090	26,044	10,357	16.31	635
2003	143,388.86	72,171	93,560	61,299	16.35	3,749
2005	240,490.70	111,520	144,571	115,159	16.36	7,039
2007	240,638.23	100,728	130,581	129,308	16.37	7,899
2009	333,988.93	122,179	158,389	202,319	16.38	12,352
2010	643,507.32	216,475	280,632	414,356	16.38	25,296
2011	511,676.99	155,538	201,635	350,976	16.39	21,414
2013	237,388.65	54,719	70,936	185,444	16.40	11,308
2015	1,094,293.61	155,246	201,257	980,580	16.40	59,791
2016	1,515,148.86	135,376	175,498	1,460,863	16.41	89,023
2017	662,038.58	21,143	27,409	687,592	16.41	41,901
	21,345,248.67	13,268,064	17,200,351	5,852,518		358,281

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1977	14,678,326.49	11,215,075	13,481,827	2,370,765	16.11	147,161
1979	227,477.00	171,226	205,834	39,842	16.14	2,469
1980	88,059.38	65,759	79,050	16,054	16.15	994
1981	10,786.00	7,989	9,604	2,045	16.16	127
1986	385,657.47	272,277	327,309	89,201	16.21	5,503
1988	13,292.75	9,171	11,025	3,332	16.23	205
1989	11,294.78	7,696	9,251	2,947	16.24	181
1991	1,929.73	1,280	1,539	545	16.26	34
1995	27,739.56	17,223	20,704	9,255	16.29	568
1998	67,159.90	39,131	47,040	25,493	16.32	1,562
2003	223,834.88	112,661	135,432	106,310	16.35	6,502
2013	194,635.03	44,864	53,932	156,274	16.40	9,529
2015	130,289.29	18,484	22,220	118,493	16.40	7,225
2016	351,144.86	31,374	37,715	341,521	16.41	20,812
2017	241,422.48	7,710	9,268	251,468	16.41	15,324
	16,653,049.60	12,021,920	14,451,749	3,533,545		218,196
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
1981	34,380,542.39	24,098,010	27,869,728	9,261,258	19.01	487,178
1982	1,235,435.00	857,535	991,753	342,517	19.03	17,999
1983	511.16	351	406	146	19.04	8
1987	2,248,542.00	1,475,414	1,706,340	722,086	19.10	37,806
1995	9,779.16	5,636	6,518	4,043	19.20	211
1996	195,780.51	110,454	127,742	83,701	19.21	4,357
2001	263,336.76	129,845	150,168	134,236	19.26	6,970
2002	234,131.24	111,545	129,004	123,858	19.27	6,428
2004	2,640,221.52	1,161,591	1,343,398	1,508,041	19.29	78,177
2005	105,410.84	44,326	51,264	62,580	19.29	3,244
2010	643,443.60	192,381	222,492	472,427	19.33	24,440
2011	109,662.90	29,482	34,096	84,340	19.34	4,361
2014	8,999,804.63	1,474,395	1,705,161	8,014,628	19.35	414,193
2016	64,860.31	5,006	5,790	64,260	19.36	3,319
2017	325,594.72	8,675	10,033	341,610	19.37	17,636
	51,457,056.74	29,704,646	34,353,891	21,219,730		1,106,327

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
1984	15,364,534.75	10,252,914	9,452,560	7,141,138	20.00	357,057
1985	928,979.83	612,744	564,912	438,386	20.02	21,897
1986	734,905.00	478,798	441,422	352,275	20.04	17,579
1987	15,869.00	10,209	9,412	7,726	20.05	385
1988	8,118.00	5,152	4,750	4,018	20.07	200
1989	20,054.00	12,549	11,569	10,089	20.08	502
1990	23,192.76	14,292	13,176	11,872	20.10	591
1991	16,217.00	9,837	9,069	8,445	20.11	420
1992	24,302.00	14,490	13,359	12,887	20.13	640
1993	42,417.00	24,842	22,903	22,908	20.14	1,137
1994	11,881.56	6,827	6,294	6,538	20.15	324
1996	70,941.70	39,062	36,013	40,604	20.18	2,012
1997	1,942,669.00	1,044,866	963,303	1,134,780	20.19	56,205
2001	618,493.64	296,734	273,571	394,403	20.23	19,496
2002	186,501.00	86,387	79,644	121,778	20.24	6,017
2003	86,074.14	38,365	35,370	57,590	20.25	2,844
2004	276,923.25	118,309	109,074	190,003	20.26	9,378
2005	181,861.63	74,100	68,316	128,095	20.27	6,319
2007	7,212,117.43	2,627,726	2,422,603	5,366,484	20.29	264,489
2010	581,597.75	167,578	154,497	473,629	20.31	23,320
2011	437,903.41	113,415	104,562	368,374	20.32	18,129
2012	265,809.06	60,535	55,810	231,264	20.32	11,381
2013	1,076,247.83	208,351	192,087	970,261	20.33	47,726
2014	10,160,659.69	1,591,379	1,467,154	9,506,358	20.34	467,373
2015	462,088.77	54,043	49,824	449,232	20.34	22,086
2016	903,040.74	66,124	60,962	914,322	20.35	44,930
2017	1,617,760.77	41,897	38,626	1,708,555	20.35	83,958
	43,271,160.71	18,071,525	16,660,841	30,072,013		1,486,395
GHENT UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1994	15,816,339.70	9,995,838	14,084,948	2,996,699	16.29	183,959
	15,816,339.70	9,995,838	14,084,948	2,996,699		183,959

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
2017	36,901.04	956		39,853	20.35	1,958
	36,901.04	956		39,853		1,958
	341,081,605.72	142,890,522	170,461,214	201,288,261		8,265,062

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.4 2.42

KENTUCKY UTILITIES COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1947	559,688.83	615,658	615,658			
1948	291,289.73	320,419	320,419			
1949	3,757.35	4,133	4,133			
1951	449.85	495	495			
1953	284,320.41	312,752	312,752			
1954	19,256.64	21,182	21,182			
1955	1,152.61	1,268	1,268			
1966	18.41	20	20			
1970	15,244.21	16,769	16,769			
1973	0.48	1	1			
1978	45,723.00	50,295	50,295			
1987	1.57	2	2			
1989	18,427.65	20,270	20,270			
1994	23,811.21	26,192	26,192			
1995	7,264.00	7,990	7,990			
1996	21.00	23	23			
1998	6,158.71	6,775	6,775			
1999	1,781.97	1,960	1,960			
2000	10,208.60	11,229	11,229			
2003	10,426.12	11,469	11,469			
2004	2,086.10	2,295	2,295			
2007	135,867.17	149,454	149,454			
2009	157,801.67	173,582	173,582			
2011	10,306.64	11,337	11,337			
2013	6,150.84	6,766	6,766			
2015	209,964.73	230,961	230,961			
	1,821,179.50	2,003,297	2,003,297			
TYRONE UNITS 1 AND 2						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1947	464,339.65	510,774	510,774			
1973	32,257.44	35,483	35,483			
1974	3,680.00	4,048	4,048			
2000	36,257.09	39,883	39,883			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNITS 1 AND 2						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
2001	78,101.58	85,912	85,912			
2003	11,541.15	12,695	12,695			
2004	4,683.12	5,151	5,151			
	630,860.03	693,946	693,946			
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	1,550,242.02	1,705,266	1,705,266			
1955	34,484.51	37,933	37,933			
1977	454,212.76	499,634	499,634			
1978	2,303.00	2,533	2,533			
1982	372,934.13	410,228	410,228			
1985	19,443.60	21,388	21,388			
1996	107,389.55	118,129	118,129			
1997	26,427.69	29,070	29,070			
2007	40,561.24	44,617	44,617			
2011	107,003.10	117,703	117,703			
2012	10,061.86	11,068	11,068			
2013	31,239.04	34,363	34,363			
	2,756,302.50	3,031,932	3,031,933			
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	1,164.00	1,280	1,280			
1959	2,161,579.97	2,377,738	2,377,738			
1960	9,468.10	10,415	10,415			
1965	0.10		0			
1966	2,606.00	2,867	2,867			
1971	881.40	970	970			
1972	65.10	72	72			
1974	36.19	40	40			
1975	1,648.52	1,813	1,813			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1980	42,214.04	46,435	46,435			
1981	66.60	73	73			
1982	1,306.83	1,438	1,438			
1984	7,645.65	8,410	8,410			
1985	24,235.92	26,660	26,660			
1986	79,771.36	87,748	87,748			
1987	8,740.03	9,614	9,614			
1988	18,125.00	19,938	19,938			
1989	156.90	173	173			
1990	0.35		0			
1991	152,430.19	167,673	167,673			
1992	2,336.56	2,570	2,570			
1993	4,681.88	5,150	5,150			
1994	0.20		0			
1995	35,470.17	39,017	39,017			
1996	148,489.00	163,338	163,338			
1997	103,109.11	113,420	113,420			
1999	13,769.35	15,146	15,146			
2000	125,696.00	138,266	138,266			
2001	42,304.92	46,535	46,535			
2003	61,159.54	67,275	67,275			
2004	23,213.76	25,535	25,535			
2005	230,880.63	253,969	253,969			
2006	23,820.27	26,202	26,202			
2007	126,896.02	139,586	139,586			
2009	247,241.98	271,966	271,966			
2010	93,859.03	103,245	103,245			
2011	463,969.76	510,367	510,367			
2012	520,231.89	572,255	572,255			
2013	809,993.40	890,993	890,993			
2016	42,182.68	46,401	46,401			
	5,631,448.40	6,194,593	6,194,593			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNITS 1 AND 2						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1941	632.00	695	695			
1950	1,022,178.80	1,124,397	1,124,397			
1951	43,895.11	48,285	48,285			
1954	12,435.28	13,679	13,679			
1960	11,239.00	12,363	12,363			
1961	219.00	241	241			
1965	6,953.70	7,649	7,649			
1970	0.08		0			
1973	5,098.15	5,608	5,608			
1974	32,248.63	35,473	35,473			
1975	427,498.02	470,248	470,248			
1977	91,811.76	100,993	100,993			
1978	34,073.00	37,480	37,480			
1997	68,189.00	75,008	75,008			
	1,756,471.53	1,932,119	1,932,119			
PINEVILLE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1951	5,844.00	6,428	6,428			
1963	7,129.00	7,842	7,842			
1970	1,082.00	1,190	1,190			
1975	8,772.00	9,649	9,649			
1976	20.00	22	22			
1978	2,577.11	2,835	2,835			
1979	8,108.00	8,919	8,919			
1988	1,821.00	2,003	2,003			
1995	31,090.00	34,199	34,199			
1997	6,678.00	7,346	7,346			
2000	10,484.00	11,532	11,532			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PINEVILLE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 105-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
2002	51,958.50	57,154	57,154			
2011	9,638.92	10,603	10,603			
2013	37,239.96	40,964	40,964			
	182,442.49	200,686	200,687			
	12,778,704.45	14,056,573	14,056,575			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	30,411,667.13	12,652,230	17,857,673	16,507,510	38.51	428,655
1999	46,214.59	14,440	20,381	31,842	40.74	782
2002	235,262.87	64,194	90,605	175,242	41.37	4,236
2003	251,881.90	65,234	92,073	192,554	41.57	4,632
2004	103,726.28	25,377	35,818	81,393	41.76	1,949
2008	11,126.98	2,041	2,881	9,693	42.47	228
2011	479,985,991.31	63,350,471	89,414,437	452,969,733	42.95	10,546,443
2012	4,494,781.01	510,856	721,035	4,358,068	43.10	101,115
2013	836,833.81	79,319	111,953	833,669	43.25	19,276
2014	10,993,731.73	825,876	1,165,662	11,257,255	43.39	259,444
2015	5,565,936.43	303,909	428,945	5,860,563	43.53	134,633
2016	8,836,470.17	295,163	416,600	9,568,611	43.67	219,112
2017	12,492,828.31	140,463	198,253	13,918,643	43.80	317,777
	554,266,452.52	78,329,573	110,556,316	515,764,775		12,038,282
TRIMBLE COUNTY UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	11,005,849.25	4,578,787	7,757,291	4,679,319	38.51	121,509
2003	51,829.65	13,423	22,741	35,827	41.57	862
2005	14,655.98	3,374	5,716	10,845	41.94	259
2007	131,148.15	26,142	44,289	103,908	42.30	2,456
2011	60,043,715.62	7,924,810	13,426,057	54,423,341	42.95	1,267,133
2012	1,218,956.00	138,541	234,713	1,142,707	43.10	26,513
2013	131,025.54	12,419	21,040	127,019	43.25	2,937
2014	338,774.33	25,450	43,117	339,698	43.39	7,829
2016	17,436.11	582	986	18,717	43.67	429
	72,953,390.63	12,723,528	21,555,951	60,881,380		1,429,927
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1950	38,574.00	40,067	40,888			
1956	3,863,943.49	4,008,089	4,095,780			

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1957	198,794.49	206,118	210,722			
1959	13,000.91	13,472	13,781			
1965	11,524.63	11,919	12,216			
1966	34.45	36	37			
1968	1,948.40	2,013	2,065			
1973	1,590,515.65	1,639,010	1,685,947			
1974	18,694.00	19,253	19,816			
1975	441,330.00	454,271	467,810			
1977	7,170.50	7,372	7,601			
1978	1,881.00	1,932	1,994			
1983	80,244.00	82,109	85,059			
1984	4,372.00	4,469	4,634			
1985	27,185.00	27,763	28,816			
1987	70,883.58	72,230	75,137			
1988	311,788.04	317,325	330,495			
1989	12,314.44	12,517	13,053			
1990	16,976.00	17,231	17,995			
1991	11,405,119.81	11,558,822	12,089,427			
1992	299,803.87	303,352	317,792			
1994	809,175.97	815,767	857,727			
1995	5,085.27	5,116	5,390			
1996	551,595.25	553,691	584,691			
1997	269,896.00	270,249	286,090			
1999	6,580.00	6,551	6,975			
2001	1,316,699.00	1,301,631	1,395,701			
2002	13,656.00	13,443	14,475			
2003	217,931.20	213,504	231,007			
2004	1,794,079.90	1,748,103	1,901,725			
2005	556,841.17	539,154	590,252			
2006	40,236.58	38,674	42,651			
2007	421,857.31	401,982	447,169			
2008	2,917,291.73	2,751,029	3,092,329			
2009	1,903,167.53	1,772,067	1,996,820	20,538	1.16	17,705
2010	2,427,890.91	2,224,821	2,506,997	66,567	1.16	57,385
2011	180,640.37	162,215	182,789	8,690	1.16	7,491
2012	3,112,190.42	2,719,994	3,064,974	233,948	1.16	201,679
2013	518,642.40	436,285	491,619	58,141	1.16	50,122
2014	64,953.85	51,638	58,187	10,664	1.16	9,193

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
2015	1,920,395.92	1,388,679	1,564,807	470,813	1.16	405,873
2016	629,503.50	376,282	424,006	243,267	1.16	209,713
2017	462,166.89	147,557	166,272	323,625	1.16	278,987
	38,556,575.43	36,737,802	39,433,716	1,436,254		1,238,148
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1963	4,969,891.71	5,143,600	5,268,085			
1964	83,935.36	86,839	88,971			
1965	2,736.70	2,830	2,901			
1966	425.52	440	451			
1975	2,622,355.35	2,699,252	2,779,697			
1976	19,653.62	20,218	20,833			
1977	1,845.00	1,897	1,956			
1978	16,079.65	16,519	17,044			
1980	82,061.00	84,181	86,985			
1985	3,930.00	4,013	4,166			
1988	117,057.24	119,136	124,081			
1989	38,963.27	39,603	41,301			
1990	28,392.45	28,819	30,096			
1991	382,847.00	388,006	405,818			
1992	195,307.00	197,618	207,025			
1993	2,164,127.18	2,185,883	2,293,975			
1994	3,820,792.27	3,851,912	4,050,040			
1995	314,560.32	316,469	333,434			
1998	380.00	379	403			
1999	1,985,695.00	1,976,947	2,104,837			
2002	30,185.00	29,713	31,996			
2003	419,887.86	411,357	445,081			
2004	3,336,963.09	3,251,447	3,537,181			
2005	115,467.62	111,800	122,396			
2007	319,765.64	304,701	338,952			
2008	38,247.48	36,068	40,542			
2009	5,684,731.37	5,293,136	6,025,815			
2010	1,991,547.56	1,824,973	2,111,040			
2011	636,571.01	571,641	674,765			

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
2012	6,650,986.04	5,812,833	6,880,984	169,061	1.16	145,742
2013	595,614.98	501,035	593,104	38,248	1.16	32,972
2014	1,500,354.55	1,192,782	1,411,965	178,411	1.16	153,803
2015	2,829,271.46	2,045,907	2,421,858	577,170	1.16	497,560
2016	838,753.03	501,360	593,489	295,590	1.16	254,819
2017	365,423.23	116,669	138,108	249,241	1.16	214,863
	42,204,805.56	39,169,983	43,229,373	1,507,721		1,299,759
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1971	23,523,835.90	17,761,889	13,144,470	11,790,796	15.69	751,485
1972	227,473.81	170,702	126,326	114,796	15.75	7,289
1973	121,887.17	90,877	67,252	61,948	15.81	3,918
1974	23,028.00	17,059	12,624	11,785	15.86	743
1975	413.00	304	225	213	15.91	13
1976	8,312,827.29	6,073,393	4,494,541	4,317,056	15.96	270,492
1977	300,180.00	217,713	161,116	157,075	16.01	9,811
1980	328,422.00	232,514	172,069	176,058	16.15	10,901
1981	831.05	583	431	449	16.19	28
1982	1,751,913.00	1,218,619	901,824	955,204	16.23	58,854
1983	208,501.00	143,648	106,305	114,706	16.27	7,050
1984	583,948.05	398,267	294,733	324,252	16.31	19,881
1985	178,836.30	120,691	89,316	100,251	16.35	6,132
1986	6,308.00	4,211	3,116	3,570	16.38	218
1987	1,331,048.28	878,095	649,824	761,088	16.42	46,351
1988	825,544.36	538,032	398,164	476,913	16.45	28,992
1990	631,688.53	400,877	296,664	372,926	16.51	22,588
1991	23,220.54	14,524	10,748	13,865	16.54	838
1992	11,745,103.85	7,233,838	5,353,314	7,096,496	16.57	428,274
1993	2,346,857.63	1,421,703	1,052,114	1,435,555	16.60	86,479
1994	3,067,380.50	1,826,357	1,351,573	1,899,850	16.62	114,311
1995	750,300.20	438,387	324,423	470,895	16.65	28,282
1997	4,676,406.78	2,620,513	1,939,279	3,017,712	16.70	180,701
1998	68,370.00	37,441	27,708	44,764	16.72	2,677
1999	401,832.00	214,611	158,820	267,122	16.74	15,957
2000	127,001.94	66,001	48,843	85,779	16.76	5,118

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
2001	251,033.71	126,648	93,724	172,371	16.78	10,272
2002	74,954.25	36,601	27,086	52,365	16.80	3,117
2003	391,655.38	184,545	136,570	278,584	16.82	16,563
2004	86,283.64	39,073	28,915	62,545	16.84	3,714
2005	3,194,942.75	1,384,594	1,024,652	2,361,987	16.86	140,094
2006	3,039,853.38	1,253,679	927,770	2,294,475	16.88	135,929
2007	8,078,544.98	3,152,392	2,332,889	6,230,368	16.89	368,879
2008	1,093,013.42	400,097	296,087	862,507	16.91	51,006
2009	245,739.33	83,589	61,859	198,625	16.93	11,732
2010	1,198,155.42	374,346	277,030	993,015	16.94	58,620
2011	3,445,815.41	970,852	718,467	2,934,097	16.96	173,001
2012	126,893,443.63	31,595,706	23,382,018	111,125,032	16.97	6,548,322
2013	27,923,468.83	5,944,934	4,399,476	25,199,401	16.99	1,483,190
2014	2,079,275.62	361,020	267,168	1,936,864	17.00	113,933
2015	90,311,570.30	11,744,189	8,691,144	87,039,120	17.02	5,113,932
2016	99,107,043.92	8,137,442	6,022,015	99,031,452	17.03	5,815,118
2017	13,673,311.61	397,128	293,890	14,199,821	17.04	833,323
	442,651,264.76	108,327,684	80,166,586	389,043,755		22,988,128
BROWN UNITS 1, 2 AND 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1994	5,159,404.89	3,071,975	3,029,123	2,439,846	16.62	146,802
2010	31,326,108.76	9,787,373	9,650,845	23,554,831	16.94	1,390,486
2012	254,234.17	63,303	62,420	207,068	16.97	12,202
2013	295,455,751.48	62,902,825	62,025,367	251,157,730	16.99	14,782,680
2014	763,791.58	132,616	130,766	678,853	17.00	39,933
2015	578,635.26	75,246	74,196	539,157	17.02	31,678
2016	1,607,398.04	131,980	130,139	1,573,703	17.03	92,408
2017	33,243.04	966	953	34,285	17.04	2,012
	335,178,567.22	76,166,284	75,103,808	280,185,473		16,498,201

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1994	6,386.32	3,973	5,241	1,656	15.73	105
1997	21,423,616.00	12,575,465	16,588,163	6,549,342	15.79	414,778
2010	12,043.79	3,992	5,266	7,741	16.01	484
2011	759,148.82	227,705	300,363	519,517	16.02	32,429
2012	115,917,937.08	30,738,238	40,546,486	84,644,886	16.04	5,277,113
2013	152,123.49	34,589	45,626	118,667	16.05	7,394
2014	67,811.53	12,608	16,631	56,605	16.06	3,525
2015	452,417.04	63,260	83,446	405,165	16.07	25,213
2016	214,603.28	18,917	24,953	206,818	16.09	12,854
2017	570,048.23	17,823	23,510	592,142	16.10	36,779
	139,576,135.58	43,696,570	57,639,685	93,102,541		5,810,674
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1958	50,033.00	41,562	39,426	14,609	14.07	1,038
1974	48,328,296.23	37,094,152	35,187,978	17,006,582	15.05	1,130,005
1979	153,844.00	113,980	108,123	58,029	15.27	3,800
1980	485,218.64	356,612	338,287	185,750	15.31	12,133
1981	6,294.00	4,587	4,351	2,446	15.35	159
1982	40,874.00	29,537	28,019	16,125	15.38	1,048
1983	0.16		0			
1984	705.60	500	474	288	15.45	19
1985	3,913.34	2,748	2,607	1,620	15.48	105
1986	20,989.71	14,577	13,828	8,841	15.52	570
1987	190,485.08	130,824	124,101	81,623	15.55	5,249
1989	84,769.00	56,835	53,914	37,636	15.60	2,413
1990	63,912.00	42,287	40,114	28,911	15.63	1,850
1991	310,440.00	202,523	192,116	143,159	15.66	9,142
1992	354,903.01	228,156	216,432	166,864	15.68	10,642
1993	90,815.89	57,447	54,495	43,586	15.71	2,774
1994	379,207.79	235,902	223,780	185,765	15.73	11,810
1995	8,458,382.43	5,168,248	4,902,665	4,232,388	15.75	268,723
1996	787,729.69	472,080	447,821	402,927	15.77	25,550
1998	134,109.00	76,970	73,015	71,823	15.81	4,543
1999	149,045.50	83,471	79,182	81,788	15.83	5,167
2000	37,620.04	20,518	19,464	21,166	15.85	1,335

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
2001	4,242,188.53	2,247,394	2,131,906	2,449,657	15.87	154,358
2002	3,272,250.00	1,679,477	1,593,173	1,940,857	15.89	122,143
2003	1,517,122.97	752,363	713,701	924,792	15.90	58,163
2004	53,691,449.22	25,618,553	24,302,081	33,684,684	15.92	2,115,872
2005	6,533,312.05	2,985,313	2,831,905	4,224,072	15.94	264,998
2006	2,377,396.83	1,035,483	982,272	1,585,316	15.95	99,393
2007	1,359,443.47	560,456	531,656	936,543	15.97	58,644
2008	993,616.17	385,256	365,459	707,647	15.98	44,283
2009	3,419,068.72	1,232,920	1,169,563	2,523,031	16.00	157,689
2010	4,060,588.58	1,346,022	1,276,853	3,108,582	16.01	194,165
2011	4,926,814.09	1,477,790	1,401,850	3,919,109	16.02	244,639
2012	28,796,494.21	7,636,035	7,243,639	23,856,575	16.04	1,487,318
2013	1,552,115.87	352,908	334,773	1,341,512	16.05	83,583
2014	2,380,884.08	442,684	419,936	2,151,419	16.06	133,961
2015	166,530,486.47	23,285,558	22,088,972	157,763,953	16.07	9,817,296
2016	5,112,103.09	450,630	427,473	5,093,598	16.09	316,569
2017	5,034,197.76	157,399	149,311	5,287,623	16.10	328,424
	355,931,120.22	116,079,757	110,114,714	274,290,896		17,179,573
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1977	58,175,364.71	43,749,364	36,857,216	25,972,178	15.19	1,709,821
1978	378,364.00	282,472	237,972	170,661	15.23	11,206
1979	171,073.08	126,745	106,778	77,981	15.27	5,107
1980	41,332.94	30,378	25,592	19,047	15.31	1,244
1981	6,265.64	4,567	3,848	2,919	15.35	190
1982	74,950.00	54,161	45,629	35,317	15.38	2,296
1986	622,685.40	432,451	364,324	308,176	15.52	19,857
1987	303,212.93	208,245	175,439	152,031	15.55	9,777
1988	440,286.00	298,824	251,748	223,761	15.58	14,362
1989	22,395.85	15,016	12,650	11,537	15.60	740
1990	3,078.00	2,037	1,716	1,608	15.63	103
1991	159,055.00	103,763	87,416	84,363	15.66	5,387
1994	554,181.74	344,751	290,440	308,076	15.73	19,585
1995	192,226.00	117,454	98,951	108,653	15.75	6,899
1996	1,317,733.68	789,707	665,299	757,854	15.77	48,057

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1997	1,696,598.00	995,887	838,998	993,328	15.79	62,909
1998	31,096.00	17,847	15,035	18,548	15.81	1,173
1999	1,037,479.70	581,024	489,491	630,987	15.83	39,860
2000	18,464.61	10,071	8,484	11,457	15.85	723
2001	406,215.00	215,201	181,299	257,413	15.87	16,220
2002	5,138,574.32	2,637,365	2,221,882	3,327,778	15.89	209,426
2003	281,262.34	139,482	117,508	186,255	15.90	11,714
2005	2,911,587.84	1,330,413	1,120,824	2,023,691	15.94	126,957
2006	388,451.69	169,191	142,537	276,991	15.95	17,366
2007	384,330.33	158,447	133,486	281,591	15.97	17,632
2008	179,568.29	69,624	58,656	135,278	15.98	8,465
2009	209,912.20	75,695	63,770	162,935	16.00	10,183
2010	5,115,447.96	1,695,691	1,428,557	4,096,127	16.01	255,848
2011	696,400.85	208,884	175,977	576,136	16.02	35,964
2012	30,284,534.59	8,030,623	6,765,502	25,941,795	16.04	1,617,319
2013	22,866,954.02	5,199,314	4,380,229	20,316,081	16.05	1,265,799
2014	1,722,539.16	320,277	269,821	1,590,521	16.06	99,036
2015	139,129,149.04	19,454,095	16,389,353	133,870,128	16.07	8,330,437
2016	1,134,039.40	99,965	84,217	1,140,546	16.09	70,885
2017	1,093,971.20	34,204	28,816	1,152,673	16.10	71,595
	277,188,781.51	88,003,235	74,139,461	225,224,423		14,124,142
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
1981	128,887,548.59	88,829,556	94,419,316	44,779,236	17.85	2,508,641
1982	4,323,370.79	2,950,540	3,136,208	1,533,032	17.90	85,644
1983	175,918.00	118,824	126,301	63,690	17.95	3,548
1984	9,724,031.69	6,497,769	6,906,653	3,595,301	18.00	199,739
1985	13,041.58	8,618	9,160	4,925	18.04	273
1986	5,003.81	3,267	3,473	1,932	18.09	107
1987	773,529.19	498,833	530,223	305,189	18.13	16,833
1989	51,742.00	32,478	34,522	21,360	18.21	1,173
1990	148,350.00	91,757	97,531	62,687	18.25	3,435
1994	124,286.66	71,816	76,335	57,894	18.39	3,148
1995	694,601.50	393,284	418,032	332,138	18.43	18,022
1996	328,272.00	181,943	193,392	161,142	18.46	8,729

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
1997	1,620,817.00	878,077	933,332	817,151	18.49	44,194
1998	206,918.25	109,365	116,247	107,225	18.52	5,790
1999	5,607,517.20	2,887,012	3,068,682	2,987,436	18.54	161,135
2000	72,921.99	36,475	38,770	39,985	18.57	2,153
2002	602,894.00	282,393	300,163	350,962	18.62	18,849
2003	855,281.04	385,692	409,962	513,741	18.65	27,546
2004	70,682,706.81	30,583,785	32,508,325	43,828,998	18.67	2,347,563
2005	3,708,105.24	1,532,860	1,629,318	2,375,436	18.69	127,097
2006	1,083,127.40	425,343	452,108	717,669	18.71	38,358
2007	170,859.09	63,278	67,260	117,268	18.74	6,258
2008	7,849.41	2,721	2,892	5,585	18.76	298
2009	5,797,862.51	1,862,352	1,979,544	4,282,148	18.78	228,016
2010	3,722,211.44	1,094,080	1,162,927	2,857,061	18.80	151,971
2011	2,923,273.40	773,782	822,474	2,334,662	18.82	124,052
2012	5,638,318.74	1,315,733	1,398,528	4,690,856	18.83	249,116
2013	5,171,161.32	1,027,501	1,092,158	4,492,696	18.85	238,339
2014	170,490,781.71	27,477,727	29,206,813	154,923,232	18.87	8,210,028
2015	3,549,687.32	427,377	454,270	3,379,392	18.89	178,898
2016	2,668,331.09	201,294	213,961	2,667,837	18.91	141,081
2017	3,657,764.25	97,733	103,883	3,846,502	18.92	203,303
	433,488,085.02	171,143,265	181,912,764	286,254,368		15,353,337
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
1984	123,326,066.27	80,882,266	67,698,210	65,493,942	18.82	3,480,018
1986	209,125.43	133,871	112,050	113,806	18.93	6,012
1987	110,311.00	69,725	58,360	60,776	18.97	3,204
1989	864,078.80	530,938	444,393	488,812	19.07	25,633
1990	160,162.29	96,951	81,148	91,828	19.11	4,805
1991	11,877.00	7,076	5,923	6,905	19.15	361
1992	91,017.00	53,310	44,620	53,678	19.19	2,797
1994	36,963.56	20,856	17,456	22,464	19.27	1,166
1995	1,910,485.07	1,056,442	884,239	1,179,085	19.30	61,092
1996	704,727.26	381,139	319,012	442,093	19.34	22,859
1998	7,924.00	4,083	3,417	5,140	19.40	265
1999	1,429,371.01	716,750	599,918	943,803	19.43	48,575

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
2000	42,052.00	20,471	17,134	28,282	19.46	1,453
2001	373,444.57	176,065	147,366	255,954	19.49	13,133
2002	813,279.13	370,186	309,845	568,497	19.52	29,124
2003	2,723,839.24	1,192,613	998,213	1,943,533	19.55	99,413
2004	53,538,230.21	22,482,073	18,817,427	39,003,862	19.57	1,993,044
2005	4,262,301.29	1,706,852	1,428,630	3,174,655	19.60	161,972
2006	12,983.46	4,936	4,131	9,891	19.62	504
2007	728,088.85	260,773	218,266	568,070	19.65	28,909
2008	247,594.72	82,978	69,452	197,950	19.67	10,064
2009	8,610,056.79	2,672,214	2,236,635	7,062,226	19.69	358,671
2010	3,558,896.46	1,007,986	843,681	2,999,927	19.72	152,126
2011	6,272,978.31	1,597,299	1,336,934	5,437,882	19.74	275,475
2012	50,601,919.19	11,333,332	9,485,964	45,164,108	19.76	2,285,633
2013	11,920,334.08	2,272,512	1,902,086	10,971,875	19.78	554,695
2014	456,159,644.01	70,380,324	58,908,117	433,744,299	19.80	21,906,278
2015	1,868,343.42	214,695	179,699	1,838,112	19.82	92,740
2016	12,762,644.96	920,610	770,548	13,013,109	19.84	655,903
2017	7,837,630.42	195,702	163,802	8,300,839	19.86	417,968
	751,196,369.80	200,845,028	168,106,676	643,185,403		32,693,892
GHENT UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1994	55,574,813.33	34,572,580	57,134,124	2,886,674	15.73	183,514
2001	57,800.67	30,621	50,604	11,821	15.87	745
2002	373,088.95	191,487	316,449	86,488	15.89	5,443
2003	244,482.98	121,243	200,364	63,677	15.90	4,005
2004	463,143.19	220,986	365,198	134,997	15.92	8,480
2006	13,411.72	5,842	9,654	4,830	15.95	303
2012	8,780,826.10	2,328,433	3,847,933	5,635,359	16.04	351,332
2013	297,276.90	67,593	111,703	209,356	16.05	13,044
2015	580,743.20	81,204	134,197	493,006	16.07	30,679
2016	41,434.95	3,652	6,035	38,715	16.09	2,406
2017	3,698,546.13	115,639	191,103	3,803,327	16.10	236,231
	70,125,568.12	37,739,280	62,367,365	13,368,249		836,182

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
2007	109,685,027.52	40,622,245	37,585,192	80,874,638	18.74	4,315,616
2011	6,848,600.71	1,812,805	1,677,274	5,719,215	18.82	303,890
2012	249,577.51	58,240	53,886	215,658	18.83	11,453
2013	222,658.95	44,242	40,934	199,537	18.85	10,586
2014	567,246.36	91,422	84,587	528,039	18.87	27,983
2015	221,002.85	26,608	24,619	214,064	18.89	11,332
2016	437,494.93	33,004	30,537	441,958	18.91	23,372
2017	1,096,322.41	29,293	27,103	1,156,925	18.92	61,148
	119,327,931.24	42,717,859	39,524,131	89,350,035		4,765,380
GHENT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
2011	125,544.16	31,968	53,807	81,781	19.74	4,143
2012	251,732,171.56	56,380,555	94,897,318	176,973,428	19.76	8,956,145
2013	865,241.71	164,951	277,638	656,823	19.78	33,206
2014	435,675.38	67,220	113,142	357,388	19.80	18,050
2015	75,609.90	8,688	14,623	67,035	19.82	3,382
2016	153,720.92	11,088	18,663	147,356	19.84	7,427
2017	773,684.26	19,319	32,517	803,062	19.86	40,436
	254,161,647.89	56,683,789	95,407,708	179,086,872		9,062,789
	3,886,806,695.50	1,108,363,637	1,159,258,254	3,052,682,145		155,318,414

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.7 4.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 312.1 BOILER PLANT EQUIPMENT - ASH PONDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2023						
NET SALVAGE PERCENT.. 0						
1990	4,493,379.64	3,688,615	3,041,332	1,452,048	6.00	242,008
2011	4,610,665.23	2,397,546	1,976,821	2,633,844	6.00	438,974
	9,104,044.87	6,086,161	5,018,153	4,085,892		680,982
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2019						
NET SALVAGE PERCENT.. 0						
2005	170,126.36	146,661	170,126			
2007	172,621.19	145,002	172,621			
2008	8,648.65	7,145	8,649			
2009	224,059.52	181,381	224,060			
	575,455.72	480,189	575,456			
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2019						
NET SALVAGE PERCENT.. 0						
1978	931,932.13	887,022	931,932			
1985	296.57	279	297			
1997	5,030.40	4,583	5,030			
2004	49,756.95	43,337	49,757			
2005	26,461.24	22,811	26,461			
2007	72,732.11	61,095	72,732			
2009	246,680.85	199,693	246,681			
2010	130,846.99	103,300	130,847			
2011	334,280.60	255,628	334,281			
2012	33,823.14	24,804	33,823			
	1,831,840.98	1,602,552	1,831,841			

KENTUCKY UTILITIES COMPANY

ACCOUNT 312.1 BOILER PLANT EQUIPMENT - ASH PONDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PINEVILLE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2019						
NET SALVAGE PERCENT.. 0						
1977	50,117.00	47,758	50,117			
1978	41,148.89	39,166	41,149			
	91,265.89	86,924	91,266			
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2020						
NET SALVAGE PERCENT.. 0						
1993	9,299,115.00	8,284,675	9,298,845	270	3.00	90
	9,299,115.00	8,284,675	9,298,845	270		90
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2020						
NET SALVAGE PERCENT.. 0						
1993	3,909,061.67	3,482,622	2,991,413	917,649	3.00	305,883
	3,909,061.67	3,482,622	2,991,413	917,649		305,883
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S4						
PROBABLE RETIREMENT YEAR.. 12-2020						
NET SALVAGE PERCENT.. 0						
2008	19,802,080.26	15,049,581	5,142,558	14,659,522	3.00	4,886,507
	19,802,080.26	15,049,581	5,142,558	14,659,522		4,886,507

KENTUCKY UTILITIES COMPANY

ACCOUNT 312.1 BOILER PLANT EQUIPMENT - ASH PONDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2020 NET SALVAGE PERCENT.. 0						
1997	39,480.55	34,440	39,209	272	3.00	91
	39,480.55	34,440	39,209	272		91
GHENT UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2022 NET SALVAGE PERCENT.. 0						
1974	1,777,792.39	1,594,520	1,766,490	11,303	5.00	2,261
1987	322,828.55	277,358	307,271	15,557	5.00	3,111
	2,100,620.94	1,871,878	2,073,761	26,860		5,372
GHENT UNIT 4 INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2021 NET SALVAGE PERCENT.. 0						
1994	16,544,368.68	14,137,990	7,607,181	8,937,188	4.00	2,234,297
2004	16,148,295.19	12,457,279	6,702,846	9,445,449	4.00	2,361,362
	32,692,663.87	26,595,269	14,310,027	18,382,637		4,595,659
GHENT UNIT 2 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2020 NET SALVAGE PERCENT.. 0						
1994	1,901,133.18	1,685,906	1,901,133			
	1,901,133.18	1,685,906	1,901,133			
	81,346,762.93	65,260,197	43,273,662	38,073,102		10,474,584

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.6 12.88

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	10,495,573.59	4,820,496	6,572,140	5,287,858	34.07	155,206
2008	10,044,788.71	1,960,024	2,672,246	8,678,365	41.30	210,130
2011	63,452,777.33	8,865,908	12,087,550	59,614,088	42.17	1,413,661
2012	35,891.34	4,312	5,879	34,678	42.45	817
2014	2,395,609.34	189,303	258,091	2,448,948	42.96	57,005
2015	581,903.51	33,515	45,693	611,857	43.20	14,163
2016	2,364,803.69	82,866	112,977	2,559,251	43.44	58,915
2017	614,976.53	7,401	10,090	684,833	43.66	15,686
	89,986,324.04	15,963,825	21,764,667	79,919,879		1,925,583
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1956	3,209,637.23	3,328,217	3,402,215			
1959	14,882.13	15,418	15,775			
1968	5,774.91	5,966	6,121			
1985	11,462.31	11,709	12,150			
1996	32,671.87	32,810	34,632			
1997	17,942.90	17,974	19,019			
2001	103,385.99	102,250	109,589			
2004	163,261.40	159,155	173,057			
2009	467,034.49	435,110	495,057			
2010	0.03		0			
2012	1,851,245.33	1,616,029	1,962,320			
2013	77,712.20	65,286	82,375			
2014	262,052.93	207,885	277,776			
2015	5,133,151.02	3,701,771	5,120,672	320,468	1.17	273,904
2016	10,064.58	5,976	8,267	2,402	1.17	2,053
2017	20,639.88	6,458	8,933	12,945	1.17	11,064
	11,380,919.20	9,712,014	11,727,960	335,814		287,021

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1963	4,017,807.85	4,157,984	4,258,876			
1965	26,462.00	27,368	28,050			
1985	8,768.76	8,957	9,295			
1990	23,666.17	24,030	25,086			
1994	1,497,407.00	1,510,206	1,587,251			
1995	574,163.49	577,891	608,613			
1996	32,822.53	32,961	34,792			
1997	33,091.00	33,149	35,076			
2002	1,508,264.00	1,485,472	1,598,760			
2003	362,121.20	354,952	383,848			
2004	1,221,923.10	1,191,192	1,295,238			
2005	146,394.62	141,825	155,178			
2006	632,295.16	608,082	670,233			
2007	2,547.40	2,429	2,700			
2009	927,175.48	863,798	982,806			
2010	840,714.12	769,915	891,157			
2011	13,859.99	12,433	14,529	163	1.17	139
2012	364,931.03	318,564	372,266	14,561	1.17	12,445
2013	35,612.96	29,919	34,963	2,787	1.17	2,382
2014	1,106,284.24	877,608	1,025,550	147,111	1.17	125,736
2015	275,708.32	198,827	232,344	59,907	1.17	51,203
2017	51,040.14	15,970	18,662	35,440	1.17	30,291
	13,703,060.56	13,243,532	14,265,275	259,969		222,196
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1971	6,622,731.15	5,098,695	2,236,353	4,783,742	14.52	329,459
1973	2,376.00	1,805	792	1,727	14.76	117
1984	13,467.21	9,317	4,087	10,189	15.81	644
1993	6,448.62	3,956	1,735	5,100	16.38	311
1994	191,259.00	115,263	50,556	152,179	16.43	9,262
1995	421,519.00	249,293	109,343	337,467	16.48	20,477
1997	10,429,790.49	5,915,508	2,594,618	8,460,960	16.57	510,619
1998	297,088.00	164,605	72,198	242,715	16.61	14,613
1999	68,653.00	37,093	16,269	56,503	16.65	3,394
2003	61,008.77	29,060	12,746	51,923	16.80	3,091

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
2004	72,895.42	33,379	14,640	62,629	16.83	3,721
2005	4,204,448.97	1,840,668	807,341	3,649,375	16.87	216,323
2006	562,067.65	234,253	102,746	493,045	16.90	29,174
2008	781,074.49	289,017	126,767	701,172	16.95	41,367
2009	810,823.83	278,736	122,257	737,216	16.98	43,417
2011	407,184.46	116,010	50,883	380,732	17.03	22,357
2012	16,784,850.43	4,225,230	1,853,240	15,938,701	17.05	934,821
2013	60,585.16	13,012	5,707	58,513	17.08	3,426
2014	1,314,686.65	229,994	100,878	1,292,690	17.10	75,596
2015	1,346,993.07	176,835	77,562	1,350,251	17.12	78,870
2017	1,337,298.12	38,571	16,918	1,400,618	17.16	81,621
	45,797,249.49	19,100,300	8,377,637	40,167,447		2,422,680
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1974	13,697,463.09	10,679,698	11,629,895	3,163,366	14.19	222,929
1975	38,921.00	30,136	32,817	9,217	14.29	645
1976	156.00	120	131	38	14.38	3
1979	21,978.00	16,510	17,979	5,757	14.65	393
1980	3,163.50	2,357	2,567	850	14.73	58
1985	156,856.25	111,516	121,438	47,967	15.08	3,181
1989	252,974.07	171,621	186,891	86,321	15.32	5,635
1992	58,228.11	37,865	41,234	21,652	15.47	1,400
1994	1,803,234.05	1,134,648	1,235,600	711,893	15.56	45,751
1995	13,200.94	8,157	8,883	5,374	15.60	344
1996	32,637.46	19,771	21,530	13,718	15.65	877
2001	424,030.20	227,007	247,204	210,748	15.83	13,313
2002	162,462.00	84,250	91,746	83,713	15.86	5,278
2003	1,089,602.19	545,692	594,243	582,527	15.89	36,660
2004	1,385,035.03	667,248	726,615	769,223	15.92	48,318
2006	1,501,464.76	660,665	719,446	902,136	15.97	56,489
2008	11,574,683.26	4,531,614	4,934,802	7,565,856	16.02	472,276
2009	426,823.12	155,370	169,194	291,775	16.05	18,179
2011	3,073,590.83	930,815	1,013,632	2,305,846	16.09	143,309
2012	58,830.81	15,751	17,152	46,385	16.11	2,879
2013	355,249.66	81,491	88,741	294,928	16.13	18,284

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
2014	23,384.79	4,382	4,772	20,484	16.15	1,268
2015	2,428,504.79	341,434	371,812	2,250,973	16.17	139,207
2016	787,747.30	70,418	76,683	774,084	16.18	47,842
2017	957,520.21	30,362	33,063	1,001,058	16.20	61,794
	40,327,741.42	20,558,898	22,388,069	21,165,892		1,346,312
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1977	17,316,453.74	13,217,102	14,172,164	4,529,606	14.47	313,034
1978	4,313,274.00	3,266,751	3,502,805	1,155,531	14.56	79,363
1979	20,087.00	15,089	16,179	5,515	14.65	376
1980	2,264.00	1,687	1,809	636	14.73	43
1981	899.00	664	712	259	14.80	18
1985	128,384.83	91,274	97,869	40,786	15.08	2,705
1993	11,440.84	7,320	7,849	4,507	15.52	290
1996	2,506,918.63	1,518,594	1,628,327	1,079,145	15.65	68,955
1997	29,881.11	17,731	19,012	13,259	15.68	846
1998	64,136.87	37,204	39,892	29,375	15.72	1,869
1999	678,802.78	384,155	411,914	321,193	15.76	20,380
2002	137,999.16	71,564	76,735	72,304	15.86	4,559
2004	951,927.36	458,596	491,734	536,348	15.92	33,690
2005	458,645.99	211,653	226,947	268,391	15.95	16,827
2006	172,946.00	76,099	81,598	105,184	15.97	6,586
2009	2,195,130.77	799,058	856,798	1,513,944	16.05	94,327
2011	241,196.39	73,045	78,323	182,169	16.09	11,322
2012	902,565.37	241,646	259,107	715,663	16.11	44,424
2013	1,341,650.30	307,764	330,003	1,118,979	16.13	69,373
2014	115,704.20	21,679	23,246	101,715	16.15	6,298
2015	249,264.64	35,045	37,577	231,628	16.17	14,325
2016	348,992.43	31,197	33,451	343,461	16.18	21,228
2017	868,410.34	27,536	29,526	908,357	16.20	56,071
	33,056,975.75	20,912,453	22,423,578	13,277,956		866,909

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
1981	23,715,442.13	16,658,229	19,422,957	6,189,720	17.04	363,246
1982	480,015.00	333,653	389,029	129,388	17.15	7,544
1983	29,912.17	20,573	23,987	8,318	17.25	482
1984	7,192,035.00	4,890,897	5,702,628	2,064,770	17.35	119,007
1985	156,856.24	105,443	122,943	46,462	17.44	2,664
1987	44,239.03	28,999	33,812	13,966	17.62	793
1995	2,196,292.70	1,262,258	1,471,752	900,244	18.19	49,491
1996	2,264.00	1,273	1,484	961	18.25	53
1999	60,118.00	31,389	36,599	28,329	18.41	1,539
2003	555,078.69	253,738	295,850	303,635	18.60	16,324
2004	943,602.66	413,934	482,634	536,457	18.64	28,780
2005	619,008.50	259,216	302,237	366,292	18.68	19,609
2006	365,407.85	145,311	169,428	225,213	18.72	12,031
2007	1,228,187.47	460,607	537,053	789,390	18.76	42,078
2009	1,824,052.27	593,554	692,065	1,277,912	18.83	67,866
2011	1,402,218.14	376,040	438,451	1,075,945	18.89	56,958
2012	1,314,528.73	310,202	361,686	1,058,006	18.92	55,920
2013	530,602.17	106,788	124,511	448,539	18.95	23,670
2014	152,425.65	24,884	29,014	135,606	18.98	7,145
2016	457,129.60	34,954	40,755	452,945	19.03	23,802
2017	589,956.17	15,648	18,245	618,908	19.06	32,472
	43,859,372.17	26,327,590	30,697,120	16,671,002		931,474
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
1984	41,011,924.40	27,424,379	28,940,984	15,351,894	18.09	848,640
1985	236,810.00	156,402	165,051	90,704	18.20	4,984
1986	51,406.00	33,523	35,377	20,142	18.30	1,101
1987	65,193.00	41,963	44,284	26,125	18.39	1,421
1989	118,897.45	74,375	78,488	49,921	18.57	2,688
1991	21,490.58	13,021	13,741	9,469	18.74	505
1993	194,113.31	113,521	119,799	89,844	18.89	4,756
1994	321,113.00	184,207	194,394	152,408	18.96	8,038
1996	33,858.00	18,603	19,632	16,935	19.10	887
2000	676.00	334	352	378	19.34	20
2003	3,702,461.38	1,644,888	1,735,853	2,262,806	19.49	116,101

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R2						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
2004	106,038.93	45,134	47,630	66,892	19.54	3,423
2005	951,102.73	386,460	407,832	619,359	19.58	31,632
2006	1,053,339.88	405,671	428,105	709,502	19.63	36,144
2007	391,047.02	141,966	149,817	272,514	19.67	13,854
2008	399,683.45	135,627	143,127	288,531	19.71	14,639
2009	1,462,218.47	459,293	484,693	1,094,503	19.75	55,418
2011	9,957.80	2,569	2,711	8,043	19.82	406
2012	3,951,908.24	896,762	946,354	3,321,707	19.85	167,340
2013	766,472.18	148,050	156,237	671,553	19.88	33,780
2014	2,164,941.54	338,328	357,038	1,981,099	19.92	99,453
2015	25,437.69	2,973	3,137	24,335	19.94	1,220
2016	146,534.85	10,712	11,304	146,953	19.97	7,359
2017	2,044,910.82	51,767	54,630	2,153,874	20.00	107,694
	59,231,536.72	32,730,528	34,540,570	29,429,490		1,561,503
	337,343,179.35	158,549,140	166,184,876	201,227,449		9,563,678

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.0 2.83

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	9,229,511.61	4,221,487	4,594,015	5,835,334	39.94	146,103
2008	28,344.56	5,425	5,904	26,126	46.49	562
2011	34,193,435.89	4,695,361	5,109,706	33,528,877	46.99	713,532
2012	1,088,194.59	128,266	139,585	1,090,075	47.14	23,124
2013	159,449.60	15,630	17,009	163,169	47.27	3,452
2014	447,854.18	34,808	37,880	468,196	47.39	9,880
2015	228,635.93	12,918	14,058	244,301	47.50	5,143
2016	190,160.29	6,565	7,144	207,737	47.60	4,364
2017	53,968.16	632	688	60,296	47.70	1,264
	45,619,554.81	9,121,092	9,925,988	41,624,109		907,424
TRIMBLE COUNTY UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
1990	1,415,469.10	647,422	793,978	805,502	39.94	20,168
	1,415,469.10	647,422	793,978	805,502		20,168
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1956	965,068.08	1,003,219	1,022,972			
1958	96,451.16	100,214	102,238			
1963	780.00	809	827			
1965	63,901.00	66,234	67,735			
1968	2,135.00	2,210	2,263			
1979	58,759.52	60,451	62,285			
1989	1,850.00	1,883	1,961			
1992	1,344.04	1,362	1,425			
1995	1,428,056.08	1,438,824	1,513,739			
2001	68,330.19	67,632	72,430			
2006	767,016.47	737,897	813,037			
2009	166,049.72	154,717	176,013			
2010	19,084.61	17,500	20,230			
2011	53,830.80	48,357	57,061			

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
2014	79,740.42	63,348	84,525			
2015	433,058.83	312,700	447,066	11,977	1.17	10,237
2016	48,892.14	29,116	41,627	10,199	1.17	8,717
2017	66,975.99	21,256	30,390	40,605	1.17	34,705
	4,321,324.05	4,127,729	4,517,823	62,780		53,659
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1948	384.00	400	407			
1963	817,849.45	848,316	866,920			
1965	1,103.00	1,143	1,169			
1966	397.00	411	421			
1970	793.56	821	841			
1984	38,251.57	39,173	40,547			
1994	185,597.00	187,392	196,733			
1995	12,605.00	12,700	13,361			
1997	36,014.00	36,112	38,175			
1998	10,424.35	10,424	11,050			
2005	30,977.05	30,023	32,836			
2010	105,240.55	96,501	111,555			
2011	34,981.18	31,424	36,519	561	1.17	479
2012	1,109,729.78	969,976	1,127,258	49,055	1.17	41,927
2014	20,568.37	16,340	18,990	2,813	1.17	2,404
2016	11,513.95	6,857	7,969	4,236	1.17	3,621
	2,416,429.81	2,288,013	2,504,751	56,665		48,431
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1972	4,207,199.70	3,277,071	3,726,557	733,074	15.86	46,222
1973	69,444.66	53,701	61,067	12,545	15.98	785
1974	17,025.00	13,072	14,865	3,182	16.08	198
1984	4,045.00	2,839	3,228	1,059	16.89	63

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 70-R4 PROBABLE RETIREMENT YEAR.. 6-2035 NET SALVAGE PERCENT.. -6						
1985	798.00	554	630	216	16.94	13
1988	8,408.74	5,629	6,401	2,512	17.08	147
1989	8,164.40	5,393	6,133	2,522	17.12	147
1990	9,591.76	6,246	7,103	3,065	17.16	179
1991	5,344.58	3,428	3,898	1,767	17.20	103
1997	778,846.00	446,538	507,786	317,791	17.35	18,316
2003	45,349.90	21,814	24,806	23,265	17.43	1,335
2004	18,213.04	8,417	9,571	9,734	17.44	558
2005	6,057.20	2,677	3,044	3,376	17.45	193
2007	1,652,556.67	657,434	747,608	1,004,102	17.46	57,509
2010	208,220.77	66,294	75,387	145,327	17.47	8,319
2011	163,301.43	46,868	53,296	119,803	17.48	6,854
2012	1,510,611.21	383,243	435,809	1,165,439	17.48	66,673
2013	14,410.13	3,127	3,556	11,719	17.48	670
2014	100,296.43	17,728	20,160	86,155	17.49	4,926
2015	131,881.19	17,483	19,881	119,913	17.49	6,856
2016	6,475,762.92	542,212	616,582	6,247,726	17.49	357,217
	15,435,528.73	5,581,768	6,347,369	10,014,291		577,283
BROWN UNITS 1, 2 AND 3 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 70-R4 PROBABLE RETIREMENT YEAR.. 6-2035 NET SALVAGE PERCENT.. -6						
2013	29,308,888.08	6,360,433	6,736,338	24,331,083	17.48	1,391,938
2017	15,569.02	459	486	16,017	17.49	916
	29,324,457.10	6,360,892	6,736,824	24,347,101		1,392,854

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1997	2,978,785.13	1,786,771	2,416,350	800,738	16.37	48,915
2011	5,833.85	1,782	2,410	3,891	16.48	236
2012	9,121,453.85	2,465,058	3,333,636	6,517,535	16.48	395,481
2016	117,306.68	10,564	14,286	112,405	16.49	6,817
	12,223,379.51	4,264,175	5,766,682	7,434,568		451,449
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1974	6,348,415.72	5,037,384	6,126,347	729,942	15.27	47,802
1978	869,693.72	669,398	814,106	125,163	15.61	8,018
1994	911,155.00	579,830	705,176	278,872	16.32	17,088
1995	70.00	44	54	22	16.34	1
1996	15,852.00	9,713	11,813	5,307	16.35	325
2000	14,398.00	8,018	9,751	5,799	16.41	353
2004	33,927.95	16,503	20,071	16,572	16.45	1,007
2005	160,601.93	74,799	90,969	82,481	16.46	5,011
2007	53,989.17	22,687	27,591	30,717	16.47	1,865
2009	84,877.13	31,168	37,906	53,762	16.48	3,262
2011	268,831.65	82,122	99,875	190,463	16.48	11,557
2012	178,069.98	48,123	58,526	133,790	16.48	8,118
2013	43,107.20	9,981	12,139	34,417	16.49	2,087
2014	33,762.45	6,384	7,764	28,699	16.49	1,740
2015	3,068,772.44	436,324	530,647	2,783,627	16.49	168,807
2016	127,767.94	11,506	13,993	123,996	16.49	7,519
2017	123,589.14	3,928	4,777	128,699	16.49	7,805
	12,336,881.42	7,047,912	8,571,504	4,752,328		292,365
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1977	9,794,204.35	7,599,684	8,911,497	1,666,243	15.53	107,292
1984	2,100,053.81	1,530,372	1,794,536	473,522	15.97	29,651
1989	42,801.92	29,415	34,492	11,734	16.18	725

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1996	44,978.99	27,560	32,317	16,260	16.35	994
1997	152,868.92	91,696	107,524	57,574	16.37	3,517
2007	95,312.10	40,052	46,966	55,972	16.47	3,398
2009	292,925.23	107,565	126,132	190,227	16.48	11,543
2010	60,449.95	20,400	23,921	41,365	16.48	2,510
2011	1,111,858.00	339,648	398,276	802,531	16.48	48,697
2012	34,908.72	9,434	11,062	26,639	16.48	1,616
2013	66,340.84	15,361	18,013	53,636	16.49	3,253
2014	81,708.97	15,451	18,118	70,128	16.49	4,253
2015	335,328.94	47,678	55,908	306,247	16.49	18,572
	14,213,740.74	9,874,316	11,578,763	3,772,077		236,021
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
1976	639,635.42	478,694	560,026	130,780	17.91	7,302
1981	25,047,721.92	17,875,116	20,912,172	6,139,368	18.43	333,118
1982	687,842.97	485,666	568,183	174,688	18.52	9,432
1984	95,821.00	66,138	77,375	26,112	18.68	1,398
1987	68,793.51	45,728	53,497	20,800	18.88	1,102
1988	18,279.36	11,984	14,020	5,722	18.94	302
2000	4,283,840.81	2,195,158	2,568,124	2,058,424	19.35	106,379
2007	51,757.15	19,591	22,920	32,978	19.44	1,696
2012	72,766.46	17,310	20,251	58,337	19.47	2,996
2013	10,609.78	2,146	2,511	8,948	19.48	459
2014	2,536,658.89	417,267	488,162	2,251,429	19.48	115,576
2015	32,239.52	3,960	4,633	30,186	19.48	1,550
2016	18,243.03	1,408	1,647	18,055	19.49	926
	33,564,209.82	21,620,166	25,293,521	10,955,826		582,236

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
1984	21,499,657.05	14,590,054	13,868,375	9,351,255	19.56	478,081
1985	48,287.00	32,362	30,761	21,389	19.64	1,089
1988	20,564.21	13,231	12,577	9,633	19.85	485
1991	5,683.09	3,487	3,315	2,823	20.02	141
1993	155,202.00	91,853	87,310	80,309	20.11	3,993
1994	24,278.82	14,089	13,392	12,829	20.15	637
2000	2,476,120.09	1,235,565	1,174,449	1,499,760	20.33	73,771
2003	42,697.44	19,155	18,208	27,906	20.38	1,369
2011	27,699.80	7,213	6,856	23,060	20.46	1,127
2013	13,232.05	2,575	2,448	11,843	20.47	579
2014	23,100,966.21	3,632,581	3,452,900	21,496,144	20.48	1,049,616
2015	212,920.54	25,017	23,780	206,175	20.48	10,067
2016	230,240.27	16,969	16,130	232,530	20.48	11,354
2017	4,327,248.64	111,321	105,815	4,567,614	20.49	222,919
	52,184,797.21	19,795,472	18,816,313	37,543,268		1,855,228
GHENT UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
2011	5,833.85	1,782	1,863	4,438	16.48	269
2012	890,617.40	240,688	251,596	710,271	16.48	43,099
2013	54,747.62	12,676	13,250	45,877	16.49	2,782
	951,198.87	255,146	266,709	760,586		46,150
GHENT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
2007	11,277,366.96	4,268,691	4,228,585	7,950,972	19.44	409,001
2011	764,631.32	206,450	204,510	621,292	19.47	31,910
	12,041,998.28	4,475,141	4,433,095	8,572,263		440,911

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R4						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
2011	5,833.83	1,519	1,528	4,773	20.46	233
2012	15,142,207.72	3,458,456	3,478,820	12,874,764	20.47	628,958
	15,148,041.55	3,459,975	3,480,348	12,879,537		629,191
	251,197,011.00	98,919,219	109,033,668	163,580,901		7,533,370

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.7   3.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -13						
2000	41,467.41	12,325	15,767	31,091	41.89	742
2002	26,900.64	7,289	9,325	21,073	42.23	499
2011	4,522,589.85	594,354	760,346	4,350,181	43.54	99,912
2012	203,432.33	23,020	29,449	200,429	43.67	4,590
2013	838,229.79	79,101	101,192	846,007	43.79	19,320
2014	831,413.70	62,138	79,492	860,006	43.91	19,586
2015	130,793.56	7,125	9,115	138,682	44.03	3,150
2016	125,813.18	4,188	5,358	136,811	44.14	3,099
2017	282,062.33	3,210	4,106	314,624	44.25	7,110
	7,002,702.79	792,750	1,014,150	6,898,904		158,008
SYSTEM LABORATORY						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2040						
NET SALVAGE PERCENT.. 0						
1983	229.68	136	126	103	20.68	5
1984	10,283.72	6,021	5,597	4,686	20.73	226
1986	48,397.00	27,624	25,680	22,717	20.83	1,091
1987	100,806.00	56,754	52,760	48,046	20.88	2,301
1989	3,576.00	1,955	1,817	1,759	20.97	84
1990	22,201.79	11,945	11,104	11,098	21.01	528
1991	72,843.39	38,540	35,827	37,016	21.05	1,758
1994	4,476.87	2,237	2,080	2,397	21.17	113
1995	3,198.74	1,565	1,455	1,744	21.20	82
1996	5,552.69	2,654	2,467	3,085	21.24	145
1997	47,150.16	21,996	20,448	26,702	21.27	1,255
1998	67,015.37	30,435	28,293	38,722	21.31	1,817
1999	62,975.53	27,795	25,839	37,137	21.34	1,740
2000	730.00	312	290	440	21.37	21
2002	276,203.04	110,296	102,533	173,670	21.42	8,108
2003	632,334.03	242,576	225,503	406,831	21.45	18,966
2004	199,225.39	73,140	67,992	131,233	21.48	6,110
2005	131,911.92	46,111	42,866	89,046	21.51	4,140
2006	31,404.52	10,400	9,668	21,736	21.53	1,010
2007	89,149.53	27,761	25,807	63,342	21.56	2,938
2009	226,404.22	60,855	56,572	169,832	21.60	7,863
2010	90,044.40	22,039	20,488	69,557	21.63	3,216
2011	250,794.23	55,059	51,184	199,610	21.65	9,220

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SYSTEM LABORATORY						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2040						
NET SALVAGE PERCENT.. 0						
2012	175,216.25	33,750	31,375	143,842	21.67	6,638
2013	161,221.62	26,363	24,508	136,714	21.69	6,303
2014	325,883.54	43,000	39,974	285,910	21.71	13,170
2015	38,318.47	3,768	3,503	34,816	21.73	1,602
2016	152,643.59	9,356	8,697	143,946	21.75	6,618
2017	458,721.29	9,895	9,199	449,523	21.77	20,649
	3,688,912.98	1,004,338	933,650	2,755,263		127,717
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1954	7,308.72	7,587	7,747			
1955	921.00	956	976			
1956	96,637.48	100,262	102,436			
1971	671.82	693	712			
1988	1,387.17	1,412	1,470			
1990	18,405.00	18,685	19,509			
1992	7,705.00	7,797	8,167			
1994	9,227.37	9,304	9,781			
1995	1,940.96	1,953	2,057			
1996	2,858.88	2,870	3,030			
2001	64,870.51	64,136	68,763			
2003	118,172.07	115,790	125,262			
2005	13,393.06	12,969	14,197			
2007	497.91	474	528			
2011	8,037.82	7,218	8,073	447	1.16	385
2014	37,649.44	29,931	33,475	6,433	1.16	5,546
	389,684.21	382,037	406,185	6,880		5,931
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1963	59,546.28	61,648	63,119			
1965	541.89	561	574			

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 2-2019						
NET SALVAGE PERCENT.. -6						
1968	520.36	538	552			
1969	4,400.82	4,545	4,665			
1970	555.08	573	588			
1995	3,998.73	4,024	4,239			
1996	2,858.69	2,870	3,030			
1998	5,685.52	5,678	6,027			
2000	3,709.49	3,681	3,932			
2007	21,010.50	20,023	22,271			
2012	20,279.74	17,724	21,417	80	1.16	69
	123,107.10	121,865	130,414	80		69
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1969	55,586.77	42,450	46,375	12,547	15.89	790
1970	2,634.00	2,000	2,185	607	15.94	38
1971	373,932.83	282,274	308,376	87,993	15.99	5,503
1972	6,479.06	4,862	5,312	1,556	16.03	97
1973	960.00	716	782	235	16.08	15
1974	3,179.00	2,355	2,573	797	16.12	49
1976	2,020.00	1,476	1,612	529	16.20	33
1977	39,153.91	28,403	31,029	10,474	16.24	645
1978	1,537.00	1,106	1,208	421	16.28	26
1980	769.95	545	595	221	16.35	14
1981	7,296.00	5,123	5,597	2,137	16.38	130
1982	1.31	1	1			
1983	52,115.16	35,916	39,237	16,005	16.45	973
1984	7,364.85	5,026	5,491	2,316	16.48	141
1985	14,815.00	10,003	10,928	4,776	16.51	289
1986	146,238.43	97,689	106,722	48,290	16.53	2,921
1987	219,381.67	144,843	158,237	74,308	16.56	4,487
1988	129,942.03	84,745	92,581	45,157	16.59	2,722
1989	210,175.64	135,345	147,860	74,926	16.61	4,511
1990	326,556.15	207,389	226,566	119,583	16.64	7,186
1991	378,859.70	237,164	259,095	142,497	16.66	8,553
1992	143,407.00	88,416	96,592	55,420	16.68	3,323
1993	213,117.96	129,213	141,161	84,744	16.71	5,071

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -6						
1994	243,236.46	144,911	158,311	99,520	16.73	5,949
1995	378,604.30	221,392	241,864	159,456	16.75	9,520
1996	132,026.00	75,665	82,662	57,286	16.77	3,416
1997	113,295.86	63,549	69,425	50,668	16.79	3,018
1998	16,759.09	9,183	10,032	7,732	16.81	460
1999	78,147.46	41,784	45,648	37,189	16.82	2,211
2000	12,638.00	6,575	7,183	6,213	16.84	369
2001	61,005.75	30,796	33,644	31,022	16.86	1,840
2003	211,552.31	99,780	109,007	115,239	16.89	6,823
2004	87,825.06	39,804	43,485	49,610	16.91	2,934
2005	126,190.46	54,738	59,800	73,962	16.92	4,371
2006	93,259.29	38,487	42,046	56,809	16.94	3,354
2007	109,967.17	42,952	46,924	69,641	16.95	4,109
2008	76,267.72	27,936	30,519	50,325	16.97	2,966
2009	25,225.68	8,585	9,379	17,360	16.98	1,022
2010	510,629.45	159,685	174,451	366,816	16.99	21,590
2011	184,777.66	52,072	56,887	138,977	17.01	8,170
2012	256,120.18	63,816	69,717	201,770	17.02	11,855
2013	319,773.21	68,205	74,512	264,448	17.03	15,528
2014	312,463.22	54,282	59,301	271,910	17.04	15,957
2015	417,186.02	54,340	59,365	382,852	17.06	22,442
2016	191,888.31	15,723	17,177	186,225	17.07	10,909
2017	189,493.25	5,490	5,998	194,865	17.08	11,409
	6,483,855.33	2,926,810	3,197,454	3,675,433		217,739
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1997	911,941.17	535,754	875,267	109,629	15.87	6,908
2000	2,454.00	1,340	2,189	461	15.92	29
2011	47,617.08	14,307	23,374	28,053	16.06	1,747
	962,012.25	551,401	900,830	138,143		8,684

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1974	1,024,130.37	786,277	1,059,220	46,840	15.28	3,065
1975	72,980.65	55,669	74,994	3,826	15.32	250
1976	12,253.24	9,285	12,508	725	15.35	47
1978	6,426.72	4,801	6,468	473	15.42	31
1983	4,043.88	2,897	3,903	465	15.57	30
1988	74,936.00	50,907	68,579	12,352	15.70	787
1989	2,178.22	1,462	1,970	383	15.72	24
1990	137,000.67	90,725	122,219	25,742	15.74	1,635
1994	52,592.00	32,748	44,116	12,683	15.82	802
1995	11,112.00	6,794	9,152	2,849	15.84	180
1996	153,652.05	92,185	124,186	41,759	15.85	2,635
1997	18,479.01	10,856	14,624	5,333	15.87	336
1998	2,709.00	1,556	2,096	830	15.89	52
1999	79,194.16	44,407	59,822	25,708	15.90	1,617
2000	2,880.81	1,573	2,119	992	15.92	62
2004	42,569.91	20,323	27,378	18,598	15.98	1,164
2006	30,770.07	13,421	18,080	15,152	16.00	947
2007	7,433.84	3,068	4,133	3,896	16.02	243
2013	68,502.65	15,573	20,979	53,004	16.09	3,294
2015	42,125.60	5,878	7,918	37,577	16.11	2,333
	1,845,970.85	1,250,405	1,684,463	309,186		19,534
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
1976	97,461.37	73,854	97,113	8,145	15.35	531
1977	661,648.39	497,798	654,571	60,010	15.39	3,899
1978	591,177.00	441,605	580,681	57,790	15.42	3,748
1985	6,645.13	4,669	6,139	1,037	15.62	66
1989	51,128.40	34,307	45,111	10,107	15.72	643
1990	7,692.02	5,094	6,698	1,609	15.74	102
1991	6,857.97	4,479	5,890	1,517	15.76	96
1992	50,988.28	32,809	43,142	11,926	15.78	756
2006	15,073.78	6,575	8,646	7,634	16.00	477
2007	7,433.84	3,068	4,034	3,994	16.02	249

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -8						
2013	17,365.58	3,948	5,191	13,563	16.09	843
2014	9,654.84	1,796	2,362	8,066	16.10	501
2017	30,383.39	948	1,247	31,568	16.13	1,957
	1,553,509.99	1,110,950	1,460,824	216,967		13,868
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -8						
1981	2,113,307.83	1,456,770	1,776,456	505,916	18.09	27,967
1982	219,540.39	149,857	182,743	54,361	18.13	2,998
1983	7,536.34	5,092	6,209	1,930	18.17	106
1984	599,875.00	400,951	488,939	158,926	18.21	8,727
1987	14,126.58	9,115	11,115	4,141	18.31	226
1988	8,279.00	5,271	6,428	2,514	18.35	137
1993	31,841.79	18,754	22,870	11,520	18.50	623
1994	1,429.72	826	1,007	537	18.53	29
2004	70,857.65	30,699	37,436	39,090	18.75	2,085
2007	56,110.00	20,799	25,363	35,235	18.81	1,873
2013	8,682.80	1,724	2,102	7,275	18.91	385
2014	824,923.38	133,335	162,595	728,322	18.92	38,495
2016	70,989.53	5,380	6,561	70,108	18.95	3,700
	4,027,500.01	2,238,573	2,729,825	1,619,875		87,351
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
1984	1,551,008.56	1,017,198	995,081	680,008	19.06	35,677
1985	75,061.39	48,660	47,602	33,464	19.10	1,752
1986	68,833.86	44,079	43,121	31,220	19.14	1,631
1987	194,430.24	122,923	120,250	89,734	19.18	4,679
1988	240,695.56	150,096	146,832	113,119	19.22	5,885
1989	281,911.30	173,347	169,578	134,886	19.25	7,007
1990	241,531.51	146,258	143,078	117,776	19.29	6,106
1991	236,117.05	140,751	137,691	117,316	19.32	6,072

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 75-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -8						
1992	186,806.00	109,504	107,123	94,627	19.35	4,890
1993	119,556.00	68,837	67,340	61,780	19.38	3,188
1994	89,879.11	50,765	49,661	47,408	19.41	2,442
1995	403,518.00	223,312	218,456	217,343	19.44	11,180
1996	153,670.60	83,195	81,386	84,578	19.47	4,344
1997	261,371.59	138,185	135,180	147,101	19.50	7,544
1998	36,015.00	18,574	18,170	20,726	19.52	1,062
1999	626,250.00	314,185	307,354	368,996	19.55	18,874
2000	69,931.00	34,078	33,337	42,188	19.57	2,156
2003	274,884.03	120,564	117,943	178,932	19.64	9,111
2004	259,074.19	108,825	106,459	173,341	19.67	8,812
2005	117,203.33	46,977	45,956	80,624	19.69	4,095
2006	15,073.78	5,735	5,610	10,669	19.71	541
2007	167,940.61	60,233	58,923	122,453	19.73	6,206
2008	38,302.23	12,841	12,562	28,805	19.75	1,458
2009	38,451.83	11,931	11,672	29,856	19.77	1,510
2010	820,549.05	232,776	227,715	658,478	19.79	33,273
2011	521,855.44	133,022	130,130	433,474	19.81	21,882
2012	694,925.41	155,748	152,362	598,158	19.82	30,180
2013	65,548.30	12,513	12,241	58,551	19.84	2,951
2014	109,379.77	16,876	16,509	101,621	19.86	5,117
2015	803,237.38	92,796	90,778	776,718	19.87	39,090
2016	381,116.80	27,606	27,006	384,600	19.89	19,336
2017	854,931.81	21,292	20,829	902,497	19.91	45,329
	9,999,060.73	3,943,682	3,857,934	6,941,052		353,380
	36,076,316.24	14,322,811	16,315,729	22,561,783		992,281

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.7   2.75

Exhibit JJS-LG&E-1

LG&E Depreciation Study

LOUISVILLE GAS AND ELECTRIC COMPANY

LOUISVILLE, KENTUCKY

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO STEAM GENERATION
PLANT AS OF DECEMBER 31, 2017

Prepared by:

Gannett Fleming

Excellence Delivered **As Promised**

LOUISVILLE GAS AND ELECTRIC COMPANY

Louisville, Kentucky

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO STEAM GENERATION PLANT AS OF DECEMBER 31, 2017

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Harrisburg, Pennsylvania

Gannett Fleming

Excellence Delivered As Promised

September 4, 2018

Louisville Gas and Electric Company
220 West Main Street, Suite 1400
Louisville, KY 40202-1345

Attention Christopher M. Garrett
Controller

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the steam generation plant of Louisville Gas and Electric Company as of December 31, 2017. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J. Spanos

JOHN J. SPANOS
Sr. Vice President

JJS:mle

063789.200

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LOUISVILLE GAS AND ELECTRIC COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Louisville Gas and Electric Company's ("LGE" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the steam generation plant as of December 31, 2017. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets.

LGE's accounting policy has not changed since the last depreciation study was prepared. However, there have been significant changes in past and future retirement plans of assets. These changes have caused the proposed remaining lives for many accounts to fluctuate from those proposed in the previous depreciation study as of December 31, 2015.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to steam generation plant in service as of December 31, 2017 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $114.2 million when applied to depreciable plant balances as of December 31, 2017.

PART I. INTRODUCTION

LOUISVILLE GAS AND ELECTRIC COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Louisville Gas and Electric Company ("Company"), as applied to specific steam generation plant in service as of December 31, 2017. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to current electric plant in service.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2017, the net salvage analyses of historical plant retirement data recorded through 2017, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric and gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For all accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts. For steam production plants, the life span technique was used. In this technique, the date of final retirement was estimated for each unit, and the estimated survivor curves applied to each vintage were truncated at ages coinciding with the date of final retirement.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The estimates of net salvage by account incorporated a review of experienced costs of removal and salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or 0) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment

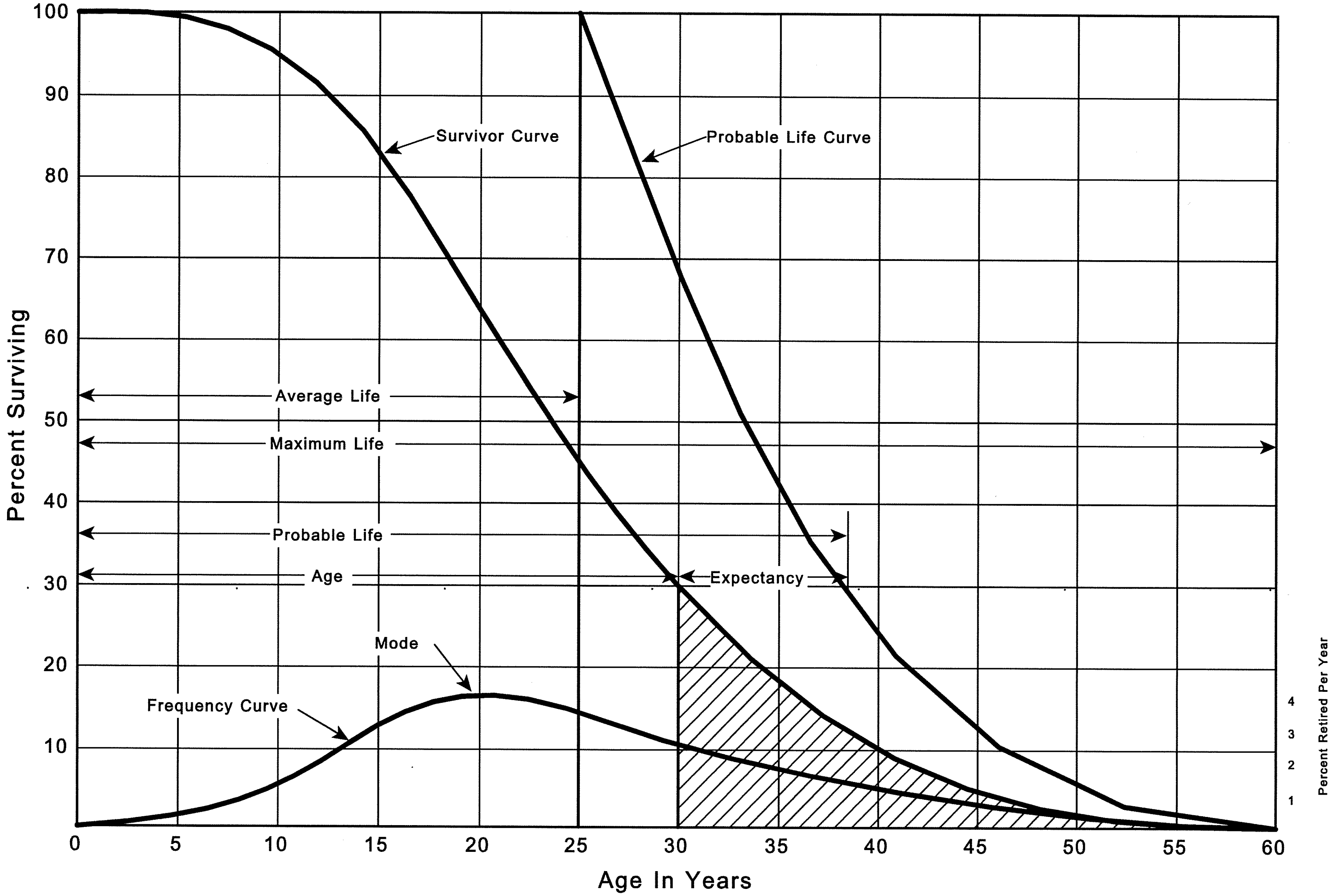


Figure 1. A Typical Survivor Curve and Derived Curves

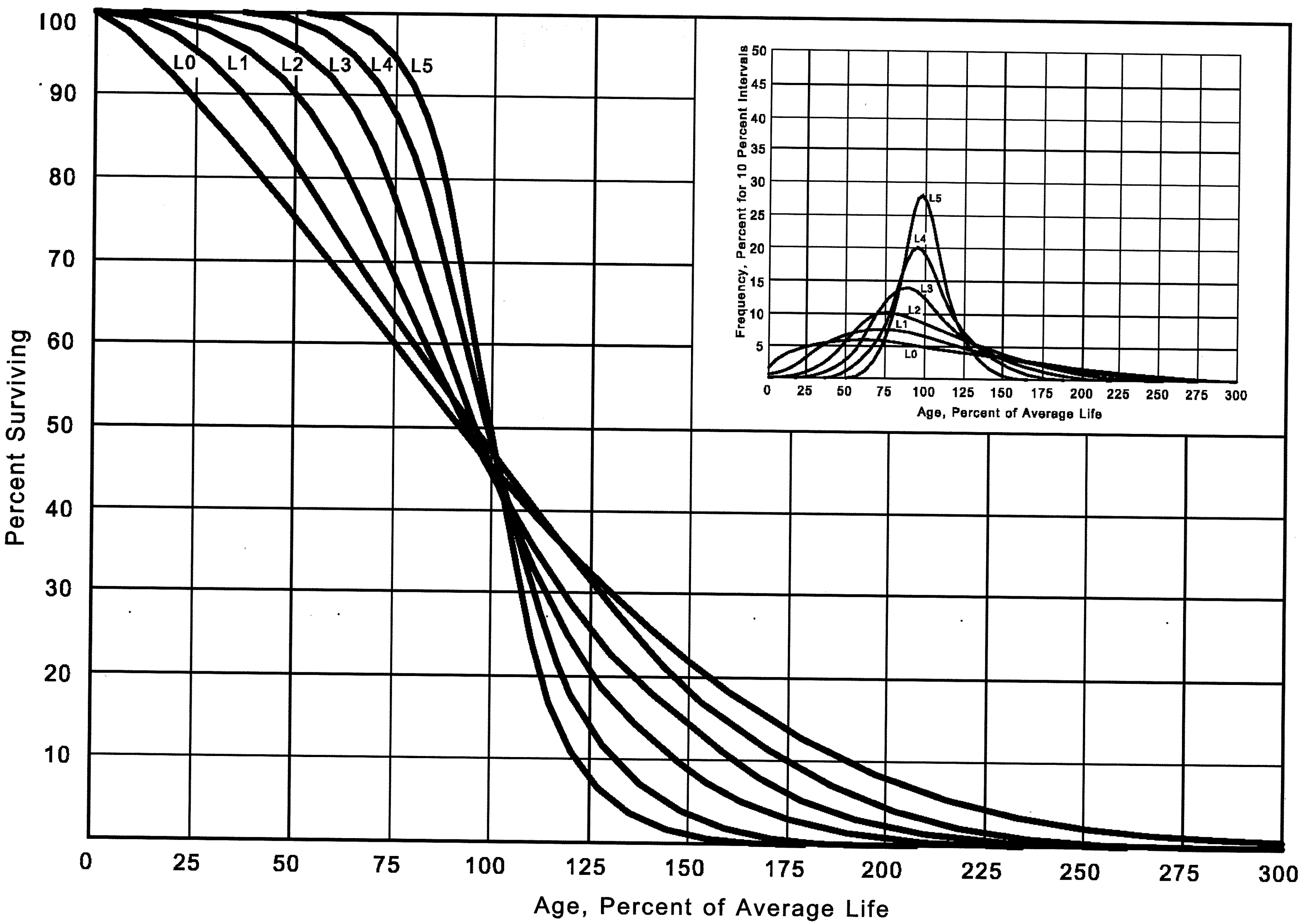


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

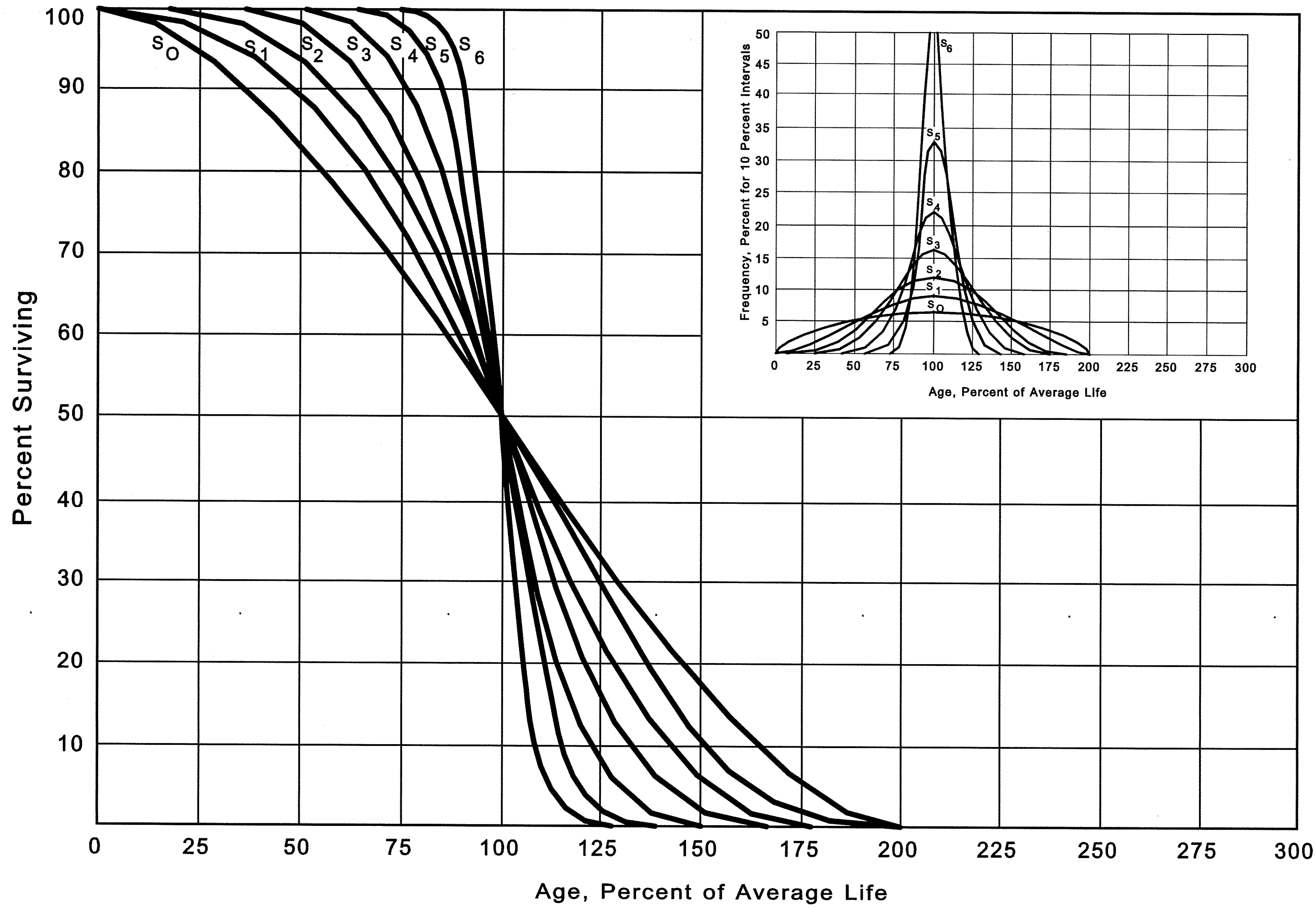


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

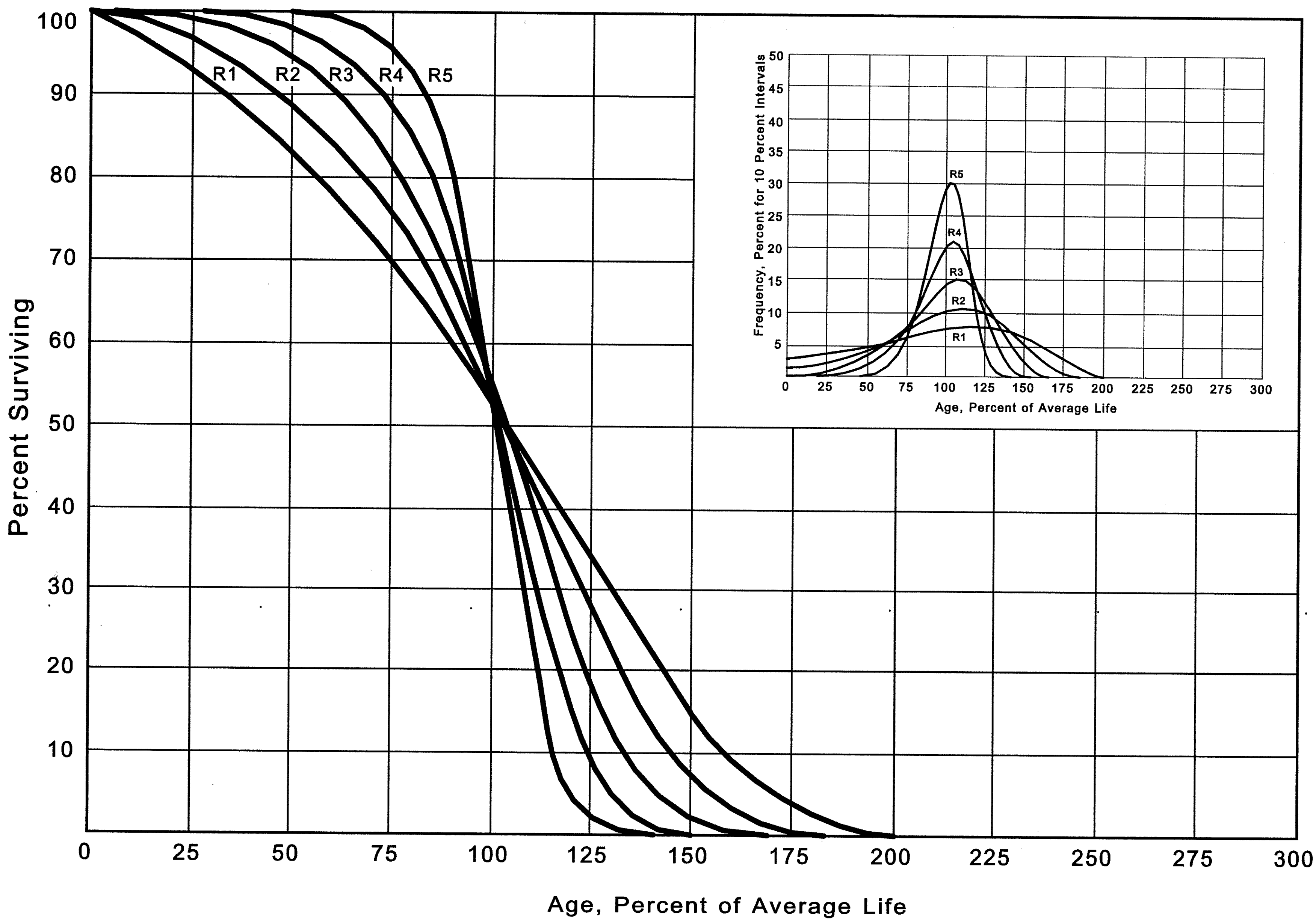


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

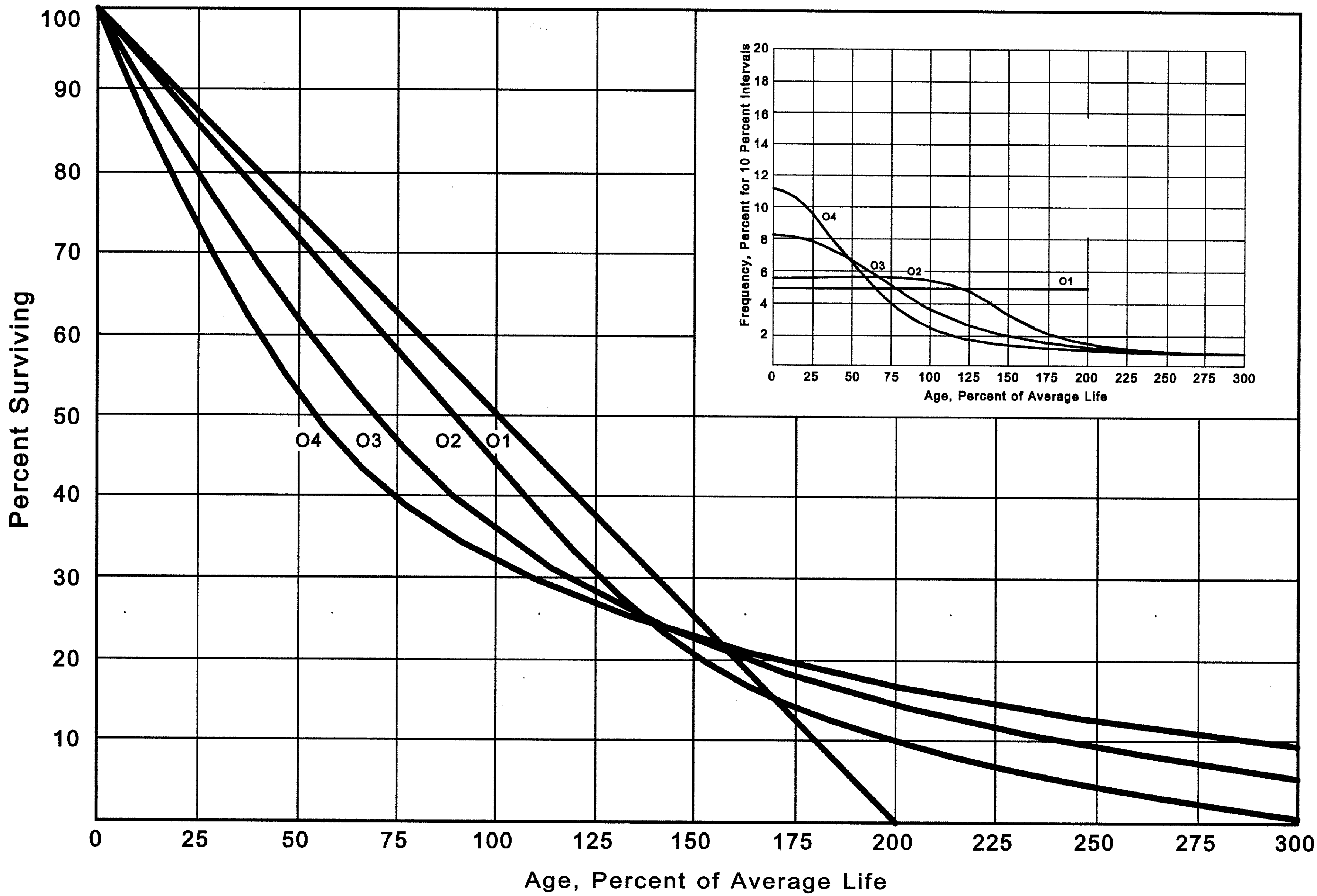


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Station's Bulletin 125. These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements"[2], "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows.

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[2]Winfrey, Roble, Statistical Analyses of Industrial Property Retirements. Iowa State College Engineering Experiment Station, Bulletin 125. 1935.
[3]Marston, Anson, Roble Winfrey, and Jean C. Hempstead, Supra Note 1.
[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½ - 5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2017 retirements of the 2012 installations. Thus, the total amount of 143 for age interval 4½ - 5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Year Placed (1)	Retirements, Thousands of Dollars During Year 2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total During Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 | Placement Band 2003-2017

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	6	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2008 through 2017 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or additions are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0 = amount of addition	= \$750,000
Exposures at age ½ = \$750,000 - \$8,000	= \$742,000
Exposures at age 1½ = \$742,000 - \$18,000	= \$724,000
Exposures at age 2½ = \$724,000 - \$20,000 - \$19,000	= \$685,000
Exposures at age 3½ = \$685,000 - \$22,000	= \$663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total at Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	926	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2008-2017, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½ - 5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15
Exposures at age 4½	=	3,789,000
Retirements from age 4½ to 5½	=	143,000
Retirement Ratio	=	143,000 ÷ 3,789,000 = 0.0377
Survivor Ratio	=	1.000 - 0.0377 = 0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623) = 84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017 Placement Band 2003-2017

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

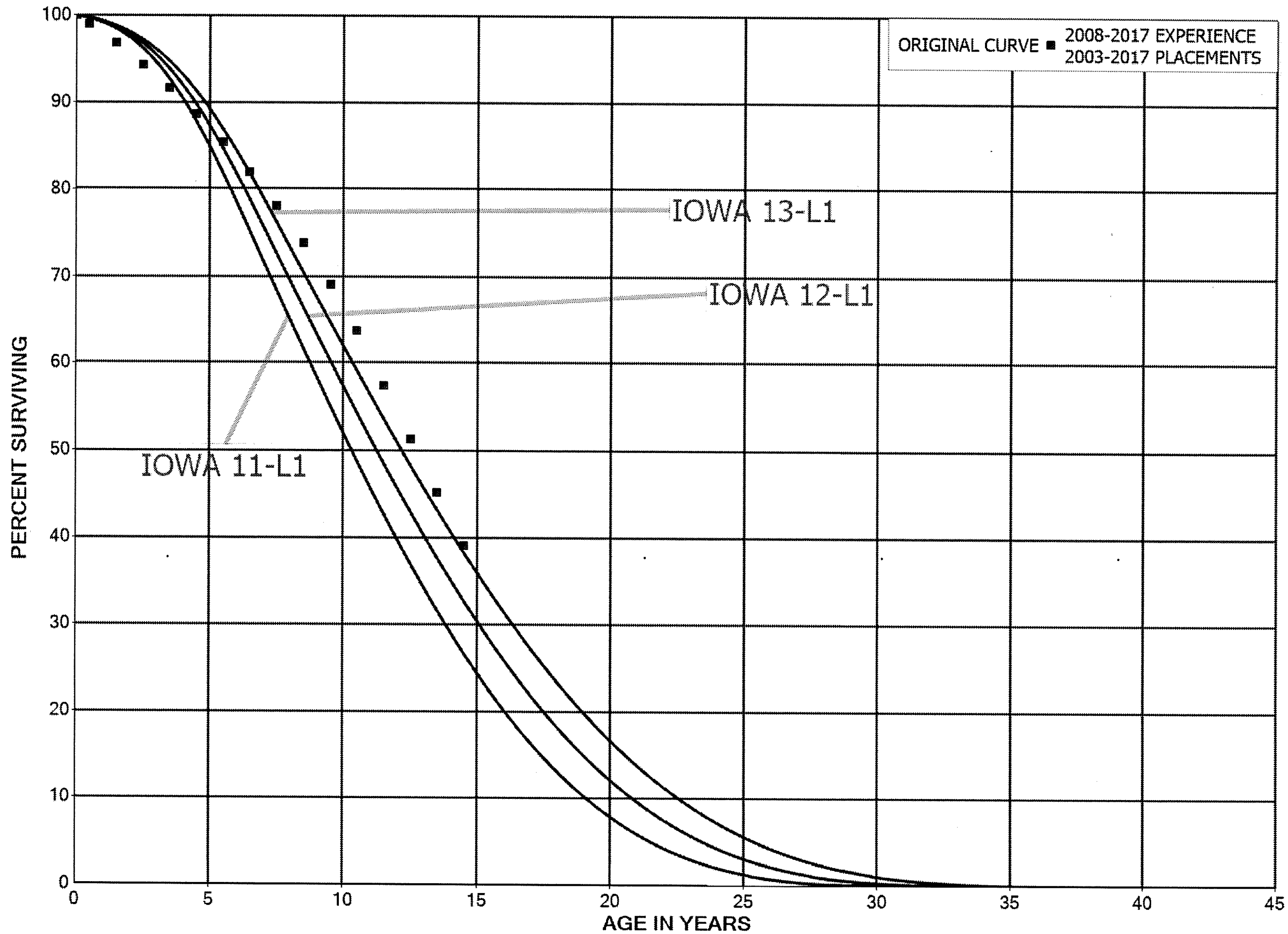


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

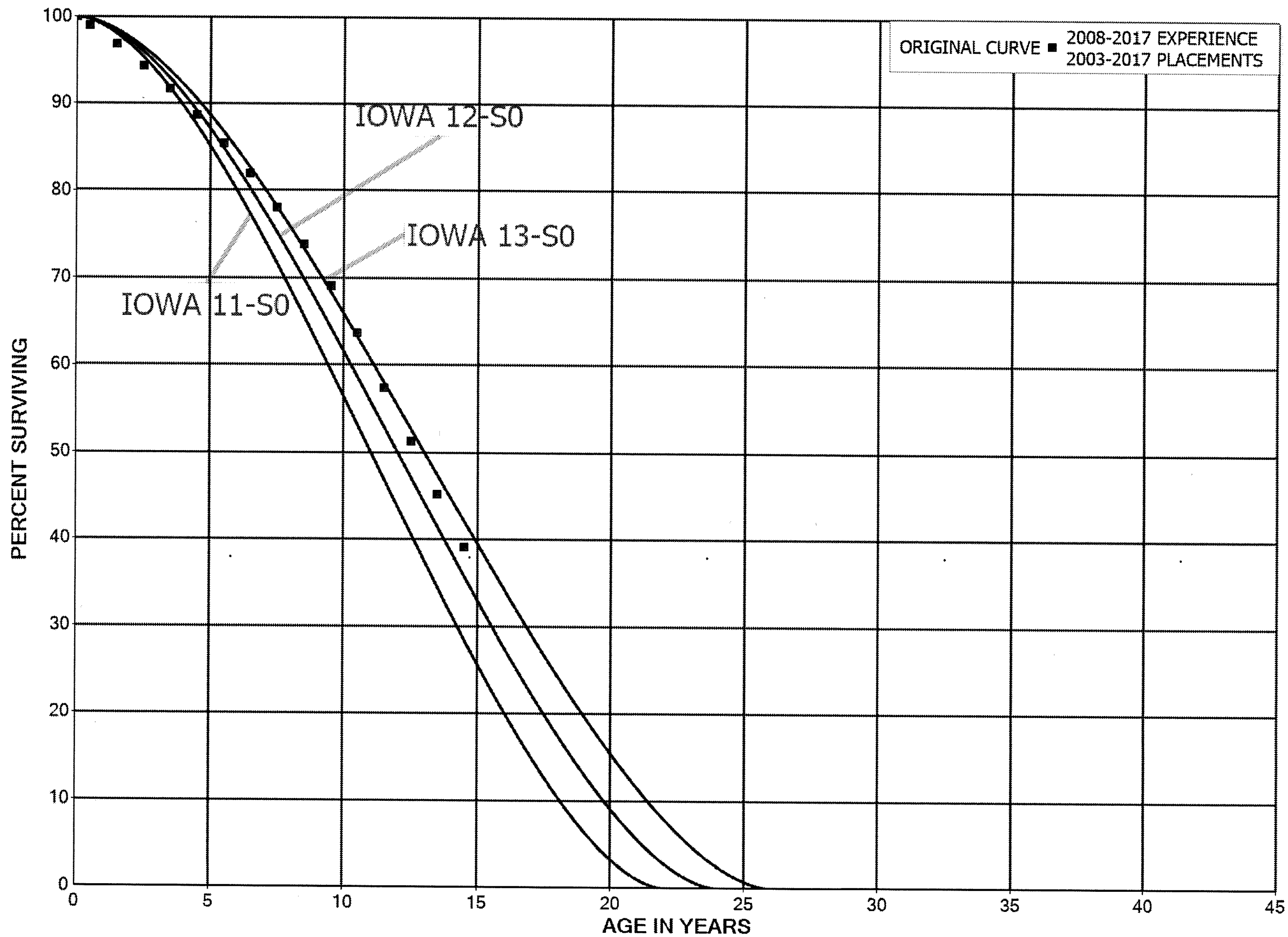


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

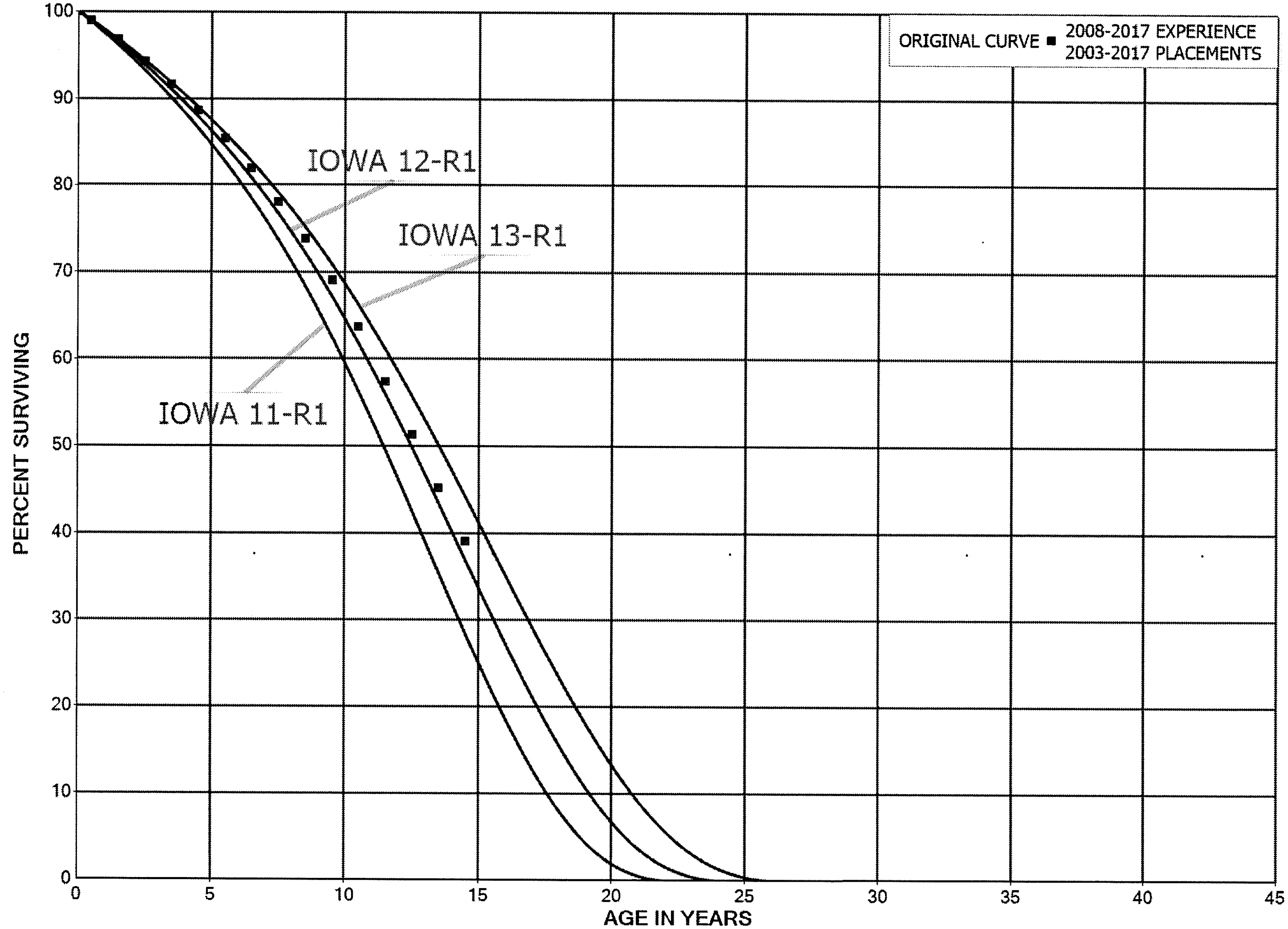
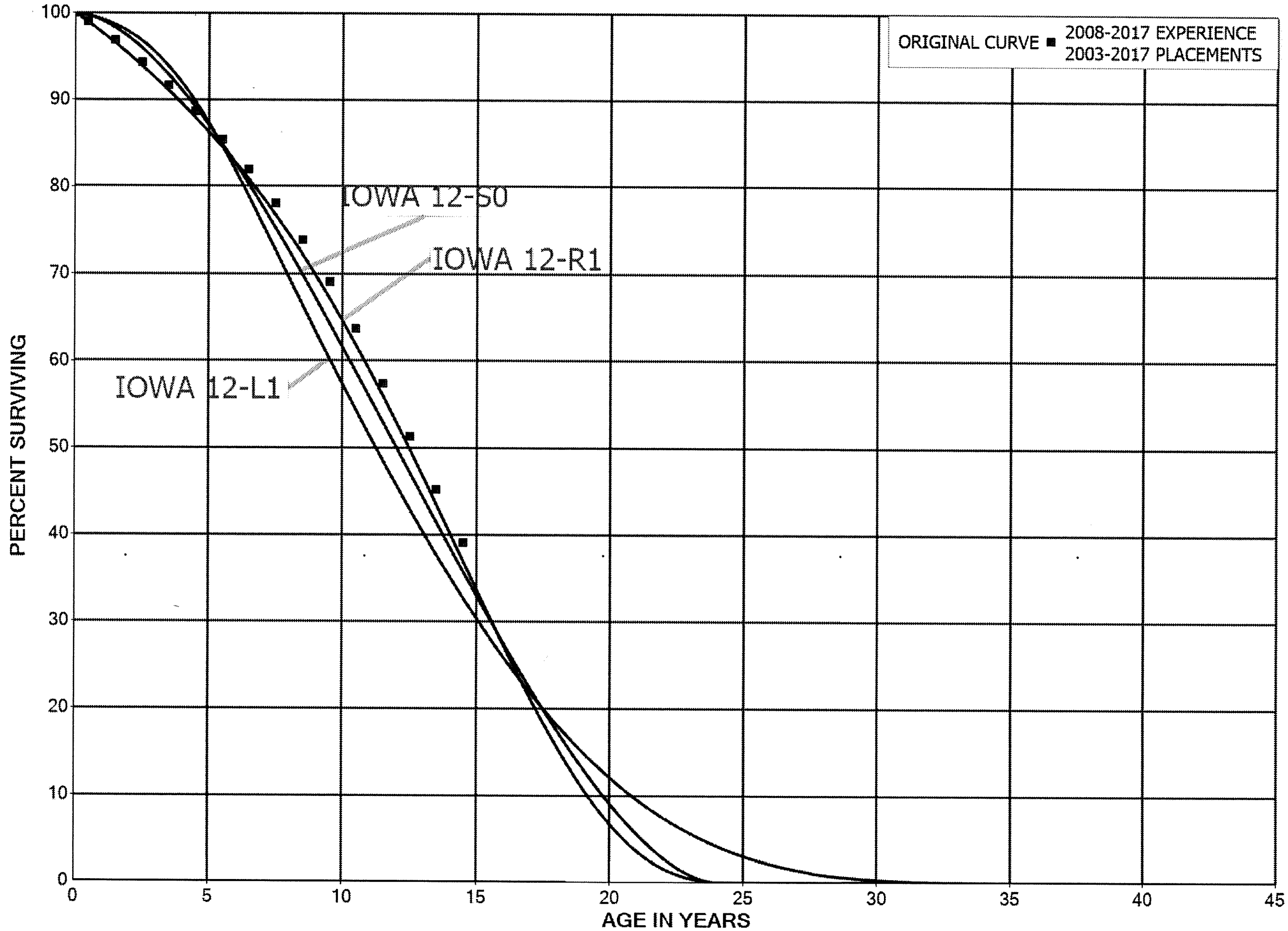


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted. A general understanding of the function of the plant and information with respect to the reasons forpast retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during recent field trips.

<u>October 19-21, 2015</u>
Mill Creek Generating Station
Mill Creek / Riverport Center
Cane Run Generating Facility

<u>October 10-12, 2011</u>
Mill Creek Generating Station
Cane Run Generating Facility
E.W. Brown Generating Facility
Trimble County Generating Facility

<u>April 23-25, 2007</u>
Trimble County Generating Facility
Mill Creek Generating Facility
Cane Run Generating Facility
E.W. Brown Generating Facility

SERVICE LIFE ANALYSIS

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data, current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric and gas utility companies.

For most plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. Generally, the information external to the statistics led to minimal or no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

ELECTRIC PLANT
STEAM PRODUCTION PLANT
311 Structures and Improvements
312 Boiler Plant Equipment
314 Turbogenerator Units
316 Miscellaneous Power Plant Equipment

Account 312, Boiler Plant Equipment is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Account 312 represents approximately 74 percent of the total depreciable steam generation plant. Aged plant accounting data have been compiled for the years 1952 through 2017. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate for Account 312, Boiler Plant Equipment, is based on the statistical indications for the periods 1952 through 2017. The Iowa 60-R1 is a good fit of the original survivor curve. The 60-year interim service life is within the typical service life range of 55 to 70 years for boiler plant equipment. The 60-year life reflects the Company's practices of continual and steady retirements for all vintages. The previous estimate was also the Iowa 54-R1.5.

Life Span Estimates

Inasmuch as production plant consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for steam production plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1954 through 2017.

The depreciable life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units and observed features and conditions at the time of the field visit. These life spans represent the expected depreciable life of each facility under their current configuration. The life span estimate for most steam, base-load units is 55 to 60 years, which is within the typical range of life spans for such units.

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Cane Run Unit 1	1954	2002	48
Cane Run Unit 2	1956	2002	46
Cane Run Unit 3	1958	2002	44
Cane Run Unit 4	1962	2015	53
Cane Run Unit 5	1966	2015	49
Cane Run Unit 6	1969	2015	46
Mill Creek Unit 1	1972	2032	60
Mill Creek Unit 2	1974	2034	60
Mill Creek Unit 3	1978	2038	60

Mill Creek Unit 4	1982	2042	60
Trimble County Unit 1	1990	2050	60
Trimble County Unit 2	1990,2011	2066	76,55

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled through 2017. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and salvage data are presented in the section titled "Net Salvage Statistics" for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period, 1972 through 2017 by plant account were analyzed. The analyses contributed significantly toward the net salvage estimates for most plant accounts, representing 99 percent of the depreciable plant, as follows:

ELECTRIC PLANT
STEAM PRODUCTION
311 Structures and Improvements
312 Boiler Plant Equipment
314 Turbogenerator Units
315 Accessory Electric Equipment
316 Miscellaneous Power Plant Equipment

The overall net salvage estimates for the Company's production facilities, for which the life span method is used, is based on estimates of both terminal net salvage and interim net salvage. Terminal net salvage is the net salvage experienced at the end of a production plant's life span. Interim net salvage is the net salvage experienced for interim retirements that occur prior to the final retirement of the plant. The terminal net salvage estimates in the study were based on decommissioning costs assigned to comparable facilities. The interim net salvage estimates were based in part on an analysis of historical interim retirement and net salvage data. Based on informed judgment that incorporated these interim net salvage analyses for each plant account, an interim net salvage estimate between 2 and 25 percent was used for each steam plant account.

The interim survivor curve estimates for each account and production facility were used to calculate the percentage of plant expected to be retired as interim retirements and terminal retirements. These are shown on Table 2 in the Net Salvage Statistics section on page VIII-2. These percentages were used to determine the weighted net salvage estimate for each account and production facility based on the interim and terminal net salvage estimates. These calculations, as well as the estimated terminal net salvage amounts and interim net salvage percents, are shown on Table 2 of the Net Salvage Statistics section on page VIII-2.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2017, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2017, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Service\ Life}{Average\ Service\ Life}$$

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the steam generation plant in service as of December 31, 2017. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2017, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of salvage data are presented in the section titled, "Net Salvage Statistics". The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of steam generation plant as of December 31, 2017, is presented on pages VI-4 and VI-5 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount.

LOUISVILLE GAS AND ELECTRIC COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	DEPRECIABLE PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	RIVERPORT DISTRIBUTION CENTER	95-R2.5	*	(25)	5,310,284.64	406,568	6,231,288	141,508	2.66	44.0
	MILL CREEK UNIT 1	95-R2.5	*	(10)	21,232,083.22	18,030,458	5,324,834	373,169	1.76	14.3
	MILL CREEK UNIT 2	95-R2.5	*	(10)	14,161,012.84	10,257,954	5,319,160	327,519	2.31	16.2
	MILL CREEK UNIT 2 SCRUBBER	95-R2.5	*	(10)	4,970,628.17	908,754	4,558,937	278,626	5.61	16.4
	MILL CREEK UNIT 3	95-R2.5	*	(10)	29,123,290.17	21,313,461	10,722,158	532,654	1.83	20.1
	MILL CREEK UNIT 3 SCRUBBER	95-R2.5	*	(10)	5,494,516.28	173,524	5,870,444	288,893	5.26	20.3
	MILL CREEK UNIT 4	95-R2.5	*	(10)	73,280,911.39	41,957,732	38,651,271	1,620,533	2.21	23.9
	MILL CREEK UNIT 4 SCRUBBER	95-R2.5	*	(10)	5,792,375.79	2,461,633	3,909,980	162,299	2.80	24.1
	TRIMBLE COUNTY UNIT 1	95-R2.5	*	(14)	107,482,423.29	66,335,130	56,194,833	1,810,718	1.68	31.0
	TRIMBLE COUNTY UNIT 1 SCRUBBER	95-R2.5	*	(14)	889,015.22	6,671	1,006,806	31,696	3.57	31.8
	TRIMBLE COUNTY UNIT 2	95-R2.5	*	(14)	17,403,381.00	2,319,428	17,520,426	375,655	2.16	46.6
	TRIMBLE COUNTY UNIT 2 SCRUBBER	95-R2.5	*	(14)	84,599.93	7,610	88,834	1,903	2.25	46.7
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				285,224,521.94	164,178,923	155,398,971	5,945,173	2.08	26.1
311.20	STRUCTURES AND IMPROVEMENTS - RETIRED PLANT									
	CANE RUN UNIT 1	95-R2.5	*	(10)	1,786,178.29	1,964,796	0	0	-	-
	CANE RUN UNIT 2	95-R2.5	*	(10)	1,228,338.33	1,351,172	0	0	-	-
	CANE RUN UNIT 3	95-R2.5	*	(10)	2,035,561.33	2,239,117	0	0	-	-
	CANE RUN UNIT 4	95-R2.5	*	(10)	3,131,855.49	3,445,041	0	0	-	-
	CANE RUN UNIT 4 SCRUBBER	95-R2.5	*	(10)	17,565.79	19,322	0	0	-	-
	CANE RUN UNIT 5	95-R2.5	*	(10)	3,145,664.22	3,460,231	0	0	-	-
	CANE RUN UNIT 5 SCRUBBER	95-R2.5	*	(10)	10,193.27	11,213	0	0	-	-
	CANE RUN UNIT 6	95-R2.5	*	(10)	13,104,413.12	14,414,854	0	0	-	-
	CANE RUN UNIT 6 SCRUBBER	95-R2.5	*	(10)	85,926.95	94,520	0	0	-	-
	TOTAL ACCOUNT 311.2 - STRUCTURES AND IMPROVEMENTS - RETIRED PLANT				24,545,696.79	27,000,266	0	0	-	-
312.00	BOILER PLANT EQUIPMENT									
	MILL CREEK UNIT 1	60-R1	*	(10)	182,136,143.11	44,904,210	155,445,547	11,206,606	6.15	13.9
	MILL CREEK UNIT 1 SCRUBBER	60-R1	*	(10)	16,929,429.83	10,096,169	8,526,204	621,587	3.67	13.7
	MILL CREEK UNIT 2	60-R1	*	(10)	198,502,284.71	23,329,610	195,022,903	12,436,596	6.27	15.7
	MILL CREEK UNIT 2 SCRUBBER	60-R1	*	(10)	114,821,991.46	3,293,371	123,010,820	7,785,517	6.78	15.8
	MILL CREEK UNIT 3	60-R1	*	(10)	277,512,948.88	68,045,505	237,218,739	12,394,515	4.47	19.1
	MILL CREEK UNIT 3 SCRUBBER	60-R1	*	(10)	150,336,700.73	3,777,361	161,593,010	8,327,797	5.54	19.4
	MILL CREEK UNIT 4	60-R1	*	(10)	471,456,638.57	135,726,909	382,875,393	17,032,057	3.61	22.5
	MILL CREEK UNIT 4 SCRUBBER	60-R1	*	(10)	206,349,248.58	17,667,770	209,316,403	9,217,917	4.47	22.7
	TRIMBLE COUNTY UNIT 1	60-R1	*	(14)	322,917,528.20	90,641,330	277,484,652	9,742,924	3.02	28.5
	TRIMBLE COUNTY UNIT 1 SCRUBBER	60-R1	*	(14)	66,837,564.03	33,565,110	42,629,713	1,543,467	2.31	27.6
	TRIMBLE COUNTY UNIT 2	60-R1	*	(14)	146,448,004.91	25,449,556	141,501,170	3,498,812	2.39	40.4
	TRIMBLE COUNTY UNIT 2 SCRUBBER	60-R1	*	(14)	15,152,263.48	3,036,129	14,237,451	352,682	2.33	40.4
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				2,169,400,746.49	459,533,030	1,948,862,005	94,160,477	4.34	20.7

LOUISVILLE GAS AND ELECTRIC COMPANY

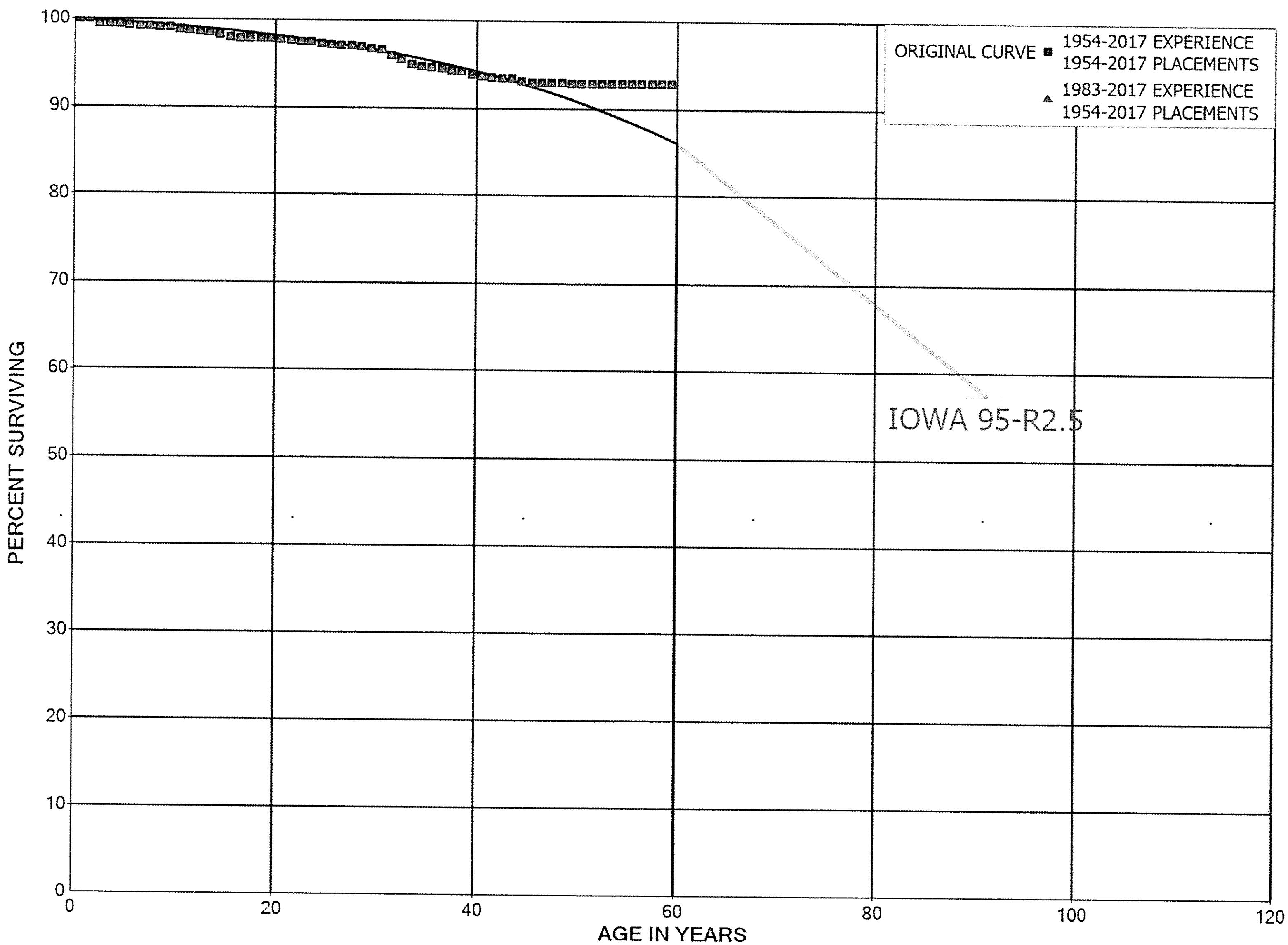
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2017

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
312.10	BOILER PLANT EQUIPMENT - ASH PONDS								
	MILL CREEK UNIT 1	100-S4 *	0	411,750.29	231,546	180,204	45,051	10.94	4.0
	MILL CREEK UNIT 3	100-S4 *	0	947,826.39	635,948	311,878	207,919	21.94	1.5
	TRIMBLE COUNTY UNIT 1	100-S4 *	0	4,867,827.96	1,858,074	3,009,754	501,626	10.30	6.0
	TRIMBLE COUNTY UNIT 2	100-S4 *	0	5,057,242.50	614,262	4,442,980	1,110,745	21.96	4.0
	TOTAL ACCOUNT 312.1 - BOILER PLANT EQUIPMENT - ASH PONDS			11,284,647.14	3,339,830	7,944,816	1,865,341	16.53	4.3
314.00	TURBOGENERATOR UNITS								
	MILL CREEK UNIT 1	60-R2.5 *	(10)	25,971,344.84	11,394,423	17,174,056	1,234,951	4.76	13.9
	MILL CREEK UNIT 2	60-R2.5 *	(10)	28,261,136.61	12,265,240	18,822,010	1,191,889	4.22	15.8
	MILL CREEK UNIT 3	60-R2.5 *	(10)	34,874,136.89	20,843,142	17,518,409	917,070	2.63	19.1
	MILL CREEK UNIT 4	60-R2.5 *	(10)	55,058,036.33	24,696,491	35,867,349	1,583,295	2.88	22.7
	TRIMBLE COUNTY UNIT 1	60-R2.5 *	(14)	59,537,576.82	30,778,475	37,094,363	1,294,397	2.17	28.7
	TRIMBLE COUNTY UNIT 2	60-R2.5 *	(14)	21,967,018.06	4,789,217	20,253,184	485,677	2.21	41.7
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS			225,669,249.55	104,766,988	146,729,371	6,707,279	2.97	21.9
315.00	ACCESSORY ELECTRIC EQUIPMENT								
	MILL CREEK UNIT 1	65-R3 *	(10)	18,582,082.97	11,727,023	8,713,268	615,932	3.31	14.1
	MILL CREEK UNIT 1 SCRUBBER	65-R3 *	(10)	202,167.22	220,362	2,022	147	0.07	13.8
	MILL CREEK UNIT 2	65-R3 *	(10)	13,147,191.98	6,468,006	7,993,905	495,902	3.77	16.1
	MILL CREEK UNIT 2 SCRUBBER	65-R3 *	(10)	2,694,916.35	765,601	2,198,807	133,992	4.97	16.4
	MILL CREEK UNIT 3	65-R3 *	(10)	26,791,012.14	13,984,708	15,485,405	775,355	2.89	20.0
	MILL CREEK UNIT 3 SCRUBBER	65-R3 *	(10)	9,792,181.78	1,349,963	9,421,437	464,826	4.75	20.3
	MILL CREEK UNIT 4	65-R3 *	(10)	31,002,634.31	18,728,455	15,374,443	669,720	2.16	23.0
	MILL CREEK UNIT 4 SCRUBBER	65-R3 *	(10)	1,667,316.69	564,201	1,269,847	52,480	3.15	24.2
	TRIMBLE COUNTY UNIT 1	65-R3 *	(14)	65,098,801.60	30,167,182	44,045,452	1,473,149	2.26	29.9
	TRIMBLE COUNTY UNIT 1 SCRUBBER	65-R3 *	(14)	2,736,920.21	2,395,614	724,475	25,313	0.92	28.6
	TRIMBLE COUNTY UNIT 2	65-R3 *	(14)	10,679,138.16	1,552,448	10,621,770	235,871	2.21	45.0
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT			182,394,363.41	87,923,563	115,850,831	4,942,687	2.71	23.4
316.00	MISCELLANEOUS PLANT EQUIPMENT								
	RIVERPORT DISTRIBUTION CENTER	45-R2.5 *	(2)	582,917.96	63,737	530,839	14,119	2.42	37.6
	MILL CREEK UNIT 1	45-R2.5 *	(10)	1,036,757.76	560,951	579,483	43,834	4.23	13.2
	MILL CREEK UNIT 2	45-R2.5 *	(10)	141,316.22	90,413	65,035	4,487	3.18	14.5
	MILL CREEK UNIT 3	45-R2.5 *	(10)	347,546.48	334,551	47,750	2,671	0.77	17.9
	MILL CREEK UNIT 4	45-R2.5 *	(10)	10,935,346.35	3,654,057	8,374,824	379,457	3.47	22.1
	MILL CREEK UNIT 4 SCRUBBER	45-R2.5 *	(10)	43,211.57	47,101	432	19	0.04	22.7
	TRIMBLE COUNTY UNIT 1	45-R2.5 *	(14)	3,093,853.20	1,635,209	1,891,784	80,052	2.59	23.6
	TRIMBLE COUNTY UNIT 2	45-R2.5 *	(14)	3,528,603.03	384,869	3,637,738	94,925	2.69	38.3
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT			19,709,552.57	6,770,888	15,127,885	619,564	3.14	24.4
	TOTAL STEAM PRODUCTION PLANT			**2,918,228,777.89**	**853,513,488**	**2,389,913,879**	**114,240,521**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

PART VII. SERVICE LIFE STATISTICS

LOUISVILLE GAS AND ELECTRIC COMPANY
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1954-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	561,872,240		0.0000	1.0000	100.00
0.5	422,004,684	2,378	0.0000	1.0000	100.00
1.5	408,751,837	2,292,428	0.0056	0.9944	100.00
2.5	379,619,440	6,033	0.0000	1.0000	99.44
3.5	367,922,369	343,352	0.0009	0.9991	99.44
4.5	359,583,939	136,120	0.0004	0.9996	99.34
5.5	359,858,260	554,806	0.0015	0.9985	99.31
6.5	340,560,660	25,433	0.0001	0.9999	99.15
7.5	336,864,517	166,303	0.0005	0.9995	99.15
8.5	335,394,024	115,497	0.0003	0.9997	99.10
9.5	334,016,682	890,814	0.0027	0.9973	99.06
10.5	330,702,903	333,179	0.0010	0.9990	98.80
11.5	328,902,985	420,229	0.0013	0.9987	98.70
12.5	325,404,339	349,658	0.0011	0.9989	98.57
13.5	324,781,485	448,080	0.0014	0.9986	98.47
14.5	321,961,072	1,056,291	0.0033	0.9967	98.33
15.5	319,347,512	573,233	0.0018	0.9982	98.01
16.5	317,089,623	28,724	0.0001	0.9999	97.83
17.5	315,646,193	117,644	0.0004	0.9996	97.82
18.5	313,521,448	13,466	0.0000	1.0000	97.79
19.5	266,619,095	104,731	0.0004	0.9996	97.78
20.5	264,809,698	311,383	0.0012	0.9988	97.74
21.5	263,380,701	242,318	0.0009	0.9991	97.63
22.5	261,296,365	209,903	0.0008	0.9992	97.54
23.5	256,979,710	544,897	0.0021	0.9979	97.46
24.5	252,293,444	343,618	0.0014	0.9986	97.26
25.5	256,544,085	47,649	0.0002	0.9998	97.12
26.5	251,319,915	174,456	0.0007	0.9993	97.10
27.5	148,074,202	159,143	0.0011	0.9989	97.04
28.5	147,987,914	355,792	0.0024	0.9976	96.93
29.5	153,951,061	215,544	0.0014	0.9986	96.70
30.5	146,352,264	923,828	0.0063	0.9937	96.56
31.5	165,702,430	804,907	0.0049	0.9951	95.96
32.5	159,968,682	882,501	0.0055	0.9945	95.49
33.5	117,533,376	346,114	0.0029	0.9971	94.96
34.5	101,219,524	22,276	0.0002	0.9998	94.68
35.5	75,123,120	162,904	0.0022	0.9978	94.66
36.5	72,720,653	168,210	0.0023	0.9977	94.46
37.5	52,400,270	48,803	0.0009	0.9991	94.24
38.5	51,760,331	199,737	0.0039	0.9961	94.15

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1954-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	50,759,340	71,655	0.0014	0.9986	93.79
40.5	59,773,651	67,352	0.0011	0.9989	93.65
41.5	48,799,713	52,860	0.0011	0.9989	93.55
42.5	37,753,327	28,313	0.0007	0.9993	93.45
43.5	39,565,374	153,984	0.0039	0.9961	93.38
44.5	38,763,831	34,661	0.0009	0.9991	93.01
45.5	25,049,516	367	0.0000	1.0000	92.93
46.5	19,660,184	4,059	0.0002	0.9998	92.93
47.5	17,350,403		0.0000	1.0000	92.91
48.5	18,884,659	12,026	0.0006	0.9994	92.91
49.5	14,777,933	780	0.0001	0.9999	92.85
50.5	12,572,660		0.0000	1.0000	92.85
51.5	14,387,257	520	0.0000	1.0000	92.85
52.5	14,353,696		0.0000	1.0000	92.84
53.5	9,449,870	742	0.0001	0.9999	92.84
54.5	9,449,128		0.0000	1.0000	92.84
55.5	9,448,869		0.0000	1.0000	92.84
56.5	11,398,967		0.0000	1.0000	92.84
57.5	8,011,280		0.0000	1.0000	92.84
58.5	6,058,719		0.0000	1.0000	92.84
59.5	5,183,043		0.0000	1.0000	92.84
60.5	6,822,233		0.0000	1.0000	92.84
61.5	1,639,190		0.0000	1.0000	92.84
62.5					92.84

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	438,246,112		0.0000	1.0000	100.00
0.5	328,815,313	741	0.0000	1.0000	100.00
1.5	324,715,342	2,278,503	0.0070	0.9930	100.00
2.5	300,599,845	1,815	0.0000	1.0000	99.30
3.5	290,260,002	152,674	0.0005	0.9995	99.30
4.5	303,492,513	83,675	0.0003	0.9997	99.25
5.5	305,467,913	544,210	0.0018	0.9982	99.22
6.5	287,022,532	21,553	0.0001	0.9999	99.04
7.5	284,306,059	151,446	0.0005	0.9995	99.03
8.5	293,801,710	92,107	0.0003	0.9997	98.98
9.5	294,250,650	861,173	0.0029	0.9971	98.95
10.5	306,888,467	328,315	0.0011	0.9989	98.66
11.5	305,172,733	406,622	0.0013	0.9987	98.55
12.5	301,925,789	302,386	0.0010	0.9990	98.42
13.5	306,754,668	442,048	0.0014	0.9986	98.32
14.5	303,966,395	960,937	0.0032	0.9968	98.18
15.5	302,181,613	573,233	0.0019	0.9981	97.87
16.5	304,033,417	26,493	0.0001	0.9999	97.69
17.5	302,599,419	115,644	0.0004	0.9996	97.68
18.5	300,499,401	9,508	0.0000	1.0000	97.64
19.5	253,622,616	104,731	0.0004	0.9996	97.64
20.5	255,122,854	310,892	0.0012	0.9988	97.60
21.5	253,695,700	242,318	0.0010	0.9990	97.48
22.5	251,611,623	205,750	0.0008	0.9992	97.39
23.5	247,301,288	544,897	0.0022	0.9978	97.31
24.5	246,024,690	342,525	0.0014	0.9986	97.09
25.5	250,276,719	47,432	0.0002	0.9998	96.96
26.5	247,131,854	172,456	0.0007	0.9993	96.94
27.5	143,888,141	159,143	0.0011	0.9989	96.87
28.5	147,987,914	355,792	0.0024	0.9976	96.76
29.5	153,951,061	215,544	0.0014	0.9986	96.53
30.5	146,352,264	923,828	0.0063	0.9937	96.40
31.5	165,702,430	804,907	0.0049	0.9951	95.79
32.5	159,968,682	882,501	0.0055	0.9945	95.32
33.5	117,533,376	346,114	0.0029	0.9971	94.80
34.5	101,219,524	22,276	0.0002	0.9998	94.52
35.5	75,123,120	162,904	0.0022	0.9978	94.50
36.5	72,720,653	168,210	0.0023	0.9977	94.29
37.5	52,400,270	48,803	0.0009	0.9991	94.07
38.5	51,760,331	199,737	0.0039	0.9961	93.99

LOUISVILLE GAS AND ELECTRIC COMPANY

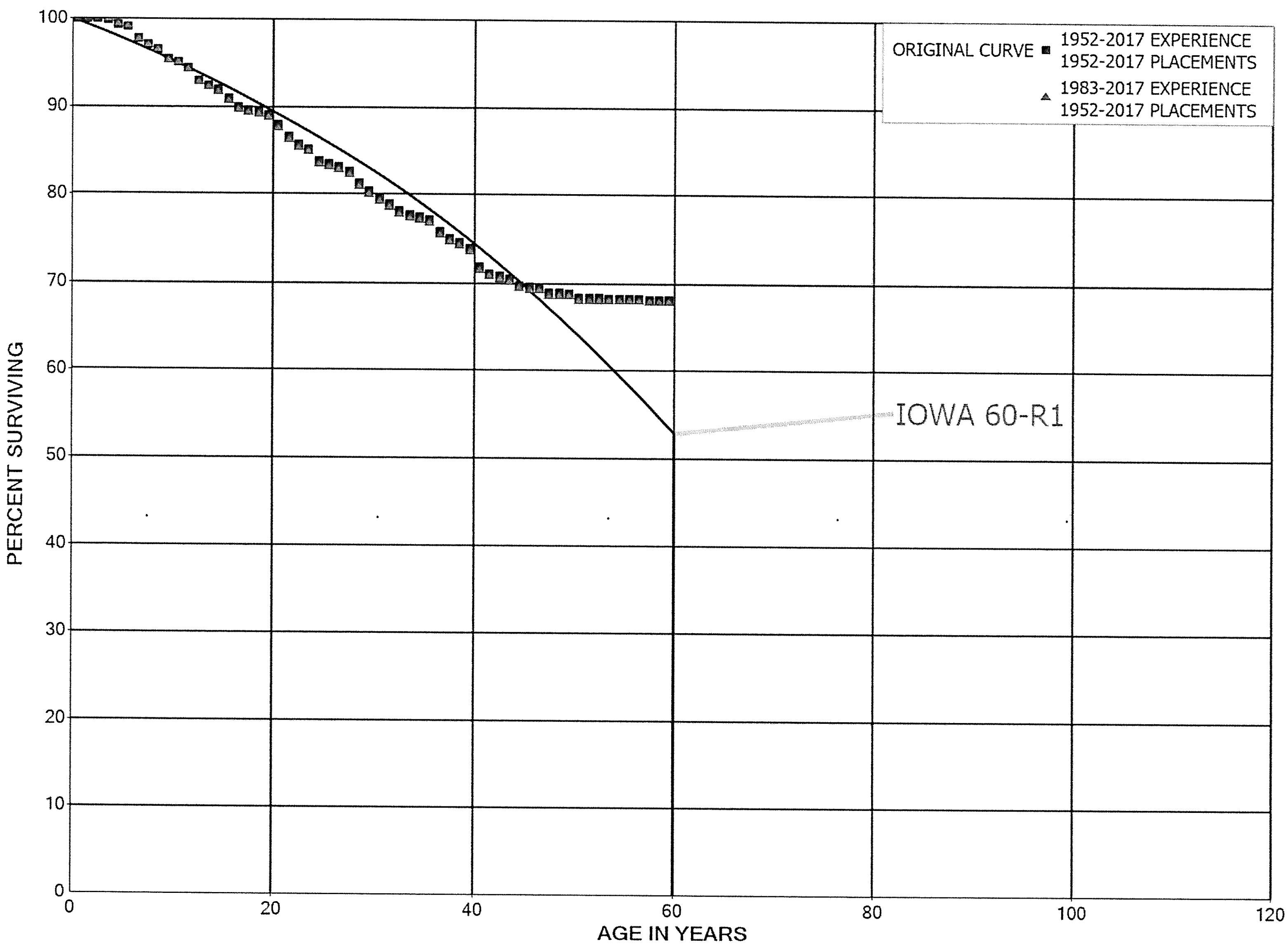
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	50,759,340	71,655	0.0014	0.9986	93.62
40.5	59,773,651	67,352	0.0011	0.9989	93.49
41.5	48,799,713	52,860	0.0011	0.9989	93.39
42.5	37,753,327	28,313	0.0007	0.9993	93.28
43.5	39,565,374	153,984	0.0039	0.9961	93.21
44.5	38,763,831	34,661	0.0009	0.9991	92.85
45.5	25,049,516	367	0.0000	1.0000	92.77
46.5	19,660,184	4,059	0.0002	0.9998	92.77
47.5	17,350,403		0.0000	1.0000	92.75
48.5	18,884,659	12,026	0.0006	0.9994	92.75
49.5	14,777,933	780	0.0001	0.9999	92.69
50.5	12,572,660		0.0000	1.0000	92.68
51.5	14,387,257	520	0.0000	1.0000	92.68
52.5	14,353,696		0.0000	1.0000	92.68
53.5	9,449,870	742	0.0001	0.9999	92.68
54.5	9,449,128		0.0000	1.0000	92.67
55.5	9,448,869		0.0000	1.0000	92.67
56.5	11,398,967		0.0000	1.0000	92.67
57.5	8,011,280		0.0000	1.0000	92.67
58.5	6,058,719		0.0000	1.0000	92.67
59.5	5,183,043		0.0000	1.0000	92.67
60.5	6,822,233		0.0000	1.0000	92.67
61.5	1,639,190		0.0000	1.0000	92.67
62.5					92.67

LOUISVILLE GAS AND ELECTRIC COMPANY
ACCOUNT 312 BOILER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1952-2017 EXPERIENCE BAND 1952-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,707,403,260		0.0000	1.0000	100.00
0.5	2,786,788,448	480,543	0.0002	0.9998	100.00
1.5	2,496,902,335	459,995	0.0002	0.9998	99.98
2.5	2,034,247,806	2,784,110	0.0014	0.9986	99.96
3.5	1,641,604,797	9,178,033	0.0056	0.9944	99.83
4.5	1,625,713,704	2,461,291	0.0015	0.9985	99.27
5.5	1,597,031,546	23,294,055	0.0146	0.9854	99.12
6.5	1,387,627,088	8,515,928	0.0061	0.9939	97.67
7.5	1,365,575,017	7,947,117	0.0058	0.9942	97.07
8.5	1,346,035,889	15,972,048	0.0119	0.9881	96.51
9.5	1,309,538,234	3,477,128	0.0027	0.9973	95.36
10.5	1,292,455,770	10,006,538	0.0077	0.9923	95.11
11.5	1,141,263,298	17,102,402	0.0150	0.9850	94.37
12.5	1,165,078,871	6,765,447	0.0058	0.9942	92.96
13.5	1,112,424,783	6,108,868	0.0055	0.9945	92.42
14.5	996,543,673	10,532,081	0.0106	0.9894	91.91
15.5	944,208,864	10,067,959	0.0107	0.9893	90.94
16.5	854,087,806	3,264,975	0.0038	0.9962	89.97
17.5	804,655,510	1,806,544	0.0022	0.9978	89.63
18.5	781,911,651	3,020,063	0.0039	0.9961	89.43
19.5	688,102,549	9,050,349	0.0132	0.9868	89.08
20.5	663,038,004	9,839,679	0.0148	0.9852	87.91
21.5	643,227,514	6,834,499	0.0106	0.9894	86.60
22.5	622,421,817	3,445,702	0.0055	0.9945	85.68
23.5	618,425,602	9,729,864	0.0157	0.9843	85.21
24.5	632,438,066	2,383,499	0.0038	0.9962	83.87
25.5	608,517,008	3,113,542	0.0051	0.9949	83.55
26.5	597,073,047	3,745,518	0.0063	0.9937	83.13
27.5	389,549,779	6,354,700	0.0163	0.9837	82.60
28.5	349,643,011	3,670,672	0.0105	0.9895	81.26
29.5	329,365,571	3,059,498	0.0093	0.9907	80.40
30.5	302,955,630	2,466,111	0.0081	0.9919	79.66
31.5	363,863,653	3,964,515	0.0109	0.9891	79.01
32.5	358,028,935	1,764,860	0.0049	0.9951	78.15
33.5	238,534,731	873,288	0.0037	0.9963	77.76
34.5	210,542,217	766,406	0.0036	0.9964	77.48
35.5	145,012,400	2,539,641	0.0175	0.9825	77.20
36.5	131,635,520	1,405,679	0.0107	0.9893	75.84
37.5	77,236,617	453,560	0.0059	0.9941	75.03
38.5	69,454,950	622,220	0.0090	0.9910	74.59

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1952-2017 EXPERIENCE BAND 1952-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	66,714,895	1,866,440	0.0280	0.9720	73.93
40.5	82,786,523	885,562	0.0107	0.9893	71.86
41.5	64,352,766	238,846	0.0037	0.9963	71.09
42.5	46,664,686	236,847	0.0051	0.9949	70.82
43.5	46,472,660	464,722	0.0100	0.9900	70.47
44.5	45,776,591	91,243	0.0020	0.9980	69.76
45.5	23,628,143	24,448	0.0010	0.9990	69.62
46.5	13,741,476	122,993	0.0090	0.9910	69.55
47.5	13,514,219	5,147	0.0004	0.9996	68.93
48.5	13,045,421	8,777	0.0007	0.9993	68.90
49.5	7,581,647	52,002	0.0069	0.9931	68.85
50.5	7,572,305	279	0.0000	1.0000	68.38
51.5	7,572,026	785	0.0001	0.9999	68.38
52.5	7,571,240	6,004	0.0008	0.9992	68.37
53.5	1,511,128		0.0000	1.0000	68.32
54.5	1,495,372	561	0.0004	0.9996	68.32
55.5	1,494,811		0.0000	1.0000	68.29
56.5	1,494,811	1,471	0.0010	0.9990	68.29
57.5	985,103		0.0000	1.0000	68.23
58.5	985,103		0.0000	1.0000	68.23
59.5	865,017		0.0000	1.0000	68.23
60.5	865,017		0.0000	1.0000	68.23
61.5					68.23

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1952-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,342,384,105		0.0000	1.0000	100.00
0.5	2,539,836,114	480,091	0.0002	0.9998	100.00
1.5	2,282,939,329	455,315	0.0002	0.9998	99.98
2.5	1,848,098,592	2,763,663	0.0015	0.9985	99.96
3.5	1,457,222,565	7,959,487	0.0055	0.9945	99.81
4.5	1,510,194,596	2,428,865	0.0016	0.9984	99.27
5.5	1,490,372,937	23,108,720	0.0155	0.9845	99.11
6.5	1,288,359,669	8,180,300	0.0063	0.9937	97.57
7.5	1,267,598,995	7,357,353	0.0058	0.9942	96.95
8.5	1,270,068,031	15,869,461	0.0125	0.9875	96.39
9.5	1,234,179,031	3,312,061	0.0027	0.9973	95.18
10.5	1,243,527,076	9,948,030	0.0080	0.9920	94.93
11.5	1,092,532,426	17,011,795	0.0156	0.9844	94.17
12.5	1,117,288,154	6,703,994	0.0060	0.9940	92.70
13.5	1,077,746,565	5,844,741	0.0054	0.9946	92.15
14.5	962,717,703	10,444,170	0.0108	0.9892	91.65
15.5	911,185,667	10,037,467	0.0110	0.9890	90.65
16.5	829,695,245	3,228,593	0.0039	0.9961	89.65
17.5	780,310,791	1,806,544	0.0023	0.9977	89.30
18.5	757,829,447	3,012,855	0.0040	0.9960	89.10
19.5	664,068,002	9,035,445	0.0136	0.9864	88.74
20.5	646,762,999	9,775,743	0.0151	0.9849	87.54
21.5	627,052,202	6,826,696	0.0109	0.9891	86.21
22.5	606,263,511	3,438,644	0.0057	0.9943	85.27
23.5	602,322,517	9,729,864	0.0162	0.9838	84.79
24.5	622,207,323	2,383,499	0.0038	0.9962	83.42
25.5	598,330,614	3,101,829	0.0052	0.9948	83.10
26.5	591,734,975	3,738,271	0.0063	0.9937	82.67
27.5	384,218,954	6,351,743	0.0165	0.9835	82.15
28.5	349,603,011	3,670,672	0.0105	0.9895	80.79
29.5	329,325,571	3,059,498	0.0093	0.9907	79.94
30.5	302,955,630	2,466,111	0.0081	0.9919	79.20
31.5	363,863,653	3,964,515	0.0109	0.9891	78.55
32.5	358,028,935	1,764,860	0.0049	0.9951	77.70
33.5	238,534,731	873,288	0.0037	0.9963	77.32
34.5	210,542,217	766,406	0.0036	0.9964	77.03
35.5	145,012,400	2,539,641	0.0175	0.9825	76.75
36.5	131,635,520	1,405,679	0.0107	0.9893	75.41
37.5	77,236,617	453,560	0.0059	0.9941	74.60
38.5	69,454,950	622,220	0.0090	0.9910	74.16

LOUISVILLE GAS AND ELECTRIC COMPANY

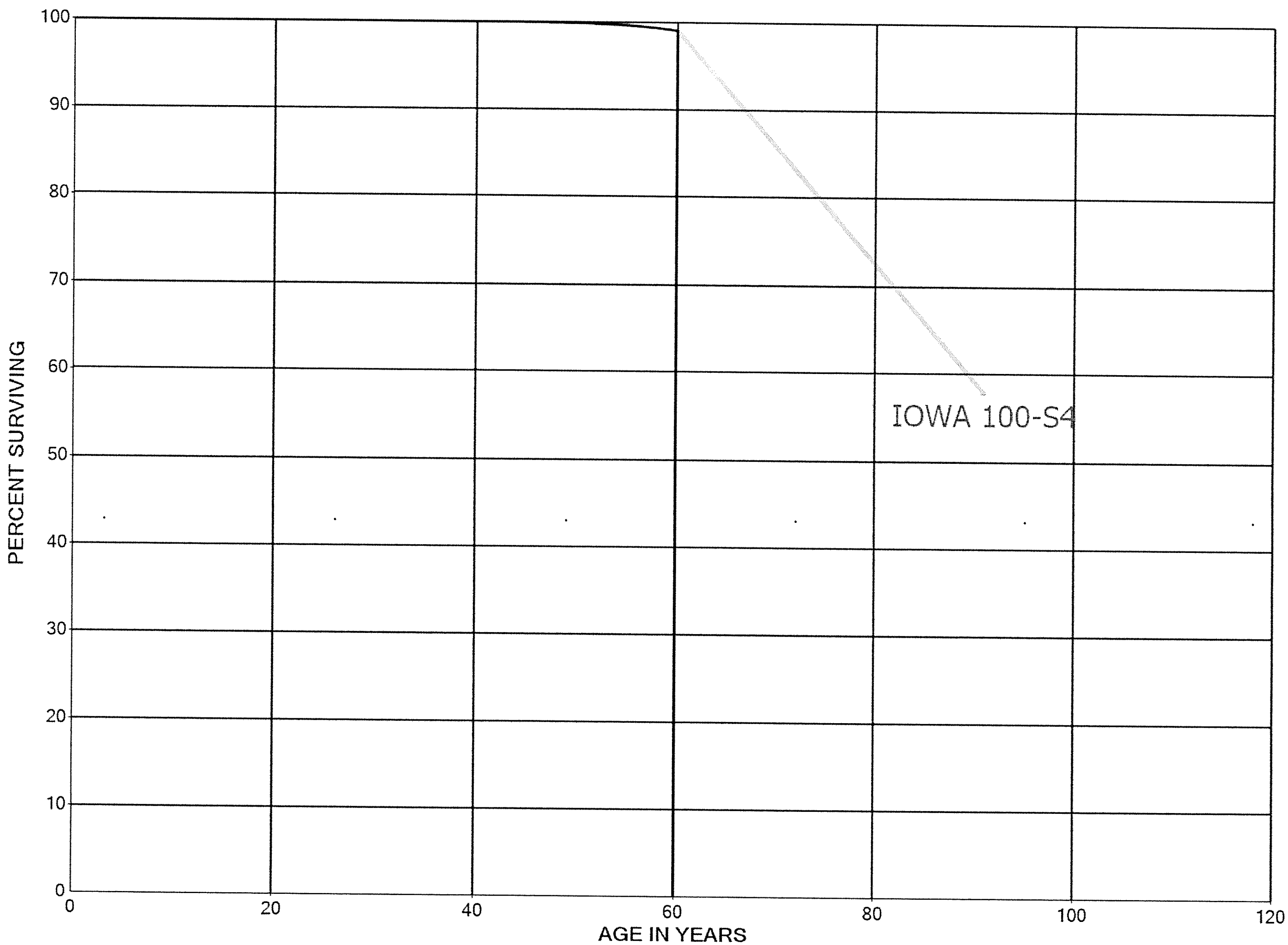
ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

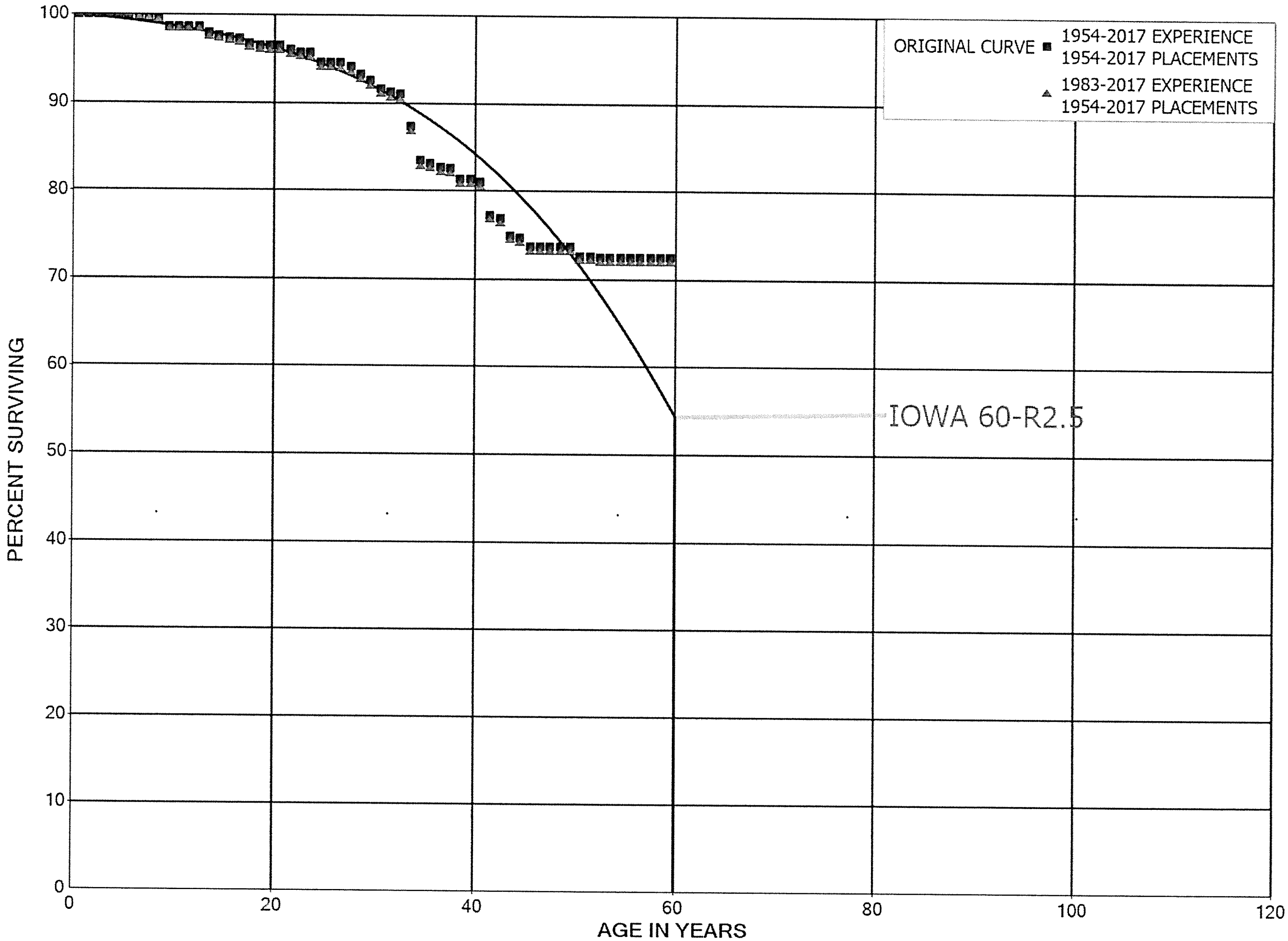
PLACEMENT BAND 1952-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	66,714,895	1,866,440	0.0280	0.9720	73.50
40.5	82,786,523	885,562	0.0107	0.9893	71.44
41.5	64,352,766	238,846	0.0037	0.9963	70.68
42.5	46,664,686	236,847	0.0051	0.9949	70.42
43.5	46,472,660	464,722	0.0100	0.9900	70.06
44.5	45,776,591	91,243	0.0020	0.9980	69.36
45.5	23,628,143	24,448	0.0010	0.9990	69.22
46.5	13,741,476	122,993	0.0090	0.9910	69.15
47.5	13,514,219	5,147	0.0004	0.9996	68.53
48.5	13,045,421	8,777	0.0007	0.9993	68.50
49.5	7,581,647	52,002	0.0069	0.9931	68.46
50.5	7,572,305	279	0.0000	1.0000	67.99
51.5	7,572,026	785	0.0001	0.9999	67.99
52.5	7,571,240	6,004	0.0008	0.9992	67.98
53.5	1,511,128		0.0000	1.0000	67.93
54.5	1,495,372	561	0.0004	0.9996	67.93
55.5	1,494,811		0.0000	1.0000	67.90
56.5	1,494,811	1,471	0.0010	0.9990	67.90
57.5	985,103		0.0000	1.0000	67.83
58.5	985,103		0.0000	1.0000	67.83
59.5	865,017		0.0000	1.0000	67.83
60.5	865,017		0.0000	1.0000	67.83
61.5					67.83

LOUISVILLE GAS AND ELECTRIC COMPANY
ACCOUNT 312.1 BOILER PLANT EQUIPMENT - ASH PONDS
SMOOTH SURVIVOR CURVE



LOUISVILLE GAS AND ELECTRIC COMPANY
ACCOUNT 314 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES



LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1954-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	324,465,122		0.0000	1.0000	100.00
0.5	321,442,753		0.0000	1.0000	100.00
1.5	320,172,085	80,613	0.0003	0.9997	100.00
2.5	302,346,521		0.0000	1.0000	99.97
3.5	285,207,567	7,908	0.0000	1.0000	99.97
4.5	275,038,355	81,235	0.0003	0.9997	99.97
5.5	263,816,397	649,485	0.0025	0.9975	99.94
6.5	239,302,171	239,951	0.0010	0.9990	99.70
7.5	225,390,056	276,808	0.0012	0.9988	99.60
8.5	238,942,165	2,084,160	0.0087	0.9913	99.47
9.5	232,416,743	9,300	0.0000	1.0000	98.61
10.5	216,941,493	12,000	0.0001	0.9999	98.60
11.5	214,968,633	26,735	0.0001	0.9999	98.60
12.5	207,738,776	1,447,108	0.0070	0.9930	98.58
13.5	205,143,229	563,930	0.0027	0.9973	97.90
14.5	202,356,885	416,559	0.0021	0.9979	97.63
15.5	199,378,557	376,332	0.0019	0.9981	97.43
16.5	196,906,452	975,050	0.0050	0.9950	97.24
17.5	195,843,641	463,230	0.0024	0.9976	96.76
18.5	173,523,090	77,984	0.0004	0.9996	96.53
19.5	166,929,977	27,206	0.0002	0.9998	96.49
20.5	164,758,392	764,781	0.0046	0.9954	96.47
21.5	166,497,687	429,680	0.0026	0.9974	96.03
22.5	166,234,970	143,253	0.0009	0.9991	95.78
23.5	166,531,081	1,846,543	0.0111	0.9889	95.70
24.5	160,365,696	21,006	0.0001	0.9999	94.64
25.5	159,361,227	74,875	0.0005	0.9995	94.62
26.5	157,013,646	698,722	0.0045	0.9955	94.58
27.5	112,990,044	989,623	0.0088	0.9912	94.16
28.5	111,965,622	925,378	0.0083	0.9917	93.33
29.5	107,064,910	1,044,725	0.0098	0.9902	92.56
30.5	105,922,634	455,230	0.0043	0.9957	91.66
31.5	128,848,366	277,652	0.0022	0.9978	91.26
32.5	128,039,838	5,159,144	0.0403	0.9597	91.07
33.5	89,284,970	4,030,531	0.0451	0.9549	87.40
34.5	85,241,172	253,886	0.0030	0.9970	83.45
35.5	66,460,996	365,931	0.0055	0.9945	83.20
36.5	57,742,285	97,824	0.0017	0.9983	82.75
37.5	44,695,374	667,693	0.0149	0.9851	82.61
38.5	44,027,084		0.0000	1.0000	81.37

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1954-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	41,730,465	163,243	0.0039	0.9961	81.37
40.5	51,543,789	2,365,992	0.0459	0.9541	81.05
41.5	40,191,354	219,895	0.0055	0.9945	77.33
42.5	29,949,592	758,365	0.0253	0.9747	76.91
43.5	28,052,309	97,844	0.0035	0.9965	74.96
44.5	27,897,125	377,326	0.0135	0.9865	74.70
45.5	17,954,759		0.0000	1.0000	73.69
46.5	11,406,916	2,639	0.0002	0.9998	73.69
47.5	11,404,278		0.0000	1.0000	73.67
48.5	11,403,622		0.0000	1.0000	73.67
49.5	6,081,646	84,973	0.0140	0.9860	73.67
50.5	6,039,903		0.0000	1.0000	72.64
51.5	6,038,207	14,204	0.0024	0.9976	72.64
52.5	6,010,646		0.0000	1.0000	72.47
53.5	686,900		0.0000	1.0000	72.47
54.5	686,900		0.0000	1.0000	72.47
55.5	686,900		0.0000	1.0000	72.47
56.5	686,900		0.0000	1.0000	72.47
57.5	119,080		0.0000	1.0000	72.47
58.5	119,080		0.0000	1.0000	72.47
59.5	105,161		0.0000	1.0000	72.47
60.5	105,161		0.0000	1.0000	72.47
61.5					72.47

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	206,231,210		0.0000	1.0000	100.00
0.5	238,780,231		0.0000	1.0000	100.00
1.5	237,561,182	80,613	0.0003	0.9997	100.00
2.5	219,736,293		0.0000	1.0000	99.97
3.5	212,517,674	7,393	0.0000	1.0000	99.97
4.5	217,298,623	80,885	0.0004	0.9996	99.96
5.5	206,138,930	647,208	0.0031	0.9969	99.93
6.5	181,632,394	236,900	0.0013	0.9987	99.61
7.5	167,886,886	271,634	0.0016	0.9984	99.48
8.5	195,225,857	2,064,160	0.0106	0.9894	99.32
9.5	188,752,140	5,000	0.0000	1.0000	98.27
10.5	184,794,813	12,000	0.0001	0.9999	98.27
11.5	182,879,293	24,908	0.0001	0.9999	98.26
12.5	175,671,545	1,446,525	0.0082	0.9918	98.25
13.5	181,255,481	563,930	0.0031	0.9969	97.44
14.5	178,469,137	403,559	0.0023	0.9977	97.14
15.5	175,510,366	376,332	0.0021	0.9979	96.92
16.5	178,677,070	975,050	0.0055	0.9945	96.71
17.5	177,777,699	463,230	0.0026	0.9974	96.18
18.5	155,459,561	77,984	0.0005	0.9995	95.93
19.5	148,880,109	24,446	0.0002	0.9998	95.88
20.5	152,424,605	764,781	0.0050	0.9950	95.87
21.5	154,163,900	414,680	0.0027	0.9973	95.39
22.5	153,955,417	143,253	0.0009	0.9991	95.13
23.5	154,251,528	1,843,230	0.0119	0.9881	95.04
24.5	152,874,000	21,006	0.0001	0.9999	93.90
25.5	151,869,531	66,171	0.0004	0.9996	93.89
26.5	153,365,215	698,722	0.0046	0.9954	93.85
27.5	109,341,613	989,623	0.0091	0.9909	93.42
28.5	111,965,622	925,378	0.0083	0.9917	92.58
29.5	107,064,910	1,044,725	0.0098	0.9902	91.81
30.5	105,922,634	455,230	0.0043	0.9957	90.92
31.5	128,848,366	277,652	0.0022	0.9978	90.53
32.5	128,039,838	5,159,144	0.0403	0.9597	90.33
33.5	89,284,970	4,030,531	0.0451	0.9549	86.69
34.5	85,241,172	253,886	0.0030	0.9970	82.78
35.5	66,460,996	365,931	0.0055	0.9945	82.53
36.5	57,742,285	97,824	0.0017	0.9983	82.08
37.5	44,695,374	667,693	0.0149	0.9851	81.94
38.5	44,027,084		0.0000	1.0000	80.71

LOUISVILLE GAS AND ELECTRIC COMPANY

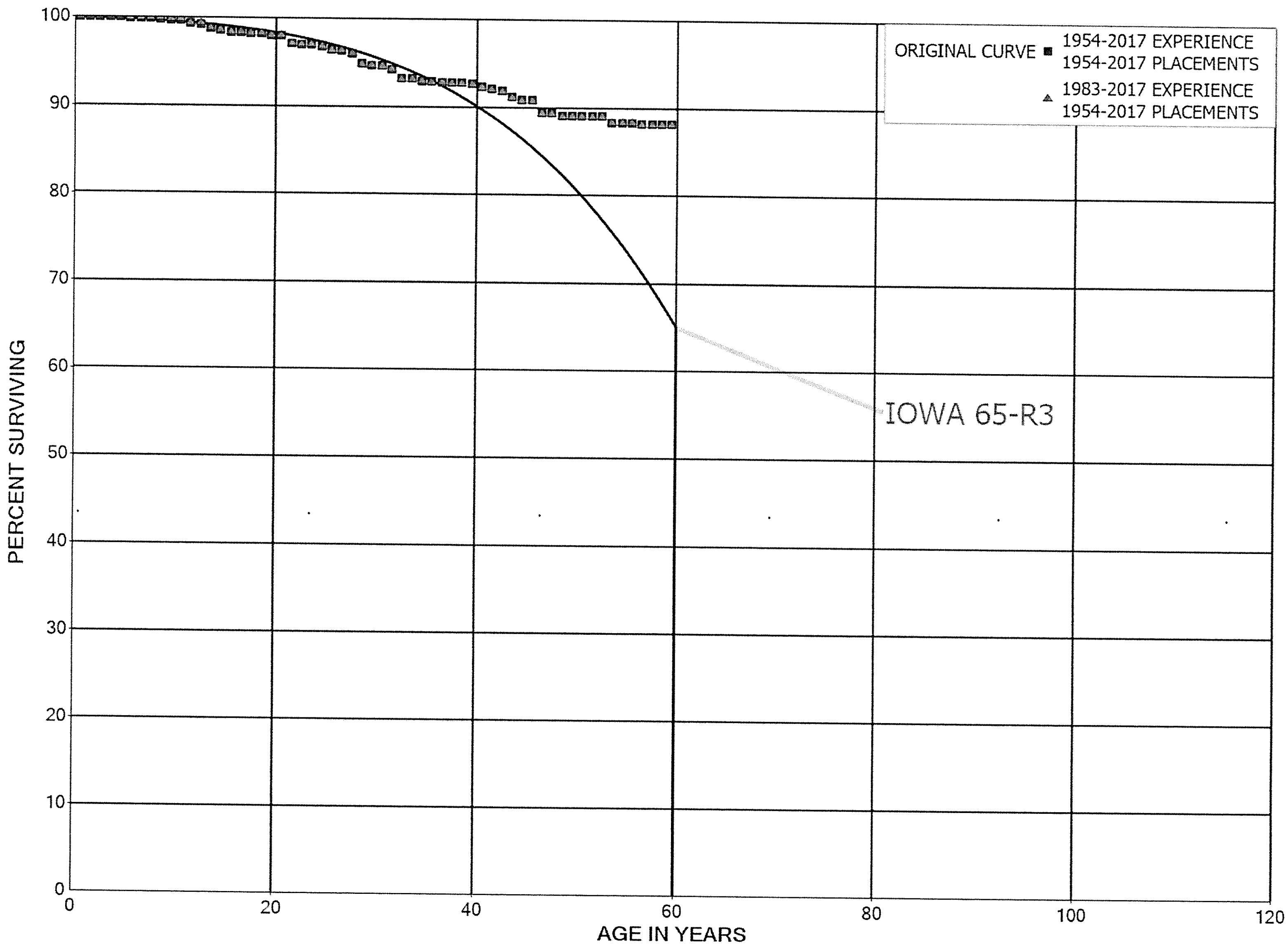
ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	41,730,465	163,243	0.0039	0.9961	80.71
40.5	51,543,789	2,365,992	0.0459	0.9541	80.40
41.5	40,191,354	219,895	0.0055	0.9945	76.71
42.5	29,949,592	758,365	0.0253	0.9747	76.29
43.5	28,052,309	97,844	0.0035	0.9965	74.36
44.5	27,897,125	377,326	0.0135	0.9865	74.10
45.5	17,954,759		0.0000	1.0000	73.09
46.5	11,406,916	2,639	0.0002	0.9998	73.09
47.5	11,404,278		0.0000	1.0000	73.08
48.5	11,403,622		0.0000	1.0000	73.08
49.5	6,081,646	84,973	0.0140	0.9860	73.08
50.5	6,039,903		0.0000	1.0000	72.06
51.5	6,038,207	14,204	0.0024	0.9976	72.06
52.5	6,010,646		0.0000	1.0000	71.89
53.5	686,900		0.0000	1.0000	71.89
54.5	686,900		0.0000	1.0000	71.89
55.5	686,900		0.0000	1.0000	71.89
56.5	686,900		0.0000	1.0000	71.89
57.5	119,080		0.0000	1.0000	71.89
58.5	119,080		0.0000	1.0000	71.89
59.5	105,161		0.0000	1.0000	71.89
60.5	105,161		0.0000	1.0000	71.89
61.5					71.89

LOUISVILLE GAS AND ELECTRIC COMPANY
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1954-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	244,804,240		0.0000	1.0000	100.00
0.5	242,771,960	298	0.0000	1.0000	100.00
1.5	217,683,499	2,203	0.0000	1.0000	100.00
2.5	191,841,217	45,128	0.0002	0.9998	100.00
3.5	184,708,738	146,910	0.0008	0.9992	99.98
4.5	184,949,470	35,225	0.0002	0.9998	99.90
5.5	182,179,576	110,294	0.0006	0.9994	99.88
6.5	171,553,573	33,426	0.0002	0.9998	99.82
7.5	171,827,575	76,726	0.0004	0.9996	99.80
8.5	171,110,027	155,507	0.0009	0.9991	99.75
9.5	172,040,461	25,524	0.0001	0.9999	99.66
10.5	171,753,134	627,461	0.0037	0.9963	99.65
11.5	170,885,459	142,581	0.0008	0.9992	99.28
12.5	170,486,420	743,699	0.0044	0.9956	99.20
13.5	170,635,690	385,262	0.0023	0.9977	98.77
14.5	170,403,883	403,792	0.0024	0.9976	98.54
15.5	171,152,648	101,392	0.0006	0.9994	98.31
16.5	170,423,057	174,686	0.0010	0.9990	98.25
17.5	159,832,153	31,390	0.0002	0.9998	98.15
18.5	150,234,924	261,684	0.0017	0.9983	98.13
19.5	137,075,168	22,428	0.0002	0.9998	97.96
20.5	134,267,805	1,139,752	0.0085	0.9915	97.95
21.5	133,153,573	160,604	0.0012	0.9988	97.11
22.5	132,157,715	70,910	0.0005	0.9995	97.00
23.5	127,622,354	299,331	0.0023	0.9977	96.94
24.5	126,114,214	463,342	0.0037	0.9963	96.72
25.5	126,648,924	38,689	0.0003	0.9997	96.36
26.5	127,266,160	479,074	0.0038	0.9962	96.33
27.5	80,142,525	922,930	0.0115	0.9885	95.97
28.5	79,408,524	180,618	0.0023	0.9977	94.86
29.5	79,548,168	15,097	0.0002	0.9998	94.65
30.5	79,392,955	350,347	0.0044	0.9956	94.63
31.5	93,392,413	1,030,494	0.0110	0.9890	94.21
32.5	91,838,075	48,886	0.0005	0.9995	93.17
33.5	67,761,230	174,945	0.0026	0.9974	93.12
34.5	60,041,813	49,609	0.0008	0.9992	92.88
35.5	39,249,588	13,132	0.0003	0.9997	92.81
36.5	35,407,211	23,441	0.0007	0.9993	92.78
37.5	21,803,473		0.0000	1.0000	92.71
38.5	20,568,393	19,693	0.0010	0.9990	92.71

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1954-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	19,583,717	67,907	0.0035	0.9965	92.63
40.5	23,157,622	61,581	0.0027	0.9973	92.30
41.5	19,331,225	54,105	0.0028	0.9972	92.06
42.5	13,893,773	91,521	0.0066	0.9934	91.80
43.5	13,197,572	50,739	0.0038	0.9962	91.20
44.5	13,135,696	4,700	0.0004	0.9996	90.85
45.5	8,766,294	142,139	0.0162	0.9838	90.81
46.5	6,853,073		0.0000	1.0000	89.34
47.5	6,826,685	24,111	0.0035	0.9965	89.34
48.5	6,507,783	14	0.0000	1.0000	89.03
49.5	5,361,890	784	0.0001	0.9999	89.03
50.5	5,351,626		0.0000	1.0000	89.01
51.5	5,019,222		0.0000	1.0000	89.01
52.5	5,017,566	39,155	0.0078	0.9922	89.01
53.5	3,779,505		0.0000	1.0000	88.32
54.5	3,778,777		0.0000	1.0000	88.32
55.5	3,777,980	7,356	0.0019	0.9981	88.32
56.5	3,770,124		0.0000	1.0000	88.15
57.5	3,010,822		0.0000	1.0000	88.15
58.5	3,010,307		0.0000	1.0000	88.15
59.5	1,777,553		0.0000	1.0000	88.15
60.5	1,776,132		0.0000	1.0000	88.15
61.5					88.15

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	168,711,841		0.0000	1.0000	100.00
0.5	188,887,780		0.0000	1.0000	100.00
1.5	171,029,352		0.0000	1.0000	100.00
2.5	152,292,152	9,990	0.0001	0.9999	100.00
3.5	145,411,691	139,025	0.0010	0.9990	99.99
4.5	159,452,943	26,346	0.0002	0.9998	99.90
5.5	157,948,762	48,969	0.0003	0.9997	99.88
6.5	148,972,884	32,001	0.0002	0.9998	99.85
7.5	149,733,580	8,046	0.0001	0.9999	99.83
8.5	153,989,438	152,241	0.0010	0.9990	99.82
9.5	155,168,564	22,970	0.0001	0.9999	99.72
10.5	160,756,184	623,978	0.0039	0.9961	99.71
11.5	159,903,130	138,751	0.0009	0.9991	99.32
12.5	159,530,922	743,699	0.0047	0.9953	99.24
13.5	162,225,403	385,262	0.0024	0.9976	98.77
14.5	162,067,467	401,852	0.0025	0.9975	98.54
15.5	163,161,950	96,947	0.0006	0.9994	98.30
16.5	164,008,960	172,466	0.0011	0.9989	98.24
17.5	153,431,168	11,418	0.0001	0.9999	98.13
18.5	143,885,967	239,303	0.0017	0.9983	98.13
19.5	130,750,248	17,890	0.0001	0.9999	97.96
20.5	129,182,497	1,129,337	0.0087	0.9913	97.95
21.5	128,085,352	160,604	0.0013	0.9987	97.09
22.5	127,118,785	70,910	0.0006	0.9994	96.97
23.5	122,583,923	299,331	0.0024	0.9976	96.92
24.5	122,064,097	463,342	0.0038	0.9962	96.68
25.5	122,599,321	38,689	0.0003	0.9997	96.31
26.5	125,010,393	479,074	0.0038	0.9962	96.28
27.5	77,888,179	922,686	0.0118	0.9882	95.91
28.5	79,408,524	180,618	0.0023	0.9977	94.78
29.5	79,548,168	15,097	0.0002	0.9998	94.56
30.5	79,392,955	350,347	0.0044	0.9956	94.54
31.5	93,392,413	1,030,494	0.0110	0.9890	94.13
32.5	91,838,075	48,886	0.0005	0.9995	93.09
33.5	67,761,230	174,945	0.0026	0.9974	93.04
34.5	60,041,813	49,609	0.0008	0.9992	92.80
35.5	39,249,588	13,132	0.0003	0.9997	92.72
36.5	35,407,211	23,441	0.0007	0.9993	92.69
37.5	21,803,473		0.0000	1.0000	92.63
38.5	20,568,393	19,693	0.0010	0.9990	92.63

LOUISVILLE GAS AND ELECTRIC COMPANY

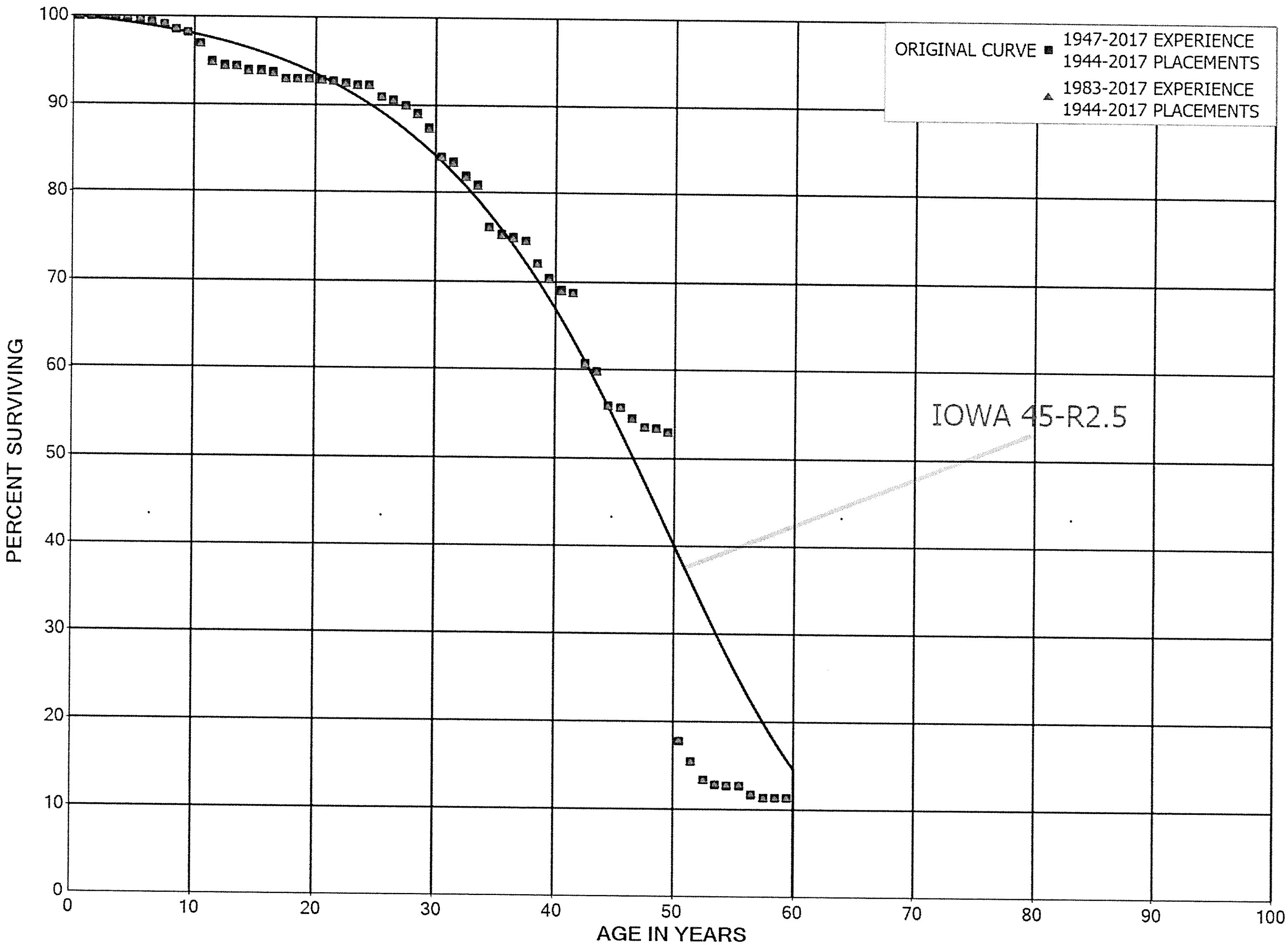
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	19,583,717	67,907	0.0035	0.9965	92.54
40.5	23,157,622	61,581	0.0027	0.9973	92.22
41.5	19,331,225	54,105	0.0028	0.9972	91.98
42.5	13,893,773	91,521	0.0066	0.9934	91.72
43.5	13,197,572	50,739	0.0038	0.9962	91.11
44.5	13,135,696	4,700	0.0004	0.9996	90.76
45.5	8,766,294	142,139	0.0162	0.9838	90.73
46.5	6,853,073		0.0000	1.0000	89.26
47.5	6,826,685	24,111	0.0035	0.9965	89.26
48.5	6,507,783	14	0.0000	1.0000	88.94
49.5	5,361,890	784	0.0001	0.9999	88.94
50.5	5,351,626		0.0000	1.0000	88.93
51.5	5,019,222		0.0000	1.0000	88.93
52.5	5,017,566	39,155	0.0078	0.9922	88.93
53.5	3,779,505		0.0000	1.0000	88.24
54.5	3,778,777		0.0000	1.0000	88.24
55.5	3,777,980	7,356	0.0019	0.9981	88.24
56.5	3,770,124		0.0000	1.0000	88.07
57.5	3,010,822		0.0000	1.0000	88.07
58.5	3,010,307		0.0000	1.0000	88.07
59.5	1,777,553		0.0000	1.0000	88.07
60.5	1,776,132		0.0000	1.0000	88.07
61.5					88.07

LOUISVILLE GAS AND ELECTRIC COMPANY
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1944-2017 EXPERIENCE BAND 1947-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,606,433		0.0000	1.0000	100.00
0.5	23,449,651	677	0.0000	1.0000	100.00
1.5	22,742,532	2,120	0.0001	0.9999	100.00
2.5	22,033,998	8,003	0.0004	0.9996	99.99
3.5	19,689,372	16,984	0.0009	0.9991	99.95
4.5	18,199,357	53,501	0.0029	0.9971	99.87
5.5	17,943,293	47,151	0.0026	0.9974	99.57
6.5	15,301,466	36,381	0.0024	0.9976	99.31
7.5	14,236,241	78,162	0.0055	0.9945	99.07
8.5	13,526,831	42,779	0.0032	0.9968	98.53
9.5	13,114,929	171,050	0.0130	0.9870	98.22
10.5	12,199,852	250,426	0.0205	0.9795	96.94
11.5	11,162,508	49,169	0.0044	0.9956	94.95
12.5	11,021,319	10,549	0.0010	0.9990	94.53
13.5	11,033,378	59,572	0.0054	0.9946	94.44
14.5	10,178,590	1,701	0.0002	0.9998	93.93
15.5	9,716,552	21,657	0.0022	0.9978	93.91
16.5	9,220,848	70,908	0.0077	0.9923	93.70
17.5	8,846,541	2,730	0.0003	0.9997	92.98
18.5	8,097,719	1,595	0.0002	0.9998	92.95
19.5	7,805,381	9,507	0.0012	0.9988	92.94
20.5	7,495,233	5,560	0.0007	0.9993	92.82
21.5	7,142,077	21,184	0.0030	0.9970	92.75
22.5	6,669,099	11,649	0.0017	0.9983	92.48
23.5	6,304,898	1	0.0000	1.0000	92.32
24.5	5,950,420	85,520	0.0144	0.9856	92.32
25.5	5,627,219	22,195	0.0039	0.9961	90.99
26.5	4,600,598	31,595	0.0069	0.9931	90.63
27.5	2,785,994	28,437	0.0102	0.9898	90.01
28.5	2,644,496	49,674	0.0188	0.9812	89.09
29.5	2,436,080	92,039	0.0378	0.9622	87.42
30.5	2,199,934	16,848	0.0077	0.9923	84.11
31.5	1,940,772	35,692	0.0184	0.9816	83.47
32.5	1,836,909	22,609	0.0123	0.9877	81.94
33.5	1,648,336	96,562	0.0586	0.9414	80.93
34.5	1,427,499	15,297	0.0107	0.9893	76.19
35.5	1,381,445	5,601	0.0041	0.9959	75.37
36.5	1,309,084	7,097	0.0054	0.9946	75.06
37.5	1,256,915	42,800	0.0341	0.9659	74.66
38.5	1,176,347	28,818	0.0245	0.9755	72.11

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1944-2017 EXPERIENCE BAND 1947-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	898,521	16,823	0.0187	0.9813	70.35
40.5	846,796	3,802	0.0045	0.9955	69.03
41.5	801,188	93,212	0.1163	0.8837	68.72
42.5	679,520	9,738	0.0143	0.9857	60.73
43.5	633,248	40,974	0.0647	0.9353	59.86
44.5	522,935	1,904	0.0036	0.9964	55.98
45.5	195,523	4,501	0.0230	0.9770	55.78
46.5	190,353	3,272	0.0172	0.9828	54.49
47.5	187,081	485	0.0026	0.9974	53.56
48.5	186,596	1,799	0.0096	0.9904	53.42
49.5	184,798	122,826	0.6647	0.3353	52.90
50.5	61,972	8,187	0.1321	0.8679	17.74
51.5	53,784	7,531	0.1400	0.8600	15.40
52.5	46,254	1,724	0.0373	0.9627	13.24
53.5	44,530	323	0.0073	0.9927	12.75
54.5	44,207		0.0000	1.0000	12.66
55.5	43,278	3,518	0.0813	0.9187	12.66
56.5	39,760	1,288	0.0324	0.9676	11.63
57.5	38,472		0.0000	1.0000	11.25
58.5	38,270		0.0000	1.0000	11.25
59.5	37,214		0.0000	1.0000	11.25
60.5	29,806		0.0000	1.0000	11.25
61.5	29,104		0.0000	1.0000	11.25
62.5	28,982		0.0000	1.0000	11.25
63.5	28,982		0.0000	1.0000	11.25
64.5	28,871		0.0000	1.0000	11.25
65.5	20,131		0.0000	1.0000	11.25
66.5	3,223		0.0000	1.0000	11.25
67.5	1,634		0.0000	1.0000	11.25
68.5	277		0.0000	1.0000	11.25
69.5	277		0.0000	1.0000	11.25
70.5	277		0.0000	1.0000	11.25
71.5					11.25

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1944-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	23,110,214		0.0000	1.0000	100.00
0.5	21,401,848		0.0000	1.0000	100.00
1.5	20,889,711		0.0000	1.0000	100.00
2.5	20,273,809	7,218	0.0004	0.9996	100.00
3.5	17,987,979	16,306	0.0009	0.9991	99.96
4.5	16,793,057	51,430	0.0031	0.9969	99.87
5.5	16,588,877	45,894	0.0028	0.9972	99.57
6.5	13,956,939	32,962	0.0024	0.9976	99.29
7.5	12,916,752	75,236	0.0058	0.9942	99.06
8.5	12,282,707	39,234	0.0032	0.9968	98.48
9.5	11,980,818	170,665	0.0142	0.9858	98.17
10.5	11,486,714	250,426	0.0218	0.9782	96.77
11.5	10,492,850	49,169	0.0047	0.9953	94.66
12.5	10,377,627	10,199	0.0010	0.9990	94.21
13.5	10,413,326	53,523	0.0051	0.9949	94.12
14.5	9,584,186	1,701	0.0002	0.9998	93.64
15.5	9,160,044	21,106	0.0023	0.9977	93.62
16.5	8,770,665	64,901	0.0074	0.9926	93.41
17.5	8,404,157		0.0000	1.0000	92.71
18.5	7,674,439	624	0.0001	0.9999	92.71
19.5	7,392,279	9,255	0.0013	0.9987	92.71
20.5	7,154,137	5,560	0.0008	0.9992	92.59
21.5	6,806,689	21,184	0.0031	0.9969	92.52
22.5	6,336,670	11,649	0.0018	0.9982	92.23
23.5	5,972,999	1	0.0000	1.0000	92.06
24.5	5,664,417	78,020	0.0138	0.9862	92.06
25.5	5,348,716	22,195	0.0041	0.9959	90.79
26.5	4,342,198	31,595	0.0073	0.9927	90.42
27.5	2,528,162	28,437	0.0112	0.9888	89.76
28.5	2,644,296	49,674	0.0188	0.9812	88.75
29.5	2,435,880	92,039	0.0378	0.9622	87.08
30.5	2,199,734	16,848	0.0077	0.9923	83.79
31.5	1,940,572	35,692	0.0184	0.9816	83.15
32.5	1,836,709	22,609	0.0123	0.9877	81.62
33.5	1,648,136	96,562	0.0586	0.9414	80.62
34.5	1,427,299	15,297	0.0107	0.9893	75.89
35.5	1,381,445	5,601	0.0041	0.9959	75.08
36.5	1,309,084	7,097	0.0054	0.9946	74.78
37.5	1,256,915	42,800	0.0341	0.9659	74.37
38.5	1,176,347	28,818	0.0245	0.9755	71.84

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1944-2017 EXPERIENCE BAND 1983-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	898,521	16,823	0.0187	0.9813	70.08
40.5	846,796	3,802	0.0045	0.9955	68.77
41.5	801,188	93,212	0.1163	0.8837	68.46
42.5	679,520	9,738	0.0143	0.9857	60.49
43.5	633,248	40,974	0.0647	0.9353	59.63
44.5	522,935	1,904	0.0036	0.9964	55.77
45.5	195,523	4,501	0.0230	0.9770	55.56
46.5	190,353	3,272	0.0172	0.9828	54.29
47.5	187,081	485	0.0026	0.9974	53.35
48.5	186,596	1,799	0.0096	0.9904	53.21
49.5	184,798	122,826	0.6647	0.3353	52.70
50.5	61,972	8,187	0.1321	0.8679	17.67
51.5	53,784	7,531	0.1400	0.8600	15.34
52.5	46,254	1,724	0.0373	0.9627	13.19
53.5	44,530	323	0.0073	0.9927	12.70
54.5	44,207		0.0000	1.0000	12.61
55.5	43,278	3,518	0.0813	0.9187	12.61
56.5	39,760	1,288	0.0324	0.9676	11.58
57.5	38,472		0.0000	1.0000	11.21
58.5	38,270		0.0000	1.0000	11.21
59.5	37,214		0.0000	1.0000	11.21
60.5	29,806		0.0000	1.0000	11.21
61.5	29,104		0.0000	1.0000	11.21
62.5	28,982		0.0000	1.0000	11.21
63.5	28,982		0.0000	1.0000	11.21
64.5	28,871		0.0000	1.0000	11.21
65.5	20,131		0.0000	1.0000	11.21
66.5	3,223		0.0000	1.0000	11.21
67.5	1,634		0.0000	1.0000	11.21
68.5	277		0.0000	1.0000	11.21
69.5	277		0.0000	1.0000	11.21
70.5	277		0.0000	1.0000	11.21
71.5					11.21

PART VIII. NET SALVAGE STATISTICS

LOUISVILLE GAS AND ELECTRIC COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2017

	Account	Terminal Retirements: Retirements ($)	Terminal Retirements: Net Salvage ($)	Net Salvage (%)	Interim Retirements: Retirements ($)	Interim Retirements: Net Salvage (%)	Interim Retirements: Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
	(1)	(2)	(3)	(4)=(3)/(2)	(5)	(6)	(7)=(5)x(6)	(8)=(3)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	STEAM PRODUCTION PLANT									
	CANE RUN GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	16,811,037	(1,681,104)	(10)	-	(25)	-	(1,681,103.73)	16,811,037	(10)
312	BOILER PLANT EQUIPMENT	5,944,973	(594,497)	(10)	-	(25)	-	(594,497)	5,944,973	(10)
314	TURBOGENERATOR UNITS	1,180,444	(118,044)	(10)	-	(15)	-	(118,044)	1,180,444	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	1,121	(112)	(10)	-	(15)	-	(112)	1,121	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	608,122	(60,812)	(10)	-	(2)	-	(60,812)	608,122	(10)
	TOTAL CANE RUN GENERATING STATION	*24,545,697*	*(2,454,570)*		-		-	*(2,454,570)*	*24,545,697*	*(10)*
	MILL CREEK GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	144,777,504	(11,582,200)	(8)	9,277,313	(25)	(2,319,328)	(13,901,529)	154,054,818	(10)
312	BOILER PLANT EQUIPMENT	1,378,299,563	(110,263,965)	(8)	239,745,823	(25)	(59,936,456)	(170,200,421)	1,618,045,386	(10)
314	TURBOGENERATOR UNITS	118,161,189	(9,452,895)	(8)	26,003,466	(15)	(3,900,520)	(13,353,415)	144,164,655	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	86,416,422	(6,913,314)	(8)	17,463,081	(15)	(2,619,462)	(9,532,775.97)	103,879,503	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	9,739,999	(779,200)	(8)	2,764,180	(2)	(55,284)	(834,483)	12,504,178	(10)
	TOTAL MILL CREEK GENERATING STATION	*1,737,394,677*	*(138,991,574)*		*295,253,863*		*(68,831,050)*	*(207,822,624)*	*2,032,648,540*	*(10)*
	TRIMBLE COUNTY GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	112,342,178	(10,110,796)	(9)	13,517,241	(25)	(3,379,310)	(13,490,106)	125,859,419	(14)
312	BOILER PLANT EQUIPMENT	340,306,097	(30,627,549)	(9)	211,049,263	(25)	(52,762,316)	(83,389,865)	551,355,361	(14)
314	TURBOGENERATOR UNITS	52,942,160	(4,764,794)	(9)	28,562,435	(15)	(4,284,365)	(9,049,160)	81,504,595	(14)
315	ACCESSORY ELECTRIC EQUIPMENT	52,876,881	(4,758,919)	(9)	25,637,979	(15)	(3,845,697)	(8,604,616)	78,514,860	(14)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	3,151,292	(283,616)	(9)	3,471,164	(2)	(69,423)	(353,040)	6,622,456	(14)
	TOTAL TRIMBLE COUNTY GENERATING STATION	*561,618,609*	*(50,545,675)*		*282,238,082*		*(64,341,112)*	*(114,886,786)*	*843,856,691*	*(14)*
	TOTAL STEAM PRODUCTION PLANT	**2,323,558,983**	**(191,991,819)**		**577,491,945**		**(133,172,161)**	**(325,163,980)**	**2,901,050,928**	

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1972	5,380	162	3		0	162-	3-
1973	9,301		0	775	8	775	8
1974	166,455	30,008	18	552	0	29,456-	18-
1975	4,816	2,201	46		0	2,201-	46-
1976	17,364	2,461	14	148	1	2,313-	13-
1977	9,993	3,390	34		0	3,390-	34-
1978	706		0		0		0
1979	35,088	9,102	26	1,550	4	7,552-	22-
1980	4,245		0		0		0
1981	336,223	1,656	0		0	1,656-	0
1982	3,566	335	9		0	335-	9-
1983	527,107	734	0	11	0	723-	0
1984	7,999,955	139,134	2		0	139,134-	2-
1985	27,301	57,960	212		0	57,960-	212-
1986	83,061	29,750	36	10,787	13	18,963-	23-
1987	125,887	20,183	16	69	0	20,114-	16-
1988	19,638		0		0		0
1989	4,499		0		0		0
1990							
1991	67,462	17,694	26		0	17,694-	26-
1992	141,612	1,588	1		0	1,588-	1-
1993	279,758	44,837	16		0	44,837-	16-
1994	52,490		0		0		0
1995	258,855	21,373	8	1,279	0	20,094-	8-
1996	135,288	54,185	40	6,329	5	47,856-	35-
1997	70,532	8,504	12	8,625	12	121	0
1998	448,015	207,901	46		0	207,901-	46-
1999	110,093	36,068	33	697	1	35,371-	32-
2000	40,964		0		0		0
2001	171,276	990	1		0	990-	1-
2002	111,468		0		0		0
2003	865,133	100,649	12		0	100,649-	12-
2004	629,199	260,812	41		0	260,812-	41-
2005	921,450	114,744	12		0	114,744-	12-
2006	697,724	278,680	40		0	278,680-	40-
2007	78,460	3,894	5		0	3,894-	5-
2008	81,616	16,027	20		0	16,027-	20-
2009	484,516	172,070	36		0	172,070-	36-
2010	176,038	90,160	51		0	90,160-	51-
2011	4,196,980	1,255,579	30		0	1,255,579-	30-
2012	346,525	407,133	117		0	407,133-	117-
2013	524,191	840,164	160	398	0	839,766-	160-
2014	639,283	480,834	75		0	480,834-	75-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2015	849,133	418,910	49		0	418,910-	49-
2016	533,975	80,996	15		0	80,996-	15-
2017	209,322	68,731	33		0	68,731-	33-
TOTAL	22,501,944	5,279,598	23	31,220	0	5,248,378-	23-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
72-74	60,379	10,057	17	442	1	9,614-	16-
73-75	60,191	10,736	18	442	1	10,294-	17-
74-76	62,878	11,557	18	233	0	11,323-	18-
75-77	10,724	2,684	25	49	0	2,635-	25-
76-78	9,354	1,950	21	49	1	1,901-	20-
77-79	15,262	4,164	27	517	3	3,647-	24-
78-80	13,346	3,034	23	517	4	2,517-	19-
79-81	125,185	3,586	3	517	0	3,069-	2-
80-82	114,678	664	1		0	664-	1-
81-83	288,965	908	0	4	0	905-	0
82-84	2,843,543	46,734	2	4	0	46,731-	2-
83-85	2,851,454	65,943	2	4	0	65,939-	2-
84-86	2,703,439	75,615	3	3,596	0	72,019-	3-
85-87	78,750	35,964	46	3,619	5	32,346-	41-
86-88	76,195	16,644	22	3,619	5	13,026-	17-
87-89	50,008	6,728	13	23	0	6,705-	13-
88-90	8,046		0		0		0
89-91	23,987	5,898	25		0	5,898-	25-
90-92	69,691	6,427	9		0	6,427-	9-
91-93	162,944	21,373	13		0	21,373-	13-
92-94	157,953	15,475	10		0	15,475-	10-
93-95	197,034	22,070	11	426	0	21,644-	11-
94-96	148,878	25,186	17	2,536	2	22,650-	15-
95-97	154,892	28,021	18	5,411	3	22,610-	15-
96-98	217,945	90,197	41	4,985	2	85,212-	39-
97-99	209,547	84,158	40	3,107	1	81,050-	39-
98-00	199,691	81,323	41	232	0	81,091-	41-
99-01	107,444	12,353	11	232	0	12,120-	11-
00-02	107,903	330	0		0	330-	0
01-03	382,626	33,880	9		0	33,880-	9-
02-04	535,267	120,487	23		0	120,487-	23-
03-05	805,261	158,735	20		0	158,735-	20-
04-06	749,457	218,078	29		0	218,078-	29-
05-07	565,878	132,439	23		0	132,439-	23-
06-08	285,933	99,533	35		0	99,533-	35-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
07-09	214,864	63,997	30		0	63,997-	30-
08-10	247,390	92,752	37		0	92,752-	37-
09-11	1,619,178	505,937	31		0	505,937-	31-
10-12	1,573,181	584,291	37		0	584,291-	37-
11-13	1,689,232	834,292	49	133	0	834,159-	49-
12-14	503,333	576,044	114	133	0	575,911-	114-
13-15	670,869	579,970	86	133	0	579,837-	86-
14-16	674,130	326,914	48		0	326,914-	48-
15-17	530,810	189,546	36		0	189,546-	36-
FIVE-YEAR AVERAGE							
13-17	551,181	377,927	69	80	0	377,847-	69-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1973	62,803	4,171	7	648	1	3,523-	6-
1974	7,673	6,835	89	12	0	6,823-	89-
1975	3,085	402	13	383	12	19-	1-
1976	3,221		0		0		0
1977	326,169	62,640	19	5,757	2	56,883-	17-
1978	194,645	243	0	2,078	1	1,835	1
1979	2,069,174	10,000	0		0	10,000-	0
1980	553,764	39,529	7	5,000	1	34,529-	6-
1981	5,642,246	130,545	2		0	130,545-	2-
1982	1,289,749	35,582	3		0	35,582-	3-
1983	2,872,642	34,486	1	10,535	0	23,951-	1-
1984	19,009,765	1,405,123	7	25,077	0	1,380,046-	7-
1985	11,336,125	1,868,829	16	24,791	0	1,844,038-	16-
1986	4,583,696	2,041,987	45	23,452	1	2,018,535-	44-
1987	5,711,646	882,146	15	7,564	0	874,582-	15-
1988	981,609	220,046	22	84-	0	220,130-	22-
1989	1,150,890	29,619	3		0	29,619-	3-
1990	274,896	45,528	17		0	45,528-	17-
1991	514,723	1,963	0		0	1,963-	0
1992	657,502	37,558-	6-		0	37,558	6
1993	727,737	130,969-	18-	8,692	1	139,661	19
1994	518,558	102,303	20	4,250	1	98,053-	19-
1995	8,391,354	687,291	8	41,471	0	645,820-	8-
1996	2,043,488	614,554	30	95,593	5	518,961-	25-
1997	1,563,889	188,562	12	191,250	12	2,688	0
1998	2,744,038	1,273,372	46		0	1,273,372-	46-
1999	6,407,359	2,121,390	33	41,005	1	2,080,385-	32-
2000	1,939,284	549,421	28	319,613	16	229,808-	12-
2001	8,057,111	330,086	4		0	330,086-	4-
2002	5,505,871	495,797	9		0	495,797-	9-
2003	7,090,285	9,195	0		0	9,195-	0
2004	6,901,489	1,994,239	29		0	1,994,239-	29-
2005	4,197,701	1,079,108	26		0	1,079,108-	26-
2006	27,711,972	10,223,501	37	577,580	2	9,645,921-	35-
2007	3,095,537	815,490	26	281,090	9	534,400-	17-
2008	3,796,631	1,500,760	40	86,662	2	1,414,098-	37-
2009	7,012,615	3,053,175	44	27,191	0	3,025,984-	43-
2010	3,987,134	597,884	15	45,462	1	552,423-	14-
2011	17,737,600	2,541,970	14	34,636	0	2,507,334-	14-
2012	11,636,251	2,473,206	21	199,351	2	2,273,855-	20-
2013	5,121,553	4,060,365	79	76,189	1	3,984,177-	78-
2014	6,768,408	1,151,687	17		0	1,151,687-	17-
2015	18,814,164	5,191,059	28	44,171	0	5,146,888-	27-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2016	8,494,131	1,452,191	17	22,890	0	1,429,301-	17-
2017	8,073,501	10,017,154	124		0	10,017,154-	124-
TOTAL	235,583,683	59,174,907	25	2,202,309	1	56,972,598-	24-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
73-75	24,520	3,803	16	348	1	3,455-	14-
74-76	4,660	2,412	52	132	3	2,281-	49-
75-77	110,825	21,014	19	2,047	2	18,967-	17-
76-78	174,678	20,961	12	2,612	1	18,349-	11-
77-79	863,329	24,294	3	2,612	0	21,683-	3-
78-80	939,194	16,591	2	2,359	0	14,231-	2-
79-81	2,755,061	60,025	2	1,667	0	58,358-	2-
80-82	2,495,253	68,552	3	1,667	0	66,885-	3-
81-83	3,268,212	66,871	2	3,512	0	63,359-	2-
82-84	7,724,052	491,730	6	11,871	0	479,860-	6-
83-85	11,072,844	1,102,813	10	20,134	0	1,082,678-	10-
84-86	11,643,195	1,771,980	15	24,440	0	1,747,540-	15-
85-87	7,210,489	1,597,654	22	18,602	0	1,579,052-	22-
86-88	3,758,984	1,048,060	28	10,311	0	1,037,749-	28-
87-89	2,614,715	377,270	14	2,493	0	374,777-	14-
88-90	802,465	98,398	12	28-	0	98,426-	12-
89-91	646,836	25,703	4		0	25,703-	4-
90-92	482,374	3,311	1		0	3,311-	1-
91-93	633,321	55,521-	9-	2,897	0	58,419	9
92-94	634,599	22,075-	3-	4,314	1	26,389	4
93-95	3,212,550	219,542	7	18,138	1	201,404-	6-
94-96	3,651,133	468,049	13	47,105	1	420,945-	12-
95-97	3,999,577	496,802	12	109,438	3	387,364-	10-
96-98	2,117,138	692,163	33	95,614	5	596,548-	28-
97-99	3,571,762	1,194,441	33	77,418	2	1,117,023-	31-
98-00	3,696,894	1,314,728	36	120,206	3	1,194,522-	32-
99-01	5,467,918	1,000,299	18	120,206	2	880,093-	16-
00-02	5,167,422	458,435	9	106,538	2	351,897-	7-
01-03	6,884,422	278,359	4		0	278,359-	4-
02-04	6,499,215	833,077	13		0	833,077-	13-
03-05	6,063,158	1,027,514	17		0	1,027,514-	17-
04-06	12,937,054	4,432,282	34	192,527	1	4,239,756-	33-
05-07	11,668,403	4,039,366	35	286,223	2	3,753,143-	32-
06-08	11,534,714	4,179,917	36	315,110	3	3,864,806-	34-
07-09	4,634,928	1,789,808	39	131,648	3	1,658,161-	36-
08-10	4,932,127	1,717,273	35	53,105	1	1,664,168-	34-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
09-11	9,579,116	2,064,343	22	35,763	0	2,028,580-	21-
10-12	11,120,328	1,871,020	17	93,150	1	1,777,870-	16-
11-13	11,498,468	3,025,181	26	103,392	1	2,921,788-	25-
12-14	7,842,070	2,561,753	33	91,847	1	2,469,906-	31-
13-15	10,234,708	3,467,704	34	40,120	0	3,427,584-	33-
14-16	11,358,901	2,598,312	23	22,354	0	2,575,959-	23-
15-17	11,793,932	5,553,468	47	22,354	0	5,531,114-	47-
FIVE-YEAR AVERAGE							
13-17	9,454,351	4,374,491	46	28,650	0	4,345,841-	46-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1974	5,300	3,167	60		0	3,167-	60-
1975	5,583		0		0		0
1976							
1977							
1978	17,277	2,051	12	2,818	16	767	4
1979	1,527,611		0		0		0
1980	8,705		0		0		0
1981	3,710,700		0		0		0
1982	6,074	620	10		0	620-	10-
1983	2,465,234		0		0		0
1984	2,791,319		0		0		0
1985	7,690,532	899	0		0	899-	0
1986	18,073	813	4		0	813-	4-
1987	43,600	2,606	6	17	0	2,589-	6-
1988	122,693		0		0		0
1989							
1990	15,000		0		0		0
1991	1,406,443		0		0		0
1992	15,000		0		0		0
1993	22,000	524	2		0	524-	2-
1994	110,318	22,262	20		0	22,262-	20-
1995	4,566,240	377,019	8	22,567	0	354,452-	8-
1996	1,314,385	530,805	40	61,486	5	469,319-	36-
1997	612,710	73,876	12	74,929	12	1,053	0
1998							
1999	5,000	1,782	36	34	1	1,748-	35-
2000							
2001							
2002	94,480		0		0		0
2003	3,077,538	277,920	9		0	277,920-	9-
2004	1,160,157	373,601	32		0	373,601-	32-
2005	464,123	60,425	13		0	60,425-	13-
2006	2,965,022	532,312	18		0	532,312-	18-
2007	115,565	2,600	2		0	2,600-	2-
2008	33,017	46,464	141		0	46,464-	141-
2009	754,568	465,855	62		0	465,855-	62-
2010	103,475	3,278	3		0	3,278-	3-
2011	3,093,988	109,173	4		0	109,173-	4-
2012	2,675,754	1,278,417	48		0	1,278,417-	48-
2013	998,736	661,894	66		0	661,894-	66-
2014	564,792	500,640	89		0	500,640-	89-
2015	7,699,476	1,289,267	17	923,936	12	365,331-	5-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2016	1,079,649	953,014	88		0	953,014-	88-
2017	1,207,097	296,938	25	748,976	62	452,038	37
TOTAL	52,567,234	7,868,222	15	1,834,763	3	6,033,460-	11-
THREE-YEAR MOVING AVERAGES							
74-76	3,628	1,056	29		0	1,056-	29-
75-77	1,861		0		0		0
76-78	5,759	684	12	939	16	256	4
77-79	514,963	684	0	939	0	256	0
78-80	517,864	684	0	939	0	256	0
79-81	1,749,005		0		0		0
80-82	1,241,826	207	0		0	207-	0
81-83	2,060,669	207	0		0	207-	0
82-84	1,754,209	207	0		0	207-	0
83-85	4,315,695	300	0		0	300-	0
84-86	3,499,975	571	0		0	571-	0
85-87	2,584,068	1,439	0	6	0	1,434-	0
86-88	61,455	1,140	2	6	0	1,134-	2-
87-89	55,431	869	2	6	0	863-	2-
88-90	45,898		0		0		0
89-91	473,814		0		0		0
90-92	478,814		0		0		0
91-93	481,148	175	0		0	175-	0
92-94	49,106	7,595	15		0	7,595-	15-
93-95	1,566,186	133,268	9	7,522	0	125,746-	8-
94-96	1,996,981	310,029	16	28,018	1	282,011-	14-
95-97	2,164,445	327,233	15	52,994	2	274,239-	13-
96-98	642,365	201,560	31	45,472	7	156,089-	24-
97-99	205,903	25,219	12	24,988	12	232-	0
98-00	1,667	594	36	11	1	583-	35-
99-01	1,667	594	36	11	1	583-	35-
00-02	31,493		0		0		0
01-03	1,057,339	92,640	9		0	92,640-	9-
02-04	1,444,058	217,174	15		0	217,174-	15-
03-05	1,567,273	237,316	15		0	237,316-	15-
04-06	1,529,767	322,113	21		0	322,113-	21-
05-07	1,181,570	198,446	17		0	198,446-	17-
06-08	1,037,868	193,792	19		0	193,792-	19-
07-09	301,050	171,639	57		0	171,639-	57-
08-10	297,020	171,866	58		0	171,866-	58-
09-11	1,317,344	192,769	15		0	192,769-	15-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
10-12	1,957,739	463,623	24		0	463,623-	24-
11-13	2,256,159	683,161	30		0	683,161-	30-
12-14	1,413,094	813,650	58		0	813,650-	58-
13-15	3,087,668	817,267	26	307,979	10	509,289-	16-
14-16	3,114,639	914,307	29	307,979	10	606,328-	19-
15-17	3,328,741	846,406	25	557,637	17	288,769-	9-
FIVE-YEAR AVERAGE							
13-17	2,309,950	740,351	32	334,582	14	405,768-	18-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1972	33,729	502	1		0	502-	1-
1973	7,724		0	1,966	25	1,966	25
1974	10,311	417	4		0	417-	4-
1975	11,172	521	5	2,381	21	1,860	17
1976	3,903	38,121	977	2,393	61	35,728-	915-
1977	22,153	794	4		0	794-	4-
1978	23,703	1,238	5	4,573	19	3,335	14
1979	140,861	388	0	123	0	265-	0
1980	127,304	1,849	1		0	1,849-	1-
1981	963,033		0	1,261	0	1,261	0
1982	8,574	993	12	999	12	6	0
1983	302,710	13-	0	688	0	701	0
1984	1,628,052	4,221	0		0	4,221-	0
1985	1,108,851	2,002	0		0	2,002-	0
1986	13,971		0		0		0
1987	807,408	95,681	12	926	0	94,755-	12-
1988	12,928	3,297	26	10-	0	3,307-	26-
1989	97,796		0		0		0
1990	76,484	16,433-	21-	2,100	3	18,533	24
1991	313,936	1,028	0		0	1,028-	0
1992	61,486	10,547	17		0	10,547-	17-
1993	473,682	6,732-	1-		0	6,732	1
1994	22,000		0		0		0
1995	822,779	67,935	8	4,066	0	63,869-	8-
1996	348,770	140,848	40	16,315	5	124,533-	36-
1997	1,032,181	124,452	12	126,227	12	1,775	0
1998							
1999	2,918	1,040	36	21	1	1,019-	35-
2000	671,474	16,128	2		0	16,128-	2-
2001	34,589		0		0		0
2002	102,272		0		0		0
2003	74,452		0		0		0
2004	829,101	26,830	3		0	26,830-	3-
2005							
2006	1,043,304	59,113	6		0	59,113-	6-
2007	106,068	23,111	22	500	0	22,611-	21-
2008	32,633	1,065	3		0	1,065-	3-
2009	197,219	109,483	56		0	109,483-	56-
2010	20,993	18,899	90		0	18,899-	90-
2011	639,407	243,700	38		0	243,700-	38-
2012	282,287	303,914	108	11,875	4	292,039-	103-
2013	671,068	33,992	5		0	33,992-	5-
2014	196,133	211,869	108		0	211,869-	108-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2015	103,922	131,720	127	27,260	26	104,461-	101-
2016	173,708	56,804	33	42,500	24	14,304-	8-
2017	22,054	19,822	90		0	19,822-	90-
TOTAL	13,679,104	1,729,147	13	246,164	2	1,482,983-	11-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
72-74	17,255	306	2	655	4	349	2
73-75	9,736	313	3	1,449	15	1,136	12
74-76	8,462	13,020	154	1,591	19	11,428-	135-
75-77	12,409	13,145	106	1,591	13	11,554-	93-
76-78	16,586	13,384	81	2,322	14	11,062-	67-
77-79	62,239	807	1	1,565	3	759	1
78-80	97,289	1,158	1	1,565	2	407	0
79-81	410,399	746	0	461	0	284-	0
80-82	366,304	947	0	753	0	194-	0
81-83	424,772	327	0	983	0	656	0
82-84	646,445	1,734	0	562	0	1,171-	0
83-85	1,013,204	2,070	0	229	0	1,841-	0
84-86	916,958	2,074	0		0	2,074-	0
85-87	643,410	32,561	5	309	0	32,252-	5-
86-88	278,102	32,993	12	305	0	32,687-	12-
87-89	306,044	32,993	11	305	0	32,687-	11-
88-90	62,403	4,379-	7-	697	1	5,075	8
89-91	162,739	5,135-	3-	700	0	5,835	4
90-92	150,635	1,619-	1-	700	0	2,319	2
91-93	283,035	1,614	1		0	1,614-	1-
92-94	185,723	1,272	1		0	1,272-	1-
93-95	439,487	20,401	5	1,355	0	19,046-	4-
94-96	397,850	69,594	17	6,794	2	62,801-	16-
95-97	734,577	111,078	15	48,869	7	62,209-	8-
96-98	460,317	88,433	19	47,514	10	40,919-	9-
97-99	345,033	41,831	12	42,083	12	252	0
98-00	224,797	5,723	3	7	0	5,716-	3-
99-01	236,327	5,723	2	7	0	5,716-	2-
00-02	269,445	5,376	2		0	5,376-	2-
01-03	70,438		0		0		0
02-04	335,275	8,943	3		0	8,943-	3-
03-05	301,184	8,943	3		0	8,943-	3-
04-06	624,135	28,648	5		0	28,648-	5-
05-07	383,124	27,408	7	167	0	27,241-	7-
06-08	394,002	27,763	7	167	0	27,596-	7-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	111,974	44,553	40	167	0	44,386-	40-
08-10	83,615	43,149	52		0	43,149-	52-
09-11	285,873	124,027	43		0	124,027-	43-
10-12	314,229	188,838	60	3,958	1	184,879-	59-
11-13	530,921	193,869	37	3,958	1	189,910-	36-
12-14	383,163	183,258	48	3,958	1	179,300-	47-
13-15	323,708	125,860	39	9,087	3	116,774-	36-
14-16	157,921	133,464	85	23,253	15	110,211-	70-
15-17	99,895	69,449	70	23,253	23	46,196-	46-
FIVE-YEAR AVERAGE							
13-17	233,377	90,842	39	13,952	6	76,890-	33-

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1972	985	62	6		0	62-	6-
1973							
1974	2,625		0	2,800	107	2,800	107
1975	2,166		0		0		0
1976	3,217		0		0		0
1977	4,112		0		0		0
1978	2,193		0	48	2	48	2
1979	33,145	43	0		0	43-	0
1980	1,734		0		0		0
1981	15,052		0	7,500	50	7,500	50
1982	350		0		0		0
1983	309		0		0		0
1984	344,269		0		0		0
1985	68,016		0	53	0	53	0
1986	7,808		0		0		0
1987	5,311		0		0		0
1988	1,311		0		0		0
1989	318		0	175	55	175	55
1990	17,214	1,000-	6-		0	1,000	6
1991	15,986		0		0		0
1992	5,162		0		0		0
1993	137,323		0		0		0
1994							
1995	114,896	9,487	8	568	0	8,919-	8-
1996	386,595	156,124	40	18,085	5	138,039-	36-
1997	63,113	7,610	12	7,719	12	109	0
1998							
1999							
2000							
2001							
2002		537				537-	
2003	1,600	437	27		0	437-	27-
2004	159,413	4,944	3		0	4,944-	3-
2005							
2006	85,294	1,237	1		0	1,237-	1-
2007	76,996		0		0		0
2008	37,166		0	103,285	278	103,285	278
2009	31,210	2,109	7		0	2,109-	7-
2010	18,529		0		0		0
2011	66,012		0		0		0
2012	20,219		0		0		0
2013	7,457		0		0		0
2014	94,077		0		0		0

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2015	79,363	188	0		0	188-	0
2016	123,602	5,116	4	2,650	2	2,466-	2-
2017	207,367		0		0		0
TOTAL	2,241,514	186,894	8	142,883	6	44,011-	2-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
72-74	1,203	21	2	933	78	913	76
73-75	1,597		0	933	58	933	58
74-76	2,669		0	933	35	933	35
75-77	3,165		0		0		0
76-78	3,174		0	16	1	16	1
77-79	13,150	14	0	16	0	2	0
78-80	12,357	14	0	16	0	2	0
79-81	16,644	14	0	2,500	15	2,486	15
80-82	5,712		0	2,500	44	2,500	44
81-83	5,237		0	2,500	48	2,500	48
82-84	114,976		0		0		0
83-85	137,531		0	18	0	18	0
84-86	140,031		0	18	0	18	0
85-87	27,045		0	18	0	18	0
86-88	4,810		0		0		0
87-89	2,313		0	58	3	58	3
88-90	6,281	333-	5-	58	1	392	6
89-91	11,173	333-	3-	58	1	392	4
90-92	12,787	333-	3-		0	333	3
91-93	52,824		0		0		0
92-94	47,495		0		0		0
93-95	84,073	3,162	4	189	0	2,973-	4-
94-96	167,164	55,204	33	6,218	4	48,986-	29-
95-97	188,201	57,740	31	8,791	5	48,950-	26-
96-98	149,903	54,578	36	8,601	6	45,977-	31-
97-99	21,038	2,537	12	2,573	12	36	0
98-00							
99-01							
00-02		179				179-	
01-03	533	325	61		0	325-	61-
02-04	53,671	1,973	4		0	1,973-	4-
03-05	53,671	1,794	3		0	1,794-	3-
04-06	81,569	2,060	3		0	2,060-	3-
05-07	54,097	412	1		0	412-	1-
06-08	66,485	412	1	34,428	52	34,016	51

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNTS 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	48,457	703	1	34,428	71	33,725	70
08-10	28,968	703	2	34,428	119	33,725	116
09-11	38,584	703	2		0	703-	2-
10-12	34,920		0		0		0
11-13	31,229		0		0		0
12-14	40,584		0		0		0
13-15	60,299	63	0		0	63-	0
14-16	99,014	1,768	2	883	1	885-	1-
15-17	136,777	1,768	1	883	1	885-	1-
FIVE-YEAR AVERAGE							
13-17	102,373	1,061	1	530	1	531-	1-

PART IX. DETAILED DEPRECIATION CALCULATIONS

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
RIVERPORT DISTRIBUTION CENTER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2063						
NET SALVAGE PERCENT.. -25						
2013	5,123,148.75	578,211	399,761	6,004,175	44.03	136,366
2014	33,726.75	3,018	2,087	40,072	44.09	909
2015	66,384.14	4,347	3,005	79,975	44.14	1,812
2016	49,048.13	1,961	1,356	59,954	44.20	1,356
2017	37,976.87	520	360	47,112	44.25	1,065
	5,310,284.64	588,057	406,568	6,231,288		141,508
MILL CREEK UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -10						
1965	46,093.05	39,534	46,776	3,926	13.91	282
1972	15,820,798.69	13,135,693	15,541,922	1,860,956	14.04	132,547
1975	218,872.61	178,687	211,419	29,341	14.09	2,082
1977	4,197.77	3,385	4,005	612	14.12	43
1980	21,540.90	17,013	20,129	3,566	14.16	252
1981	8,073.16	6,328	7,487	1,393	14.17	98
1987	63,301.24	46,998	55,607	14,024	14.24	985
1991	3,386.36	2,398	2,837	888	14.28	62
1995	24,680.99	16,447	19,460	7,689	14.31	537
1996	38,411.41	25,136	29,740	12,512	14.32	874
1997	9,807.25	6,296	7,449	3,339	14.32	233
1998	289,774.86	182,157	215,525	103,227	14.33	7,204
1999	37,622.65	23,113	27,347	14,038	14.34	979
2001	98,083.06	57,229	67,712	40,179	14.35	2,800
2002	180,486.93	102,186	120,905	77,631	14.36	5,406
2003	741,965.92	406,653	481,145	335,018	14.36	23,330
2004	357,057.23	188,640	223,196	169,567	14.37	11,800
2005	439,217.59	222,916	263,750	219,389	14.37	15,267
2007	22,336.81	10,289	12,174	12,397	14.38	862
2008	272,031.03	118,006	139,623	159,611	14.39	11,092
2009	52,008.41	21,086	24,949	32,261	14.39	2,242
2011	119,120.13	40,448	47,857	83,175	14.40	5,776
2012	103,784.67	31,288	37,019	77,144	14.41	5,354
2015	2,148,138.36	345,558	408,858	1,954,094	14.42	135,513
2016	111,292.14	11,465	13,565	108,856	14.42	7,549
	21,232,083.22	15,238,949	18,030,458	5,324,834		373,169

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
1975	9,819,205.32	7,746,567	9,111,356	1,689,770	15.95	105,942
1976	96,856.85	75,902	89,274	17,268	15.97	1,081
1977	4,197.78	3,267	3,843	775	15.99	48
1979	3,493.45	2,678	3,150	693	16.03	43
1986	5,995.00	4,310	5,069	1,525	16.14	94
1998	184,368.44	109,464	128,749	74,056	16.27	4,552
2003	120,824.91	61,931	72,842	60,065	16.32	3,680
2005	22,227.29	10,499	12,349	12,101	16.33	741
2006	171,004.69	76,943	90,499	97,606	16.34	5,973
2007	5,838.00	2,489	2,928	3,494	16.34	214
2011	500,905.40	155,216	182,562	368,434	16.37	22,507
2012	313,472.11	86,008	101,161	243,658	16.37	14,884
2015	2,523,154.21	363,503	427,545	2,347,925	16.39	143,254
2016	170,882.49	15,664	18,424	169,547	16.39	10,345
2017	218,586.90	6,975	8,204	232,242	16.40	14,161
	14,161,012.84	8,721,416	10,257,954	5,319,160		327,519
MILL CREEK UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
1984	818,857.06	600,931	455,437	445,305	16.11	27,642
2015	4,151,771.11	598,133	453,317	4,113,632	16.39	250,984
	4,970,628.17	1,199,064	908,754	4,558,937		278,626
MILL CREEK UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1980	6,510.54	4,613	6,090	1,071	19.76	54
1982	21,290,656.69	14,786,979	19,523,058	3,896,664	19.82	196,603
1984	108,138.64	73,498	97,038	21,914	19.87	1,103
1986	436,730.18	289,909	382,763	97,640	19.91	4,904
1987	164,685.65	107,935	142,505	38,649	19.93	1,939
1988	31,410.69	20,310	26,815	7,737	19.95	388

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1997	7,192.32	3,940	5,202	2,710	20.12	135
2002	21,186.01	9,994	13,195	10,110	20.19	501
2004	249,234.02	108,465	143,205	130,952	20.21	6,480
2006	240,970.16	94,944	125,353	139,714	20.23	6,906
2009	414,775.80	133,112	175,746	280,507	20.27	13,839
2010	229,013.42	67,239	88,775	163,140	20.27	8,048
2016	5,922,786.05	442,112	583,715	5,931,350	20.33	291,754
	29,123,290.17	16,143,050	21,313,461	10,722,158		532,654
MILL CREEL UNIT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1982	124,786.75	86,668	30,882	106,384	19.82	5,368
2016	5,359,168.04	400,040	142,543	5,752,542	20.33	282,958
2017	10,561.49	279	99	11,518	20.33	567
	5,494,516.28	486,987	173,524	5,870,444		288,893
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1978	16,235.95	10,997	12,381	5,478	23.31	235
1983	2,920,019.88	1,873,123	2,108,877	1,103,145	23.51	46,922
1984	33,105,032.98	20,971,707	23,611,238	12,804,298	23.55	543,707
1985	16,032.01	10,026	11,288	6,347	23.58	269
1986	10,854,342.52	6,697,140	7,540,052	4,399,724	23.61	186,350
1987	2,747,622.50	1,670,925	1,881,230	1,141,155	23.65	48,252
1988	1,132,027.85	678,178	763,535	481,696	23.68	20,342
1989	420,234.94	247,817	279,008	183,251	23.71	7,729
1990	139,393.92	80,836	91,010	62,323	23.74	2,625
1991	31,466.81	17,928	20,184	14,429	23.77	607
1994	168,295.50	90,337	101,707	83,418	23.85	3,498
1995	1,130,198.34	593,289	667,961	575,257	23.87	24,100
1996	311,789.92	159,755	179,862	163,107	23.90	6,825
1997	227,958.65	113,845	128,174	122,581	23.92	5,125

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1998	442,793.64	215,140	242,218	244,855	23.94	10,228
1999	113,470.26	53,527	60,264	64,553	23.96	2,694
2000	74,447.42	34,019	38,301	43,591	23.98	1,818
2001	687,863.94	303,379	341,563	415,088	24.01	17,288
2002	586,204.16	249,102	280,454	364,370	24.02	15,169
2003	1,368,701.79	557,845	628,056	877,516	24.04	36,502
2004	292,312.92	113,856	128,186	193,358	24.06	8,036
2005	525,643.99	194,648	219,147	359,062	24.08	14,911
2006	166,238.65	58,196	65,521	117,342	24.10	4,869
2007	19,894.23	6,541	7,364	14,519	24.11	602
2008	25,127.93	7,695	8,664	18,977	24.13	786
2009	956,448.27	270,146	304,147	747,946	24.14	30,984
2010	483,570.90	124,205	139,838	392,090	24.16	16,229
2011	1,236,829.35	284,483	320,288	1,040,224	24.17	43,038
2012	252,495.83	50,686	57,065	220,680	24.19	9,123
2013	479,312.70	81,428	91,677	435,567	24.20	17,999
2014	9,500,493.24	1,300,152	1,463,791	8,986,751	24.21	371,200
2015	879,677.92	89,217	100,446	867,200	24.22	35,805
2016	340,734.69	21,578	24,294	350,514	24.23	14,466
2017	1,627,997.79	35,476	39,941	1,750,857	24.25	72,200
	73,280,911.39	37,267,222	41,957,732	38,651,271		1,620,533
MILL CREEK UNIT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1983	1,812,836.17	1,162,891	1,474,208	519,912	23.51	22,115
1984	320,219.90	202,856	257,162	95,079	23.55	4,037
2001	58,236.12	25,685	32,561	31,499	24.01	1,312
2004	212,084.02	82,607	104,722	128,571	24.06	5,344
2005	14,020.31	5,192	6,582	8,840	24.08	367
2006	12,043.50	4,216	5,345	7,903	24.10	328
2013	7,305.53	1,241	1,573	6,463	24.20	267
2014	3,337,266.72	456,708	578,973	3,092,020	24.21	127,717
2017	18,363.52	400	507	19,693	24.25	812
	5,792,375.79	1,941,796	2,461,633	3,909,980		162,299

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 95-R2.5 PROBABLE RETIREMENT YEAR.. 6-2050 NET SALVAGE PERCENT.. -14						
1990	103,453,966.09	54,067,277	64,520,573	53,416,949	31.01	1,722,572
1993	261,010.60	127,840	152,556	144,996	31.17	4,652
1994	362,457.24	173,363	206,881	206,320	31.21	6,611
1995	520,162.37	242,507	289,393	303,592	31.26	9,712
1996	124,393.22	56,423	67,332	74,477	31.31	2,379
1997	540,527.91	238,236	284,296	331,906	31.35	10,587
1998	291,947.64	124,684	148,790	184,030	31.40	5,861
1999	20,033.30	8,276	9,876	12,962	31.44	412
2000	112,766.78	44,941	53,630	74,924	31.48	2,380
2001	60,760.43	23,293	27,796	41,470	31.52	1,316
2002	259,907.60	95,543	114,015	182,280	31.56	5,776
2003	446,282.16	156,775	187,086	321,676	31.59	10,183
2004	80,252.62	26,809	31,992	59,496	31.63	1,881
2006	5,878.80	1,747	2,085	4,617	31.70	146
2007	3,126.83	868	1,036	2,529	31.73	80
2008	510,515.04	131,378	156,778	425,209	31.76	13,388
2009	150,166.01	35,409	42,255	128,934	31.79	4,056
2010	85,397.39	18,207	21,727	75,626	31.82	2,377
2011	33,353.80	6,322	7,544	30,479	31.84	957
2013	43,040.44	5,947	7,097	41,969	31.90	1,316
2017	116,477.02	2,004	2,391	130,392	31.99	4,076
	107,482,423.29	55,587,849	66,335,130	56,194,833		1,810,718
TRIMBLE COUNTY UNIT 1 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 95-R2.5 PROBABLE RETIREMENT YEAR.. 6-2050 NET SALVAGE PERCENT.. -14						
1990	101,916.70	53,264	1,970	114,215	31.01	3,683
1996	20,052.22	9,095	336	22,523	31.31	719
2004	61,254.94	20,462	757	69,074	31.63	2,184
2013	705,791.36	97,526	3,607	800,995	31.90	25,110
	889,015.22	180,347	6,671	1,006,806		31,696

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
1990	22,344.25	9,383	10,043	15,430	44.36	348
2011	15,149,274.41	2,053,942	2,198,375	15,071,798	46.60	323,429
2012	409,666.94	47,781	51,141	415,879	46.68	8,909
2013	86,118.30	8,375	8,964	89,211	46.75	1,908
2014	154,925.17	11,960	12,801	163,814	46.81	3,500
2015	176,813.39	9,933	10,631	190,936	46.88	4,073
2016	404,264.65	13,904	14,882	445,980	46.94	9,501
2017	999,973.89	11,764	12,591	1,127,379	47.00	23,987
	17,403,381.00	2,167,042	2,319,428	17,520,426		375,655
TRIMBLE COUNTY UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
2011	69,521.69	9,426	7,436	71,819	46.60	1,541
2012	411.79	48	38	432	46.68	9
2017	14,666.45	173	136	16,583	47.00	353
	84,599.93	9,647	7,610	88,834		1,903
	285,224,521.94	139,531,426	164,178,923	155,398,971		5,945,173

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.1   2.08

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CANE RUN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1955	1,639,190.12	1,803,109	1,803,109			
1986	0.40		0			
1997	39,193.77	43,113	43,113			
1998	41,520.99	45,673	45,673			
2000	10.83	12	12			
2014	33,589.49	36,948	36,948			
2015	32,299.10	35,529	35,529			
2016	373.59	411	411			
	1,786,178.29	1,964,795	1,964,796			
CANE RUN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1956	1,184,900.77	1,303,391	1,303,391			
1997	43,063.97	47,370	47,370			
2016	373.59	411	411			
	1,228,338.33	1,351,172	1,351,172			
CANE RUN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1959	1,952,265.06	2,147,492	2,147,492			
1975	44.28	49	49			
1997	82,878.31	91,166	91,166			
2016	373.68	411	411			
	2,035,561.33	2,239,118	2,239,117			

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CANE RUN UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1964	1,814,704.93	1,996,175	1,996,175			
1966	107.89	119	119			
1969	301.74	332	332			
1994	19,409.75	21,351	21,351			
1997	97,687.75	107,457	107,457			
2009	99,942.00	109,936	109,936			
2012	80,618.11	88,680	88,680			
2013	1,018,709.71	1,120,581	1,120,581			
2016	373.61	411	411			
	3,131,855.49	3,445,042	3,445,041			
CANE RUN UNIT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
2014	17,192.20	18,911	18,911			
2016	373.59	411	411			
	17,565.79	19,322	19,322			
CANE RUN UNIT 5						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1967	2,209,914.99	2,430,906	2,430,906			
1997	460,252.28	506,278	506,278			
1998	77,110.41	84,821	84,821			
2012	213,621.33	234,983	234,983			
2014	155,851.67	171,437	171,437			
2015	28,789.01	31,668	31,668			
2016	124.53	137	137			
	3,145,664.22	3,460,230	3,460,231			

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CANE RUN UNIT 5 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1979	5.68	6	6			
1980	5.63	6	6			
2015	9,932.90	10,926	10,926			
2016	249.06	274	274			
	10,193.27	11,212	11,213			
CANE RUN UNIT 6						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1968	25,970.52	28,568	28,568			
1970	2,318,410.10	2,550,251	2,550,251			
1973	157,004.65	172,705	172,705			
1977	65,482.34	72,031	72,031			
1978	104,011.35	114,412	114,412			
1983	1,000,000.00	1,100,000	1,100,000			
1984	147,868.83	162,656	162,656			
1987	240,188.77	264,208	264,208			
1997	67,252.33	73,978	73,978			
1998	6,924.37	7,617	7,617			
1999	0.21		0			
2001	583,023.78	641,326	641,326			
2002	675,474.89	743,022	743,022			
2003	74,876.34	82,364	82,364			
2004	181,731.32	199,904	199,904			
2006	46,381.08	51,019	51,019			
2007	1,124,191.86	1,236,611	1,236,611			
2009	1,407,414.03	1,548,155	1,548,155			
2010	143,677.89	158,046	158,046			
2011	762,918.87	839,211	839,211			
2013	70,027.02	77,030	77,030			
2014	3,870,067.88	4,257,075	4,257,075			
2015	31,265.63	34,392	34,392			
2016	249.06	274	274			
	13,104,413.12	14,414,855	14,414,854			

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 311.2 STRUCTURES AND IMPROVEMENTS - RETIRED PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CANE RUN UNIT 6 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 95-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
2014	85,553.36	94,109	94,109			
2016	373.59	411	411			
	85,926.95	94,520	94,520			
	24,545,696.79	27,000,266	27,000,266			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -10						
1972	21,414,326.49	17,293,932	14,223,253	9,332,506	12.85	726,265
1973	7,875.43	6,326	5,203	3,460	12.90	268
1975	265,320.08	210,671	173,265	118,587	12.99	9,129
1976	1,821.92	1,438	1,183	821	13.04	63
1977	35,816.91	28,085	23,098	16,300	13.08	1,246
1978	121,581.83	94,704	77,889	55,851	13.12	4,257
1979	5,258.44	4,068	3,346	2,439	13.16	185
1980	40,473.88	31,083	25,564	18,957	13.20	1,436
1981	68,546.02	52,238	42,963	32,438	13.24	2,450
1982	350,502.00	264,967	217,920	167,632	13.28	12,623
1983	208,728.99	156,510	128,720	100,882	13.31	7,579
1984	13,324.05	9,902	8,144	6,513	13.35	488
1986	373,158.68	272,173	223,846	186,628	13.41	13,917
1987	186,502.84	134,636	110,730	94,423	13.44	7,026
1988	1,185.12	846	696	608	13.47	45
1989	64,563.44	45,581	37,488	33,532	13.50	2,484
1992	48,372.08	32,855	27,021	26,188	13.58	1,928
1993	23,285.15	15,582	12,815	12,798	13.61	940
1994	330,734.56	217,921	179,227	184,581	13.63	13,542
1995	272,815.11	176,787	145,397	154,700	13.65	11,333
1996	449,017.28	285,851	235,096	258,823	13.67	18,934
1997	775,321.29	484,190	398,218	454,635	13.69	33,209
1998	5,657,245.57	3,459,225	2,845,011	3,377,959	13.71	246,387
1999	3,906,667.89	2,335,172	1,920,543	2,376,792	13.73	173,109
2000	203,312.67	118,585	97,529	126,115	13.75	9,172
2001	962,802.63	546,476	449,445	609,638	13.77	44,273
2002	496,398.14	273,712	225,112	320,926	13.78	23,289
2003	2,979,926.02	1,590,020	1,307,699	1,970,220	13.80	142,770
2004	2,902,846.86	1,494,481	1,229,124	1,964,008	13.81	142,216
2005	298,953.89	147,798	121,555	207,294	13.83	14,989
2006	1,876,339.42	886,497	729,092	1,334,881	13.84	96,451
2007	141,819.17	63,600	52,307	103,694	13.86	7,482
2008	3,673,504.84	1,554,315	1,278,334	2,762,522	13.87	199,172
2009	101,933.21	40,256	33,108	79,018	13.89	5,689
2010	11,986.69	4,370	3,594	9,591	13.90	690
2011	3,542,654.92	1,173,012	964,734	2,932,186	13.91	210,797
2012	162,731.37	47,835	39,342	139,663	13.93	10,026
2013	6,800,891.07	1,722,570	1,416,714	6,064,267	13.94	435,026
2014	448,194.73	93,387	76,805	416,209	13.95	29,836

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 60-R1 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -10						
2015	121,894,793.03	19,166,006	15,762,925	118,321,347	13.97	8,469,674
2016	383,790.87	38,430	31,606	390,564	13.98	27,937
2017	630,818.53	22,552	18,548	675,353	13.99	48,274
	182,136,143.11	54,598,645	44,904,210	155,445,547		11,206,606
MILL CREEK UNIT 1 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 60-R1 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -10						
1991	5,546,971.24	3,818,607	3,803,553	2,298,116	13.56	169,478
1997	2,685,050.95	1,676,822	1,670,211	1,283,345	13.69	93,743
1998	39.61	24	24	20	13.71	1
2001	9,599.04	5,448	5,427	5,132	13.77	373
2002	2,876,370.68	1,586,022	1,579,769	1,584,238	13.78	114,966
2003	5,225,116.30	2,788,002	2,777,011	2,970,617	13.80	215,262
2004	100,971.20	51,983	51,778	59,290	13.81	4,293
2005	54,427.99	26,908	26,802	33,069	13.83	2,391
2008	430,882.82	182,313	181,594	292,377	13.87	21,080
	16,929,429.83	10,136,129	10,096,169	8,526,204		621,587
MILL CREEK UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 60-R1 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -10						
1975	17,054,608.27	13,058,696	6,248,152	12,511,917	14.53	861,109
1979	327,798.84	243,816	116,658	243,921	14.75	16,537
1980	2,634.46	1,944	930	1,968	14.80	133
1981	148,305.42	108,512	51,919	111,217	14.85	7,489
1982	70,679.74	51,257	24,525	53,223	14.90	3,572
1983	83,301.87	59,869	28,645	62,987	14.94	4,216
1984	80,377.49	57,201	27,369	61,046	14.99	4,072
1986	231,601.12	161,463	77,255	177,507	15.07	11,779
1987	20,698.83	14,270	6,828	15,941	15.11	1,055
1988	963.59	656	314	746	15.15	49
1989	64,563.44	43,429	20,779	50,240	15.19	3,307
1992	52,695.31	33,992	16,264	41,701	15.29	2,727

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
1993	4,287.61	2,721	1,302	3,414	15.33	223
1995	154,316.73	94,570	45,249	124,500	15.39	8,090
1996	46,271.80	27,823	13,312	37,587	15.41	2,439
1997	648,626.26	381,874	182,714	530,775	15.44	34,377
1998	3,474,151.24	1,999,711	956,795	2,864,771	15.47	185,182
1999	1,444,123.25	811,567	388,308	1,200,228	15.49	77,484
2001	2,429,671.48	1,291,446	617,914	2,054,725	15.54	132,222
2002	5,996,535.49	3,089,655	1,478,297	5,117,892	15.56	328,913
2003	2,880,639.68	1,433,426	685,847	2,482,857	15.58	159,362
2004	1,373,435.07	657,793	314,732	1,196,046	15.60	76,670
2005	1,683,302.66	772,427	369,581	1,482,052	15.62	94,882
2006	352,406.11	154,101	73,732	313,915	15.64	20,071
2008	1,251,577.09	486,910	232,970	1,143,765	15.68	72,944
2009	412,257.46	149,223	71,398	382,085	15.70	24,337
2010	4,479,120.12	1,492,989	714,346	4,212,687	15.71	268,153
2011	410,920.22	123,901	59,283	392,730	15.73	24,967
2012	4,552,070.67	1,213,864	580,794	4,426,484	15.75	281,047
2014	2,660,793.03	497,305	237,944	2,688,928	15.78	170,401
2015	141,800,521.60	19,895,322	9,519,250	146,461,323	15.80	9,269,704
2016	3,688,099.88	327,677	156,783	3,900,127	15.82	246,531
2017	620,928.88	19,692	9,422	673,600	15.83	42,552
	198,502,284.71	48,759,102	23,329,610	195,022,903		12,436,596
MILL CREEK UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
2002	203,535.72	104,870	21,603	202,286	15.56	13,000
2005	6,998.17	3,211	661	7,037	15.62	451
2008	332,266.71	129,264	26,628	338,865	15.68	21,611
2015	111,645,216.21	15,664,382	3,226,865	119,582,873	15.80	7,568,536
2016	34,447.60	3,061	631	37,262	15.82	2,355
2017	2,599,527.05	82,439	16,982	2,842,497	15.83	179,564
	114,821,991.46	15,987,227	3,293,371	123,010,820		7,785,517

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1979	4,767.06	3,299	2,734	2,510	17.73	142
1980	3,428,357.32	2,350,019	1,947,582	1,823,612	17.81	102,393
1981	11,318.35	7,681	6,366	6,085	17.89	340
1982	44,978,625.60	30,213,807	25,039,735	24,436,753	17.96	1,360,621
1984	1,957,212.86	1,286,012	1,065,784	1,087,150	18.10	60,064
1985	1,704.37	1,107	917	957	18.17	53
1986	608,706.59	390,297	323,459	346,118	18.24	18,976
1987	123,117.61	77,927	64,582	70,847	18.30	3,871
1988	401,560.78	250,714	207,780	233,937	18.36	12,742
1990	65,980.65	39,984	33,137	39,442	18.48	2,134
1992	63,366.14	37,145	30,784	38,919	18.59	2,094
1993	72,295.22	41,613	34,487	45,038	18.64	2,416
1994	175,632.11	99,163	82,181	111,014	18.69	5,940
1995	2,177,981.40	1,205,197	998,809	1,396,971	18.73	74,585
1996	261,791.90	141,688	117,424	170,547	18.78	9,081
1997	641,399.71	339,139	281,062	424,478	18.82	22,555
1998	186,673.04	96,249	79,766	125,574	18.86	6,658
1999	499,059.76	250,394	207,514	341,451	18.90	18,066
2000	9,899.82	4,822	3,996	6,894	18.94	364
2001	321,317.64	151,510	125,564	227,885	18.98	12,007
2002	1,558,350.90	709,982	588,399	1,125,787	19.01	59,221
2003	18,848,257.17	8,261,719	6,846,911	13,886,172	19.05	728,933
2004	52,849,370.86	22,202,655	18,400,481	39,733,826	19.08	2,082,486
2005	107,671.37	43,168	35,776	82,663	19.11	4,326
2006	958,853.85	365,035	302,523	752,216	19.14	39,301
2007	1,996,474.13	716,353	593,679	1,602,443	19.17	83,591
2008	46,235.80	15,517	12,860	38,000	19.20	1,979
2009	1,282,542.79	398,494	330,252	1,080,545	19.23	56,191
2010	98,917.56	28,083	23,274	85,535	19.26	4,441
2011	2,020,997.52	515,959	427,602	1,795,496	19.29	93,079
2012	1,346,461.45	302,205	250,453	1,230,655	19.31	63,731
2013	11,697,943.12	2,232,552	1,850,231	11,017,507	19.34	569,675
2014	190,039.04	29,400	24,365	184,678	19.37	9,534
2015	864,249.38	100,020	82,892	867,783	19.39	44,754
2016	126,466,623.40	9,167,566	7,597,633	131,515,653	19.42	6,772,176
2017	1,189,192.61	29,576	24,511	1,283,601	19.45	65,995
	277,512,948.88	82,106,051	68,045,505	237,218,739		12,394,515

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEL UNIT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1982	612,880.78	411,695	120,512	553,657	17.96	30,827
1996	185,176.23	100,221	29,337	174,357	18.78	9,284
2001	1,482,747.00	699,154	204,657	1,426,365	18.98	75,151
2003	765,122.16	335,374	98,171	743,463	19.05	39,027
2004	1,973,751.17	829,197	242,723	1,928,403	19.08	101,069
2007	72,067.10	25,858	7,569	71,705	19.17	3,740
2016	144,698,844.87	10,489,219	3,070,416	156,098,314	19.42	8,038,018
2017	546,111.42	13,582	3,976	596,747	19.45	30,681
	150,336,700.73	12,904,300	3,777,361	161,593,010		8,327,797
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1980	440,249.54	282,540	272,557	211,718	20.57	10,293
1981	227,438.94	144,315	139,216	110,967	20.68	5,366
1982	333,336.91	208,973	201,589	165,081	20.79	7,940
1984	75,257,757.35	46,016,055	44,390,163	38,393,370	20.99	1,829,127
1985	332,766.67	200,735	193,642	172,401	21.09	8,175
1986	8,768,653.94	5,216,876	5,032,547	4,612,972	21.18	217,798
1987	376,721.61	220,797	212,996	201,398	21.28	9,464
1988	462,429.35	266,956	257,524	251,149	21.36	11,758
1989	811,031.27	460,654	444,378	447,757	21.45	20,874
1990	1,327,667.49	741,404	715,208	745,226	21.53	34,613
1991	5,021,081.98	2,753,918	2,656,613	2,866,577	21.61	132,650
1992	844,777.73	454,564	438,503	490,753	21.69	22,626
1993	114,757.39	60,505	58,367	67,866	21.77	3,117
1994	250,426.34	129,267	124,700	150,769	21.84	6,903
1995	797,416.49	402,396	388,178	488,980	21.91	22,318
1996	3,239,846.39	1,596,561	1,540,149	2,023,682	21.97	92,111
1997	876,303.85	420,584	405,723	558,211	22.04	25,327
1998	3,656,385.26	1,707,269	1,646,946	2,375,078	22.10	107,470
1999	1,833,933.14	831,239	801,869	1,215,458	22.16	54,849
2000	5,871,514.94	2,578,558	2,487,449	3,971,217	22.21	178,803
2001	25,318,630.11	10,736,087	10,356,747	17,493,746	22.27	785,530
2002	4,879,231.04	1,992,663	1,922,256	3,444,898	22.32	154,341
2003	62,520,901.01	24,501,066	23,635,366	45,137,625	22.37	2,017,775
2004	1,326,226.15	496,578	479,032	979,816	22.42	43,703

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
2005	2,556,930.89	910,165	878,006	1,934,618	22.47	86,098
2006	9,814,897.13	3,307,149	3,190,297	7,606,090	22.51	337,898
2007	928,271.54	293,719	283,341	737,758	22.56	32,702
2008	3,687,741.26	1,086,740	1,048,342	3,008,173	22.60	133,105
2009	2,114,686.17	574,770	554,462	1,771,693	22.64	78,255
2010	3,987,749.56	987,626	952,730	3,433,794	22.68	151,402
2011	6,739,165.81	1,490,400	1,437,739	5,975,343	22.73	262,884
2012	4,910,365.62	952,051	918,412	4,482,990	22.76	196,968
2013	749,585.26	123,063	118,715	705,829	22.80	30,957
2014	207,447,357.68	27,424,126	26,455,145	201,736,948	22.84	8,832,616
2015	5,063,304.43	496,644	479,096	5,090,539	22.88	222,489
2016	6,021,634.43	365,832	352,906	6,270,892	22.92	273,599
2017	12,545,463.90	265,374	255,998	13,544,013	22.95	590,153
	471,456,638.57	140,698,219	135,726,909	382,875,393		17,032,057
MILL CREEK UNIT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1983	4,903,950.91	3,037,340	1,365,103	4,029,243	20.89	192,879
1988	230,585.19	133,115	59,827	193,816	21.36	9,074
1989	7,208.39	4,094	1,840	6,089	21.45	284
1996	3,808,915.50	1,876,992	843,596	3,346,211	21.97	152,308
1997	68,399.24	32,828	14,754	60,485	22.04	2,744
2000	21,635,151.15	9,501,380	4,270,302	19,528,365	22.21	879,260
2001	1,393,120.25	590,737	265,501	1,266,931	22.27	56,890
2002	5,020,125.34	2,050,204	921,444	4,600,694	22.32	206,124
2003	527,503.85	206,721	92,909	487,346	22.37	21,786
2004	43,152.01	16,157	7,262	40,206	22.42	1,793
2005	198,430.50	70,633	31,745	186,528	22.47	8,301
2006	419,388.57	141,314	63,512	397,815	22.51	17,673
2007	383,959.54	121,491	54,603	367,753	22.56	16,301
2008	7,529.57	2,219	997	7,285	22.60	322
2009	100,088.52	27,204	12,227	97,871	22.64	4,323
2010	55,099.59	13,646	6,133	54,476	22.68	2,402
2011	2,128,403.02	470,707	211,555	2,129,689	22.73	93,695
2012	10,357,724.83	2,008,218	902,574	10,490,923	22.76	460,937
2013	108,472.50	17,808	8,004	111,316	22.80	4,882

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
2014	141,385,875.63	18,690,930	8,400,455	147,124,009	22.84	6,441,507
2015	12,158.39	1,193	536	12,838	22.88	561
2016	226,721.31	13,774	6,191	243,203	22.92	10,611
2017	13,327,284.78	281,912	126,703	14,533,311	22.95	633,260
	206,349,248.58	39,310,617	17,667,770	209,316,403		9,217,917
TRIMBLE COUNTY UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. -14						
1990	128,938,346.70	64,890,080	60,308,416	86,681,299	27.00	3,210,418
1992	38,267.84	18,443	17,141	26,485	27.28	971
1994	196,865.96	90,393	84,011	140,417	27.55	5,097
1995	12,880.29	5,761	5,354	9,329	27.68	337
1996	434,526.73	189,000	175,655	319,705	27.80	11,500
1997	1,429,634.78	603,770	561,140	1,068,644	27.92	38,275
1998	5,164,667.09	2,113,809	1,964,560	3,923,160	28.03	139,963
1999	300,546.33	118,924	110,527	232,096	28.14	8,248
2000	82,881.85	31,621	29,388	65,097	28.25	2,304
2001	475,951.02	174,674	162,341	380,243	28.35	13,412
2002	36,738,757.54	12,926,098	12,013,431	29,868,753	28.45	1,049,868
2003	5,176,645.95	1,739,195	1,616,396	4,284,980	28.55	150,087
2004	426,942.12	136,475	126,839	359,875	28.64	12,565
2005	3,353,308.40	1,013,875	942,289	2,880,483	28.73	100,260
2006	283,707.42	80,688	74,991	248,436	28.82	8,620
2007	272,649.64	72,490	67,372	243,449	28.90	8,424
2008	4,413,630.64	1,087,416	1,010,637	4,020,902	28.98	138,747
2009	2,660,534.52	600,900	558,473	2,474,537	29.06	85,153
2010	9,483,989.61	1,936,925	1,800,165	9,011,583	29.14	309,251
2011	10,795,021.22	1,958,428	1,820,150	10,486,174	29.22	358,870
2012	588,820.22	92,821	86,267	584,988	29.29	19,972
2013	3,422,355.95	453,353	421,343	3,480,142	29.36	118,533
2014	404,146.80	42,880	39,852	420,875	29.43	14,301
2015	85,910,747.57	6,710,729	6,236,908	91,701,345	29.50	3,108,520
2016	2,569,112.46	123,331	114,623	2,814,165	29.57	95,170
2017	19,342,589.55	315,323	293,059	21,757,493	29.64	734,058
	322,917,528.20	97,527,402	90,641,330	277,484,652		9,742,924

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. -14						
1990	50,010,558.20	25,168,534	28,728,586	28,283,450	27.00	1,047,535
1994	253,366.21	116,335	132,790	156,047	27.55	5,664
1996	7,760.87	3,376	3,854	4,994	27.80	180
1997	146,964.06	62,067	70,846	96,693	27.92	3,463
1998	546,174.12	223,540	255,159	367,479	28.03	13,110
1999	139,582.70	55,232	63,044	96,080	28.14	3,414
2002	1,958,503.95	689,077	786,546	1,446,149	28.45	50,831
2004	3,912.29	1,251	1,428	3,032	28.64	106
2005	4,281,077.44	1,294,387	1,477,476	3,402,952	28.73	118,446
2006	4,579,814.50	1,302,532	1,486,773	3,734,215	28.82	129,570
2007	850,100.00	226,017	257,987	711,127	28.90	24,606
2010	33,337.92	6,809	7,772	30,233	29.14	1,038
2012	552,605.79	87,112	99,434	530,537	29.29	18,113
2015	89,147.45	6,964	7,949	93,679	29.50	3,176
2016	3,384,658.53	162,482	185,465	3,673,046	29.57	124,215
	66,837,564.03	29,405,715	33,565,110	42,629,713		1,543,467
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
2011	127,801,331.09	16,632,372	23,884,488	121,809,030	40.35	3,018,811
2012	3,547,408.00	396,761	569,758	3,474,287	40.54	85,700
2013	749,362.16	69,922	100,410	753,863	40.72	18,513
2014	3,433,135.22	254,160	364,980	3,548,794	40.89	86,789
2015	4,526,898.46	243,067	349,050	4,811,614	41.07	117,156
2016	2,526,423.25	82,746	118,825	2,761,297	41.24	66,957
2017	3,863,446.73	43,206	62,045	4,342,284	41.40	104,886
	146,448,004.91	17,722,234	25,449,556	141,501,170		3,498,812

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
2011	14,418,804.49	1,876,498	2,930,696	13,506,741	40.35	334,740
2012	298,031.71	33,333	52,059	287,697	40.54	7,097
2013	141,070.30	13,163	20,558	140,262	40.72	3,445
2014	275,467.84	20,393	31,850	282,184	40.89	6,901
2016	18,889.14	619	967	20,567	41.24	499
	15,152,263.48	1,944,006	3,036,129	14,237,451		352,682
	2,169,400,746.49	551,099,647	459,533,030	1,948,862,005		94,160,477

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.7 4.34

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 312.1 BOILER PLANT EQUIPMENT - ASH PONDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2021 NET SALVAGE PERCENT.. 0						
1972	411,750.29	378,477	231,546	180,204	4.00	45,051
	411,750.29	378,477	231,546	180,204		45,051
MILL CREEK UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 6-2019 NET SALVAGE PERCENT.. 0						
1982	947,826.39	909,402	635,948	311,878	1.50	207,919
	947,826.39	909,402	635,948	311,878		207,919
TRIMBLE COUNTY UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2023 NET SALVAGE PERCENT.. 0						
1990	4,867,827.96	3,996,000	1,858,074	3,009,754	6.00	501,626
	4,867,827.96	3,996,000	1,858,074	3,009,754		501,626
TRIMBLE COUNTY UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 100-S4 PROBABLE RETIREMENT YEAR.. 12-2021 NET SALVAGE PERCENT.. 0						
2011	5,057,242.50	3,130,686	614,262	4,442,980	4.00	1,110,745
	5,057,242.50	3,130,686	614,262	4,442,980		1,110,745
	11,284,647.14	8,414,565	3,339,830	7,944,816		1,865,341

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.3 16.53

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -10						
1972	9,558,559.29	8,000,629	7,216,155	3,298,260	12.48	264,284
1975	33,622.25	27,621	24,913	12,072	12.78	945
1988	9,480.76	6,975	6,291	4,138	13.66	303
1992	27,075.30	18,932	17,076	12,707	13.83	919
1993	971,441.12	669,202	603,586	465,000	13.87	33,526
1994	185,064.18	125,477	113,174	90,397	13.91	6,499
1995	28,446.40	18,965	17,105	14,186	13.94	1,018
1996	254,031.63	166,350	150,039	129,396	13.97	9,262
1999	18,356.35	11,278	10,172	10,020	14.06	713
2002	180,996.96	102,521	92,469	106,628	14.13	7,546
2003	271,428.49	148,808	134,217	164,354	14.15	11,615
2004	691,281.91	365,430	329,599	430,811	14.17	30,403
2007	200,644.13	92,360	83,304	137,405	14.23	9,656
2008	175,609.64	76,185	68,715	124,456	14.25	8,734
2012	326,557.97	98,281	88,644	270,569	14.31	18,908
2013	6,506,511.77	1,688,088	1,522,568	5,634,595	14.32	393,477
2015	6,242,518.01	1,005,501	906,910	5,959,860	14.34	415,611
2017	289,718.68	10,517	9,486	309,205	14.36	21,532
	25,971,344.84	12,633,120	11,394,423	17,174,056		1,234,951
MILL CREEK UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
1975	10,010,798.61	7,982,290	7,471,761	3,540,118	14.21	249,129
1977	32,117.17	25,216	23,603	11,726	14.45	811
1986	8,428.02	6,083	5,694	3,577	15.25	235
1988	95,857.98	67,580	63,258	42,186	15.38	2,743
1995	666,220.77	422,015	395,024	337,819	15.74	21,462
1996	37,365.50	23,203	21,719	19,383	15.79	1,228
1997	333,008.13	202,459	189,510	176,799	15.83	11,169
1999	7,342.02	4,259	3,987	4,090	15.90	257
2002	1,065,664.45	566,234	530,019	642,212	16.00	40,138
2003	1,519,049.93	779,300	729,458	941,497	16.03	58,733
2005	196,319.25	92,779	86,845	129,106	16.09	8,024
2007	109,533.51	46,732	43,743	76,744	16.13	4,758
2008	56,103.77	22,466	21,029	40,685	16.16	2,518
2010	57,422.60	19,677	18,419	44,746	16.20	2,762

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
2011	266,698.44	82,633	77,348	216,020	16.22	13,318
2012	5,789,721.97	1,587,779	1,486,228	4,882,466	16.23	300,830
2013	75,226.48	17,664	16,534	66,215	16.25	4,075
2014	350,971.22	67,218	62,919	323,149	16.27	19,862
2015	7,505,834.09	1,083,820	1,014,501	7,241,916	16.28	444,835
2016	23,846.81	2,170	2,031	24,200	16.30	1,485
2017	53,605.89	1,720	1,610	57,356	16.31	3,517
	28,261,136.61	13,103,297	12,265,240	18,822,010		1,191,889
MILL CREEK UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1978	2,296,618.42	1,688,540	1,863,054	663,227	17.31	38,315
1982	18,526,289.24	13,056,162	14,405,541	5,973,377	17.92	333,336
1989	2,208.14	1,420	1,567	862	18.73	46
1993	27,779.22	16,681	18,405	12,152	19.09	637
1994	904,453.22	532,788	587,853	407,046	19.16	21,245
1995	96,282.76	55,522	61,260	44,651	19.24	2,321
1996	1,108,386.56	625,146	689,756	529,469	19.31	27,419
1997	174,257.56	95,989	105,910	85,774	19.37	4,428
1999	7,342.02	3,832	4,228	3,848	19.50	197
2003	93,997.54	42,816	47,241	56,156	19.71	2,849
2004	1,744,925.53	761,913	840,658	1,078,760	19.75	54,621
2006	107,652.56	42,508	46,901	71,517	19.84	3,605
2007	23,053.86	8,577	9,463	15,896	19.88	800
2008	1,168,159.07	406,271	448,260	836,715	19.92	42,004
2009	159,202.21	51,276	56,575	118,547	19.95	5,942
2010	260,400.84	76,546	84,457	201,984	19.99	10,104
2011	380,117.96	100,447	110,828	307,301	20.02	15,350
2012	3,017,515.58	700,166	772,529	2,546,738	20.05	127,019
2013	1,093,522.18	215,796	238,099	964,775	20.08	48,047
2014	78,875.74	12,647	13,954	72,809	20.10	3,622
2015	2,986,643.68	356,456	393,296	2,892,012	20.13	143,667
2016	475,678.68	35,576	39,253	483,994	20.15	24,020
2017	140,774.32	3,673	4,053	150,799	20.17	7,476
	34,874,136.89	18,890,748	20,843,142	17,518,409		917,070

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1984	26,543,252.72	17,216,644	17,293,775	11,903,803	20.96	567,930
1989	2,208.14	1,325	1,331	1,098	21.78	50
1990	10,208.27	6,016	6,043	5,186	21.93	236
1991	2,277,121.66	1,317,543	1,323,446	1,181,388	22.06	53,553
1992	1,626,712.57	923,000	927,135	862,249	22.19	38,858
1993	30,320.47	16,854	16,930	16,423	22.31	736
1994	51,864.99	28,198	28,324	28,727	22.43	1,281
1996	209,000.84	108,322	108,807	121,094	22.65	5,346
1997	474,920.55	239,709	240,783	281,630	22.75	12,379
1998	63,359.58	31,088	31,227	38,468	22.85	1,684
1999	7,342.02	3,495	3,511	4,566	22.94	199
2000	2,816.43	1,298	1,304	1,794	23.02	78
2001	732,712.71	325,924	327,384	478,600	23.11	20,710
2003	253,031.34	103,877	104,342	173,992	23.26	7,480
2005	1,800,731.23	671,097	674,104	1,306,701	23.40	55,842
2006	906,191.19	319,368	320,799	676,012	23.46	28,816
2008	560,545.24	172,648	173,421	443,178	23.58	18,795
2009	25,026.43	7,096	7,128	20,401	23.64	863
2011	3,696,430.48	852,737	856,557	3,209,516	23.74	135,194
2012	2,267,042.35	457,154	459,202	2,034,545	23.79	85,521
2013	139,939.53	23,900	24,007	129,926	23.83	5,452
2014	12,071,479.73	1,659,828	1,667,264	11,611,364	23.87	486,442
2015	873,461.09	88,971	89,370	871,438	23.91	36,447
2016	17,756.85	1,122	1,127	18,406	23.95	769
2017	414,559.92	9,129	9,170	446,846	23.98	18,634
	55,058,036.33	24,586,343	24,696,491	35,867,349		1,583,295
TRIMBLE COUNTY UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. -14						
1990	39,208,203.86	21,355,501	24,629,889	20,067,463	27.26	736,151
1994	38,695.05	19,133	22,067	22,046	28.24	781
1996	35,401.53	16,545	19,082	21,276	28.67	742
1997	231,629.41	104,973	121,068	142,989	28.87	4,953
1998	17,799.41	7,809	9,006	11,285	29.06	388
2000	61,094.28	24,938	28,762	40,886	29.42	1,390

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. -14						
2001	172,557.22	67,694	78,073	118,642	29.58	4,011
2002	1,635,647.75	614,268	708,452	1,156,186	29.74	38,876
2003	257,463.44	92,294	106,445	187,063	29.89	6,258
2005	65,186.67	20,982	24,199	50,114	30.17	1,661
2007	14,260,066.39	4,023,965	4,640,950	11,615,526	30.43	381,713
2008	40,206.06	10,513	12,125	33,710	30.54	1,104
2009	57,074.38	13,650	15,743	49,322	30.66	1,609
2010	670,352.58	144,946	167,170	597,032	30.76	19,409
2011	481,291.72	92,407	106,576	442,097	30.86	14,326
2012	38,994.69	6,498	7,494	36,960	30.96	1,194
2013	52,600.67	7,353	8,480	51,484	31.05	1,658
2014	195,870.01	21,863	25,215	198,077	31.14	6,361
2016	198,565.22	10,091	11,638	214,726	31.29	6,862
2017	1,818,876.48	31,248	36,039	2,037,480	31.37	64,950
	59,537,576.82	26,686,671	30,778,475	37,094,363		1,294,397
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
1990	4,145,218.19	1,991,110	2,173,456	2,552,093	33.66	75,820
2011	16,253,511.69	2,317,978	2,530,258	15,998,745	43.08	371,373
2012	15,127.01	1,853	2,023	15,222	43.37	351
2014	557,510.81	44,934	49,049	586,513	43.90	13,360
2015	136,494.28	7,990	8,722	146,882	44.15	3,327
2016	554,322.02	19,855	21,673	610,254	44.39	13,748
2017	304,834.06	3,698	4,037	343,474	44.62	7,698
	21,967,018.06	4,387,418	4,789,217	20,253,184		485,677
	225,669,249.55	100,287,597	104,766,988	146,729,371		6,707,279

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.9   2.97

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -10						
1972	4,720,222.42	3,964,746	4,276,341	915,903	12.96	70,672
1974	782,485.11	649,251	700,277	160,457	13.14	12,211
1975	176,219.38	145,298	156,717	37,124	13.22	2,808
1985	6,939.48	5,293	5,709	1,924	13.80	139
1986	10,096.51	7,623	8,222	2,884	13.85	208
1987	44,680.97	33,386	36,010	13,139	13.89	946
1988	88,192.17	65,199	70,323	26,688	13.92	1,917
1989	96,763.03	70,695	76,251	30,188	13.96	2,162
1993	23,071.28	15,968	17,223	8,155	14.09	579
1994	178,344.24	121,493	131,041	65,137	14.12	4,613
1996	0.30		0			
1997	1,313,417.99	847,409	914,008	530,752	14.19	37,403
1998	147,043.85	92,892	100,193	61,556	14.21	4,332
2000	6,796,392.22	4,094,024	4,415,779	3,060,252	14.25	214,755
2001	216,842.59	127,111	137,101	101,426	14.27	7,108
2004	12,633.27	6,707	7,234	6,662	14.32	465
2008	4,667.04	2,032	2,192	2,942	14.38	205
2011	261,938.32	89,188	96,197	191,935	14.41	13,320
2013	19,456.75	5,073	5,472	15,931	14.42	1,105
2015	3,149,356.34	509,528	549,573	2,914,719	14.44	201,850
2017	533,319.71	19,618	21,160	565,492	14.45	39,134
	18,582,082.97	10,872,534	11,727,023	8,713,268		615,932
MILL CREEK UNIT 1 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -10						
1983	202,167.22	157,056	220,362	2,022	13.71	147
	202,167.22	157,056	220,362	2,022		147
MILL CREEK UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -10						
1975	4,594,976.40	3,676,068	3,972,831	1,081,643	14.77	73,232
1981	19,704.77	15,021	16,234	5,442	15.30	356

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
1983	8,343.81	6,245	6,749	2,429	15.43	157
1984	66,767.91	49,469	53,463	19,982	15.50	1,289
1986	19,863.78	14,405	15,568	6,282	15.62	402
1987	1,136.02	815	881	369	15.67	24
1988	82,230.58	58,254	62,957	27,497	15.72	1,749
1989	99,084.22	69,306	74,901	34,092	15.77	2,162
1990	46,374.58	32,001	34,584	16,428	15.82	1,038
1991	78,172.89	53,182	57,475	28,515	15.86	1,798
1993	74,345.76	49,027	52,985	28,795	15.94	1,806
1994	137,636.61	89,205	96,406	54,994	15.98	3,441
1997	1,229,516.67	751,201	811,844	540,624	16.08	33,621
1998	497,415.48	297,095	321,079	226,078	16.11	14,033
2001	318,180.75	175,321	189,474	160,524	16.19	9,915
2002	32,290.53	17,241	18,633	16,887	16.21	1,042
2005	3,582.67	1,701	1,838	2,103	16.28	129
2008	12,413.17	4,995	5,398	8,256	16.33	506
2012	195,890.66	53,943	58,298	157,182	16.38	9,596
2013	74,934.03	17,694	19,122	63,305	16.39	3,862
2014	46,004.41	8,880	9,597	41,008	16.40	2,500
2015	943,364.81	136,717	147,754	889,947	16.41	54,232
2016	4,342,229.81	399,837	432,115	4,344,338	16.42	264,576
2017	222,731.66	7,235	7,819	237,186	16.43	14,436
	13,147,191.98	5,984,858	6,468,006	7,993,905		495,902
MILL CREEK UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
2015	2,694,916.35	390,561	765,601	2,198,807	16.41	133,992
	2,694,916.35	390,561	765,601	2,198,807		133,992

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1982	13,739,330.10	9,714,654	12,091,486	3,021,777	18.60	162,461
1987	9,969.82	6,628	8,250	2,717	19.10	142
1988	3,231.24	2,119	2,637	917	19.18	48
1989	392,292.18	253,441	315,449	116,072	19.26	6,027
1990	150,092.97	95,446	118,798	46,304	19.34	2,394
1991	60,001.02	37,539	46,723	19,278	19.41	993
1993	94,815.20	57,217	71,216	33,081	19.55	1,692
1994	6,239.17	3,693	4,597	2,267	19.61	116
1997	151,399.17	83,814	104,320	62,219	19.77	3,147
2007	7,967.19	2,978	3,707	5,057	20.17	251
2009	173,735.34	56,184	69,930	121,179	20.22	5,993
2012	84,503.54	19,710	24,532	68,422	20.29	3,372
2013	10,937.97	2,166	2,696	9,336	20.31	460
2014	39,504.05	6,354	7,909	35,546	20.32	1,749
2015	142,860.84	17,140	21,334	135,813	20.34	6,677
2016	11,667,104.04	875,138	1,089,253	11,744,561	20.36	576,845
2017	57,028.30	1,503	1,871	60,860	20.37	2,988
	26,791,012.14	11,235,724	13,984,708	15,485,405		775,355
MILL CREEL UNIT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1982	1,013,024.76	716,278	683,415	430,912	18.60	23,167
1993	75,852.16	45,774	43,674	39,763	19.55	2,034
2016	8,703,304.86	652,826	622,874	8,950,761	20.36	439,625
	9,792,181.78	1,414,878	1,349,963	9,421,437		464,826
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1975	610,264.79	441,864	516,606	154,685	20.12	7,688
1981	2,134,007.29	1,442,482	1,686,479	660,929	21.38	30,913
1983	429,885.94	283,238	331,148	141,727	21.72	6,525
1984	16,995,052.01	11,046,240	12,914,724	5,779,834	21.88	264,161

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 4 INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. -10						
1985	68,296.45	43,775	51,180	23,947	22.03	1,087
1986	1,536,512.19	970,205	1,134,316	555,847	22.18	25,061
1987	30,412.62	18,916	22,116	11,338	22.31	508
1988	429,640.93	263,014	307,503	165,102	22.44	7,357
1989	432,858.98	260,523	304,591	171,554	22.57	7,601
1991	89,579.56	52,024	60,824	37,714	22.79	1,655
1994	6,239.17	3,406	3,982	2,881	23.09	125
1996	14,195.63	7,387	8,637	6,979	23.27	300
1997	46,174.62	23,408	27,367	23,425	23.35	1,003
2000	70,461.55	32,630	38,149	39,358	23.56	1,671
2001	24,217.50	10,823	12,654	13,986	23.63	592
2002	106,974.51	46,010	53,793	63,879	23.69	2,696
2005	5,395.13	2,020	2,362	3,573	23.86	150
2007	8,334.63	2,770	3,239	5,930	23.95	248
2008	492,580.23	152,262	178,017	363,821	24.00	15,159
2009	58,526.04	16,670	19,490	44,889	24.04	1,867
2011	70,789.13	16,415	19,192	58,676	24.11	2,434
2012	1,135,269.23	230,003	268,908	979,888	24.14	40,592
2013	54,373.95	9,335	10,914	48,897	24.17	2,023
2014	2,354,305.36	325,582	380,655	2,209,081	24.20	91,284
2015	2,913,999.33	297,621	347,964	2,857,435	24.23	117,930
2016	23,297.30	1,493	1,746	23,881	24.25	985
2017	860,990.24	18,733	21,902	925,188	24.28	38,105
	31,002,634.31	16,018,849	18,728,455	15,374,443		669,720
MILL CREEK UNIT 4 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. -10						
2003	53,899.52	22,234	51,127	8,162	23.75	344
2014	1,613,417.17	223,123	513,074	1,261,685	24.20	52,136
	1,667,316.69	245,357	564,201	1,269,847		52,480

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 1 INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2050 NET SALVAGE PERCENT.. -14						
1990	44,621,984.19	24,283,873	26,683,021	24,186,041	28.65	844,190
1992	7,925.03	4,122	4,529	4,505	29.08	155
1993	36,015.56	18,285	20,091	20,966	29.28	716
1994	3,105,541.63	1,536,604	1,688,414	1,851,903	29.47	62,840
1996	16,791.24	7,857	8,633	10,509	29.83	352
1997	11,557.40	5,247	5,765	7,410	29.99	247
1998	51,241.29	22,523	24,748	33,667	30.15	1,117
2000	79,034.14	32,336	35,531	54,568	30.44	1,793
2001	17,727.44	6,972	7,661	12,548	30.57	410
2003	31,908.05	11,468	12,601	23,774	30.82	771
2005	22,378.23	7,228	7,942	17,569	31.04	566
2009	249,300.73	59,839	65,751	218,452	31.42	6,953
2010	119,663.51	25,950	28,514	107,903	31.50	3,425
2011	694,741.82	133,809	147,029	644,977	31.58	20,424
2013	33,727.78	4,730	5,197	33,252	31.72	1,048
2015	15,555,328.27	1,281,392	1,407,988	16,325,086	31.84	512,723
2016	145,099.43	7,384	8,114	157,300	31.89	4,933
2017	298,835.86	5,144	5,652	335,021	31.95	10,486
	65,098,801.60	27,454,763	30,167,182	44,045,452		1,473,149
TRIMBLE COUNTY UNIT 1 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2050 NET SALVAGE PERCENT.. -14						
1979	71,999.18	47,727	76,325	5,754	25.40	227
1990	2,664,921.03	1,450,285	2,319,289	718,721	28.65	25,086
	2,736,920.21	1,498,012	2,395,614	724,475		25,313
TRIMBLE COUNTY UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 65-R3 PROBABLE RETIREMENT YEAR.. 6-2066 NET SALVAGE PERCENT.. -14						
2010	34,379.96	5,540	5,989	33,204	44.71	743
2011	8,882,476.37	1,260,285	1,362,360	8,763,663	44.95	194,965
2012	1,130,271.18	138,012	149,190	1,139,319	45.18	25,217
2013	11,211.95	1,136	1,228	11,554	45.41	254

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
2014	108,078.94	8,688	9,392	113,818	45.61	2,495
2015	247,338.42	14,425	15,593	266,372	45.81	5,815
2016	206,007.20	7,320	7,913	226,935	46.00	4,933
2017	59,374.14	725	784	66,903	46.17	1,449
	10,679,138.16	1,436,131	1,552,448	10,621,770		235,871
	182,394,363.41	76,708,723	87,923,563	115,850,831		4,942,687

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.4 2.71

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
RIVERPORT DISTRIBUTION CENTER						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2063						
NET SALVAGE PERCENT.. -2						
2013	487,938.91	50,825	61,731	435,967	37.28	11,694
2016	21,052.85	759	922	20,552	38.76	530
2017	73,926.20	893	1,085	74,320	39.21	1,895
	582,917.96	52,477	63,737	530,839		14,119
MILL CREEK UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -10						
1972	325,508.28	285,570	301,827	56,232	8.94	6,290
1973	69,337.68	60,324	63,758	12,513	9.20	1,360
1981	14,471.42	11,682	12,347	3,572	11.15	320
2001	186,981.08	109,541	115,777	89,902	13.70	6,562
2003	50,572.50	27,815	29,398	26,231	13.81	1,899
2010	44,349.97	16,604	17,549	31,236	14.11	2,214
2012	17,602.50	5,314	5,617	13,746	14.17	970
2015	15,511.04	2,494	2,636	14,426	14.25	1,012
2017	312,423.29	11,393	12,042	331,624	14.29	23,207
	1,036,757.76	530,737	560,951	579,483		43,834
MILL CREEK UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -10						
1974	30,534.16	25,959	28,044	5,544	10.03	553
1977	12,631.04	10,413	11,249	2,645	10.93	242
1978	3,514.49	2,866	3,096	770	11.23	69
1979	4,222.33	3,405	3,678	966	11.52	84
1991	31,738.22	21,833	23,587	11,325	14.24	795
1998	6,708.80	4,024	4,347	3,032	15.13	200
2005	3,862.94	1,835	1,982	2,267	15.69	144
2010	9,949.34	3,419	3,694	7,251	15.96	454
2012	33,862.98	9,317	10,065	27,184	16.04	1,695
2015	4,291.92	620	670	4,051	16.15	251
	141,316.22	83,691	90,413	65,035		4,487

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -10						
1978	245,660.68	194,777	265,635	4,592	12.33	372
1980	13,104.31	10,106	13,782	632	13.10	48
1981	3,413.80	2,595	3,539	216	13.48	16
1982	3,099.18	2,321	3,165	244	13.85	18
1987	4,218.63	2,916	3,977	664	15.57	43
1991	33,921.67	21,805	29,737	7,576	16.70	454
2000	3,356.42	1,728	2,357	1,335	18.48	72
2010	9,949.34	2,945	4,016	6,928	19.56	354
2013	30,822.45	6,117	8,342	25,562	19.76	1,294
	347,546.48	245,310	334,551	47,750		2,671
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
1976	25,108.31	20,164	20,141	7,478	12.08	619
1977	6,974.10	5,520	5,514	2,158	12.53	172
1983	49,937.51	35,830	35,790	19,141	15.30	1,251
1984	135,989.65	95,801	95,694	53,895	15.76	3,420
1985	82,073.54	56,739	56,675	33,605	16.21	2,073
1986	176,507.31	119,733	119,599	74,559	16.64	4,481
1987	121,720.07	80,936	80,845	53,047	17.07	3,108
1988	136,481.52	88,908	88,808	61,321	17.49	3,506
1989	78,089.43	49,817	49,761	36,137	17.89	2,020
1990	32,896.89	20,542	20,519	15,668	18.27	858
1991	809,076.77	493,843	493,290	396,695	18.65	21,271
1992	96,062.66	57,314	57,250	48,419	19.00	2,548
1993	68,683.45	39,982	39,937	35,615	19.35	1,841
1994	235,578.67	133,774	133,624	125,512	19.67	6,381
1995	358,477.53	198,243	198,021	196,304	19.98	9,825
1996	322,994.73	173,796	173,601	181,693	20.27	8,964
1997	199,906.14	104,473	104,356	115,541	20.55	5,622
1998	49,525.85	25,108	25,080	29,399	20.81	1,413
1999	514,957.55	252,604	252,321	314,132	21.06	14,916
2000	77,551.12	36,746	36,705	48,601	21.29	2,283
2001	228,291.05	104,217	104,100	147,020	21.51	6,835
2002	157,965.40	69,293	69,215	104,547	21.71	4,816

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MILL CREEK UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
2003	701,409.79	294,424	294,094	477,457	21.91	21,792
2004	124,948.53	50,023	49,967	87,476	22.09	3,960
2005	108,210.13	41,124	41,078	77,953	22.26	3,502
2006	136,639.60	49,017	48,962	101,341	22.42	4,520
2007	122,140.23	41,079	41,033	93,321	22.57	4,135
2008	352,355.19	110,180	110,057	277,534	22.71	12,221
2009	270,140.46	77,795	77,708	219,447	22.84	9,608
2010	728,879.93	190,532	190,319	611,449	22.97	26,619
2011	506,134.20	118,342	118,209	438,538	23.08	19,001
2012	335,858.22	68,517	68,440	301,004	23.19	12,980
2013	345,692.57	59,614	59,547	320,715	23.29	13,771
2014	1,557,767.13	216,438	216,196	1,497,348	23.38	64,044
2015	216,662.05	22,277	22,252	216,076	23.47	9,206
2016	551,880.80	35,441	35,401	571,668	23.55	24,275
2017	911,778.27	19,969	19,947	983,009	23.63	41,600
	10,935,346.35	3,658,155	3,654,057	8,374,824		379,457
MILL CREEK UNIT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -10						
2005	11,565.66	4,395	12,722			
2008	9,333.18	2,918	10,266			
2009	22,312.73	6,426	24,112	432	22.84	19
	43,211.57	13,739	47,101	432		19
TRIMBLE COUNTY UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. -14						
1990	1,636,998.57	1,001,970	1,070,731	795,447	20.45	38,897
1991	123,124.08	73,276	78,305	62,057	21.03	2,951
1992	11,512.41	6,656	7,113	6,011	21.60	278
1993	4,548.23	2,553	2,728	2,457	22.15	111
1994	64,029.36	34,841	37,232	35,761	22.69	1,576
1995	84,609.07	44,562	47,620	48,834	23.22	2,103

LOUISVILLE GAS AND ELECTRIC COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2050						
NET SALVAGE PERCENT.. -14						
1996	130,300.78	66,323	70,874	77,668	23.74	3,272
1997	41,301.53	20,297	21,690	25,394	24.23	1,048
1998	29,577.96	14,003	14,964	18,755	24.71	759
1999	23,726.57	10,794	11,535	15,514	25.18	616
2000	32,185.43	14,051	15,015	21,676	25.62	846
2001	17,686.90	7,388	7,895	12,268	26.04	471
2002	139,323.17	55,507	59,316	99,512	26.45	3,762
2003	149,646.14	56,640	60,527	110,070	26.84	4,101
2004	70,762.03	25,372	27,113	53,556	27.20	1,969
2005	32,621.18	11,019	11,775	25,413	27.55	922
2006	44,964.11	14,236	15,213	36,046	27.88	1,293
2008	93,628.50	25,429	27,174	79,562	28.49	2,793
2009	35,260.57	8,746	9,346	30,851	28.77	1,072
2010	143,979.41	32,182	34,391	129,746	29.03	4,469
2013	8,704.40	1,252	1,338	8,585	29.72	289
2017	175,362.80	3,101	3,314	196,600	30.46	6,454
	3,093,853.20	1,530,198	1,635,209	1,891,784		80,052
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -14						
2011	1,783,663.47	285,974	279,179	1,754,198	37.09	47,296
2012	181,270.34	24,862	24,271	182,377	37.73	4,834
2013	274,940.16	31,130	30,390	283,042	38.36	7,379
2014	319,319.69	28,427	27,752	336,273	38.96	8,631
2015	149,819.76	9,619	9,390	161,404	39.54	4,082
2016	136,297.87	5,314	5,188	150,192	40.10	3,745
2017	683,291.74	8,911	8,699	770,253	40.63	18,958
	3,528,603.03	394,237	384,869	3,637,738		94,925
	19,709,552.57	6,508,544	6,770,888	15,127,885		619,564

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.4   3.14

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2018-00294**
ADJUSTMENT OF ITS ELECTRIC RATES	**)**	

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	**CASE NO. 2018-00295**
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	
ELECTRIC AND GAS RATES	**)**	

TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

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

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

Q. 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 in numerous proceedings before the Commission. Most recently, I testified in the Companies' 2016 base rate cases and in KU's 2017 environmental surcharge case.[1]

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to support certain exhibits required by the Commission's regulations; (2) to describe the methods by which the Companies informed their customers of the proposed rate adjustment; (3) to present the revenue effects and the bill impacts to the average residential customer; (4) to present the Companies' recommendation for the allocation of the proposed increases in electric and gas revenues among the customer classes based on the results of the Companies'

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[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371; *In the Matter of: Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Approval of Amendment to Its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2017-00483.

cost of service studies prepared by W. Steven Seelye and The Prime Group in these cases; (5) to discuss and explain the various tariff changes the Companies propose; and (6) to describe the various ways the Companies assist customers with low incomes.

I. FILING REQUIREMENTS

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001 Section 16(8)?

A. Yes, I am sponsoring the following schedules for the corresponding filing requirements for both Companies:

• Name, Address, Facts	Section 14(1)	Tab 1
• Corp. – Incorporation, Good Standing	Section 14(2)	Tab 1
• LLC – Organized, Good Standing	Section 14(3)	Tab 1
• LP – Agreement	Section 14(4)	Tab 1
• Reason for Rate Adjustment	Section 16(1)(b)(1)	Tab 2
• Certificate of Assumed Name	Section 16(1)(b)(2)	Tab 3
• Proposed Tariff	Section 16(1)(b)(3)	Tab 4
• Proposed Tariff Changes	Section 16(1)(b)(4)	Tab 5
• Statement about Customer Notice	Section 16(1)(b)(5)	Tab 6
• Notice of Intent	Section 16(2)	Tab 7
• Financial data for forecasted period presented as pro forma adjustments to base period	Section 16(6)(a)	Tab 8
• Forecasted adjustments limited to twelve (12) months immediately following suspension period	Section 16(6)(b)	Tab 9

• Capitalization and net investment rate base	Section 16(6)(c)	Tab 10
• No revisions to forecast	Section 16(6)(d)	Tab 11
• Commission may require alternative forecast	Section 16(6)(e)	Tab 12
• Testimony	Section 16(7)(a)	Tab 14
• Detailed explanation of other information provided	Section 16(7)(h)(17)	Tab 38
• Narrative description and explanation of all proposed tariff changes	Section 16(8)(l)	Tab 65
• Typical bill comparison under present and proposed rates for all customer classes	Section 16(8)(n)	Tab 67
• Customer Notice Information	Section 17	Tab 68

II. CUSTOMER NOTICE

Q. Please describe the methods by which the Companies informed their customers of their proposed electric and gas rate adjustments.

A. Notice to the public of the proposed rate adjustments is being given in accordance with the Commission's final order in Case No. 2018-00250, which approved an alternative means of providing notice of these applications and the Companies' proposed rate adjustments.[2] The Companies delivered notices of the filing of their applications, including their proposed rates, to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation through the Commonwealth of Kentucky in which customers affected reside, for publication in

[2] *In the Matter of: Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for a Declaratory Order Establishing the Form of Notice and Number of Copies of Certain Documents Filed in Support of Upcoming Applications for Rate Adjustments*, Case No. 2018-00250, Order (Aug. 31, 2018).

the applicable newspapers once a week for three consecutive weeks beginning the week ending September 28, 2018. The notices conform in form and substance to those approved in Case No. 2018-00250.[3]

In addition and in accordance with the Commission's final order in Case No. 2018-00250, the Companies took and are taking the following actions:

- On September 19, the Companies issued press advisories to all known news media organizations who cover the areas within their certified territory advising of the filing of their applications and including a hyperlink to the location on the Companies' and the Commission's websites where case documents and tariff filings will be available. The hyperlink to the Companies' website contained the same notice being published by the newspapers until September 28. On September 28, the Companies' website was updated to contain the complete public version of the applications filed with the Commission.

- On September 21, the Companies provided a copy of a full customer notice by certified mail to each public library located in KU and LG&E's service territory.

- Beginning September 24, the Companies posted at their offices and places of business a copy of the more detailed and lengthy notice that Section 17 requires, and are maintaining these postings until completion of these rate case proceedings.

- Beginning September 24, the Companies posted on their website a copy of the more detailed and lengthy notice that Section 17 requires and a hyperlink to the location on the Commission's website where case documents and tariff filings are available.

- Beginning on September 28, 2018, the Companies will include a general statement explaining their application for rate adjustments with the bills of all of their Kentucky retail customers during the course of their regular billing cycle.

- On the same day the Companies are filing these applications they are notifying by electronic mail the chief executive officer or legal counsel of each entity that was granted intervention in either or both of the Companies' most recent base-rate cases (Case Nos. 2016-00370 and 2016-00371) of the

[3] *See* Case No. 2018-00250, Application Exh. A (July 18, 2018).

filing of these applications and are providing a hyperlink to the location on the Commission's website where case documents and tariff filings are available.

- Contemporaneously with the filing of these applications, the Companies are filing the customer notice as a separate document, labeled "Customer Notice of Rate Adjustment," to enable ratepayers checking the Commission's website to easily locate the notice.

In addition, the Companies provided notice by certified mail to each special contract customer and telecommunication carrier pole attacher-licensees and to governmental units and educational institutions that attach internal communication network facilities to the Companies' poles or other facilities.

Furthermore, KU is posting the notice to the public along with a complete copy of its application for public inspection at the KU business office located at One Quality Street, Lexington, Kentucky 40507. Similarly, LG&E is posting the notice to the public along with a complete copy of its application for public inspection at the LG&E business office located at 820 West Broadway, Louisville, Kentucky 40202.

Finally, the Companies are also posting a complete copy of each application in these cases on their website (www.lge-ku.com), along with a link to the Commission's website where the case documents are available.

III. PROPOSED REVENUE INCREASES AND BILL IMPACTS

Q. Please briefly describe the revenue increases the Companies are requesting.

A. KU is requesting a 6.9 percent, or approximately $112 million, increase in its annual revenue. LG&E is requesting a 3.0 percent, or approximately $35 million, increase in its annual electric revenue, and a 7.5 percent, or approximately $25 million a year, increase in its annual gas revenue. Kent W. Blake describes in his testimony the primary drivers of the needed revenue increases.

Q. If the Commission approves the proposed base rates, what will be the percentage increases in monthly residential electric and gas bills?

A. The average monthly KU residential electric bill increase due to the proposed base rates will be 8.1 percent, or approximately $9.63, for a residential customer using an average of 1,139 kWh of electricity. Due to the expiration of the Tax Cuts and Jobs Act ("TCJA") Surcredit when new base rates go into effect, the total monthly residential electric bill increase will be 11.7 percent, or approximately $13.47, for a customer using 1,139 kWh of electricity.[4]

The average monthly LG&E residential electric bill increase due to the proposed electric base rates will be 4.1 percent, or approximately $4.23, for a residential customer using an average of 917 kWh of electricity. Due to the expiration of the TCJA Surcredit when new base rates go into effect, the total monthly residential electric bill increase will be 7.5 percent, or approximately $7.53, for a customer using 917 kWh of electricity.

The average monthly LG&E residential gas bill increase due to the proposed gas base rates will be 8.1 percent, or approximately $4.93, for a residential customer using an average of 54 Ccf of gas. Due to the expiration of the TCJA Surcredit when new base rates go into effect, the total monthly residential gas bill increase will be 12.2 percent, or approximately $7.14, for a customer using 54 Ccf of gas.

[4] By Order dated March 20, 2018, in Case No. 2018-00034, the Commission approved an Offer and Acceptance of Satisfaction providing that KU and Louisville Gas and Electric Company "will continue to impose on the bills of their customers the [TCJA Surcredit], adjusted to reflect estimated annual Tax Act benefits, until such time as new base rates resulting from applications to change base rates take effect."

Typical bill calculations for various levels of consumption are shown in Schedule N, which the Companies are providing to satisfy the filing requirement of Section 16(8)(n).

Q. How do the Companies' average electric residential rates compare to the average residential rates of investor-owned utilities across the United States?

A. The Companies work to ensure their residential customers receive reasonably priced energy. Based on the Edison Electric Institute's *Typical Bills and Average Rates Report Winter 2018*, which provides data covering the 12-month period ending December 31, 2017, KU's current average electric residential rate is approximately 23 percent lower than the average residential electric rate of investor-owned utilities across the United States. In addition, KU's overall rates for all commercial and industrial classes remain below national and regional averages with KU being 6 percent and 10 percent below such averages, respectively.

Similarly, LG&E's current average electric residential rate is approximately 18 percent lower than the average residential electric rate of investor-owned utilities across the United States. In addition, LG&E's overall rates for all commercial and industrial classes remain below national and regional averages with LG&E being 10 percent and 2 percent below such averages, respectively.

Q. Please explain how the Companies' proposed rate increases are consistent with the Companies' customer-service orientation described in Mr. Thompson's testimony.

A. The Companies work every day to provide safe, reliable, and economical utility service to our customers, as well as an excellent customer-service experience.

Therefore, as explained in Mr. Thompson's testimony, the decision to file for rate increases is a serious matter; we understand it will impact all customers and their experience with the Companies. In particular, we understand the needs of low- and fixed-income customers through our numerous engagements and relationships with these customers and their advocates. I will describe in detail later in my testimony a number of initiatives the Companies have for these customers. Our culture also includes service to the community through donations of personal and shareholder funds and through volunteering in the communities the Companies serve. So when we decide to seek additional revenues through a rate increase, we do so only when necessary to continue providing safe and reliable utility service and excellent customer service, and we do so fully cognizant of the impacts on customers resulting from our request.

Q. Please explain how LG&E's Curtailable Service Riders ("CSRs") could affect its proposed electric revenue allocation.

A. LG&E's CSRs allow eligible customers who declared interest in participating in either CSR by July 1, 2017, to begin taking service under either CSR no later than January 1, 2019. A number of customers expressed interest by the deadline but have not yet elected to begin taking CSR service. In its application, LG&E has assumed all customers that have expressed interest will begin taking CSR service no later than January 1, 2019 under CSR-2 and that they will receive the appropriate CSR revenue credits. The Companies cannot know until January 1, 2019, what those customers will actually choose. The Companies will make all necessary updates as soon as reasonably possible after the CSR elections are complete on January 1.

IV. ELECTRIC COST OF SERVICE STUDIES, RATE DESIGN, AND ALLOCATION OF INCREASE

A. Electric Cost of Service Studies

Q. Did the Companies cause to be prepared an electric cost of service study for each of the Companies to guide their proposed rate designs and the allocation of their requested electric revenue increases?

A. Yes. At my direction, Mr. Seelye and The Prime Group conducted a fully allocated and time-differentiated embedded electric cost of service study for each of the Companies.

Q. Which cost of service methodology did The Prime Group use to perform the Companies' electric cost of service study?

A. As Mr. Seelye discusses in his testimony, The Prime Group conducted the Companies' electric cost of service study using the loss of load probability ("LOLP") methodology. A utility's LOLP is the probability that a utility system's total demand will exceed its generation capacity over a given time period taking into consideration relevant factors, including the magnitude of the load and available generating capacity. Because the Companies plan their systems based largely on minimizing loss of load within reasonable economic constraints, I believe an LOLP approach to conducting a cost of service study is appropriate. For the purposes of the Companies' LOLP studies, The Prime Group used hourly LOLP to allocate fixed production costs to the classes of customers. Because the Companies plan their generating units' production on an hourly basis, an hourly LOLP calculation is sensible and appropriate.

The Companies primarily relied on the results of the cost of service studies to allocate costs between rate classes, as well as the ratemaking principle of gradualism.

Q. Please summarize the results of the electric cost of service studies.

A. The following tables (Tables 1 and 2) summarize the rates of return for each customer class before and after reflecting the rate adjustments proposed by the Companies:

TABLE 1
KU Class Rates of Return

Customer Class	Rate of Return on Rate Base	
	Actual Adjusted	**Proposed**
Residential – Rates RS, RTOD, and VFD	3.03%	4.99%
General Service – Rate GS	11.31%	13.80%
All Electric Schools – Rate AES	6.70%	8.94%
Power Service – Rate PS		
- Secondary	11.18%	13.59%
- Primary	15.22%	18.05%
Time of Day Secondary – Rate TODS	6.15%	8.20%
Time of Day Primary – Rate TODP	4.50%	6.49%
Retail Transmission Service – Rate RTS	5.77%	8.00%
Fluctuating Load Service – Rate FLS	5.05%	6.95%
Lighting Energy Service – Rate LE	21.30%	21.30%
Traffic Energy Service – Rate TE	16.53%	16.43%
Lighting and Restricted Lighting Service – Rates LS and RLS	10.48%	12.11%
Outdoor Sports Lighting Service – Rate OSL	9.47%	11.32%
Total System	5.58%	7.66%

TABLE 2
LG&E Electric Class Rates of Return

Customer Class	Rate of Return on Rate Base	
	Actual Adjusted	**Proposed**
Residential – Rates RS, RTOD, and VFD	2.69%	3.71%
General Service – Rate GS	11.74%	12.84%
Power Service – Rate PS		
- Secondary	14.44%	15.65%
- Primary	12.70%	13.94%
Time of Day Secondary – Rate TODS	9.50%	10.37%
Time of Day Primary – Rate TODP	9.52%	10.46%
Retail Transmission Service – Rate RTS	12.57%	13.72%
Lighting Energy Service – Rate LE	18.96%	18.96%
Traffic Energy Service – Rate TE	16.64%	16.63%
Lighting and Restricted Lighting Service – Rates LS and RLS	7.49%	8.07%
Outdoor Sports Lighting Service – Rate OSL	12.65%	13.52%

Special Contract	6.82%	7.94%
Total System	6.73%	7.75%

The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect all pro forma adjustments. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. Mr. Seelye discusses the actual adjusted and proposed rates of return in his testimony.

B. Allocation of Electric Revenue Increases

Q. What revenue increase is KU proposing for its operations?

A. As shown on Schedule M-2.1, KU is proposing an increase in forecasted test period revenues of $112,459,859, which is calculated by applying the proposed rates to forecasted test period billing determinants and including changes to miscellaneous operating revenues. This increase is less than the revenue deficiency of $112,663,325 shown in Schedule A because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule and the adjustment for the imputed revenues for the Solar Share and Electric Vehicle programs discussed in the testimony of Mr. Seelye.

Q. What revenue increase is LG&E proposing for electric operations?

A. As shown on Schedule M-2.1-E, LG&E is proposing an increase in electric forecasted test period revenues of $34,887,485, which is calculated by applying the proposed rates to forecasted test period billing determinants and including changes to miscellaneous operating revenues. This increase is less than the revenue deficiency of $34,975,012 shown in Schedule A for electric operations because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule and the adjustment for the imputed revenues for the Solar Share and Electric Vehicle programs discussed in the testimony of Mr. Seelye.

Q. How do the Companies propose to allocate the electric revenue increase to the classes of service?

A. On average, KU proposes to increase revenue across its rate classes by a system average of approximately 7.1 percent, and LG&E proposes to increase electric revenue across its rate classes by a system average of approximately 3.1 percent. But the results of the Companies' cost of service studies show there are notable differences in the rates of return between the Companies' electric rate classes. This means there are some rate classes that are effectively subsidizing other rate classes. Although the Companies do not propose to eliminate all interclass subsidies in this proceeding, the Companies do propose generally to recover larger relative portions of the overall revenue increase from rate classes with lower rates of return and smaller relative portions of the proposed revenue increase from rate classes with higher rates of return.

In the Companies' class cost of service studies, as shown in Tables 1 and 2 above, the residential rate classes have the lowest rates of return on rate base of any major rate class. For this reason, I agree with Mr. Seelye's recommendation for an increase of one percentage point above the overall increases to be applied to the residential rate classes in order to address the class subsidies consistent with the principle of gradualism. Of course, the residential rate classes will still remain well below the system average rate of return on rate base.

In addition, the Companies recognize the importance of economic development and of manufacturing to the economic health of the Commonwealth. The Companies took those considerations into account when formulating their proposed revenue allocations in these proceedings, recognizing that utility rates are important to both economic development and the ongoing vitality of manufacturers already located in the Companies' service territories. For these reasons, I agree with Mr. Seelye's recommendation that the large customer rates should receive an increase that is one percentage point below the overall increases for KU and for LG&E, because these rate classes indicate higher rates of return than the residential customer classes.

Finally, because Rates LE and TE currently have high rates of return on rate case and the revenues collected from these two rates are relatively small, I agree with Mr. Seelye's recommendation to have no increase allocated to those rate classes.

The Companies are therefore generally proposing higher percentage increases for rate classes that have low rates of return, and the Companies are proposing lower percentage increases for rate classes that have higher rates of return. This approach supports economic development and manufacturing, comports with the longstanding ratemaking principle of gradualism, and is consistent with the Companies' past rate-allocation proposals where there have been significant differences in rates of return between rate classes. Mr. Seelye further discusses this approach in his testimony.

C. <u>Electric Rate Design Approach</u>

Q. What is the basic objective of the rate design being proposed?

A. The Companies' proposed rate design continues to bring both the structure and the charges of the rate design in line with the results of the cost of service studies. One global change the Companies are proposing is to move from a monthly Basic Service Charge to a daily Basic Service Charge, which permits more accurate cost recovery for each billing period (not all billing periods have the same number of days) and avoids any need to prorate service for customers who begin or end service mid-billing period.

The Companies are also adding a new Green Tariff to allow customers desiring to make renewable energy a part of their energy supply from the Companies to do so. The Companies believe this offering addresses an interest among existing customers and will serve to make their service territories more attractive to businesses seeking to locate new facilities in the Commonwealth and who have their own sustainability goals.

In addition, the Companies are proposing several notable changes to existing rate schedules and charges, including splitting the energy charge into two components for informational purposes on the tariff sheets for rate schedules that do not have demand charges and to move Rate TODS to be billed on a kVA basis instead of kW. My testimony addresses changes the Companies are proposing to rate structures and the charges supported by the cost of service study.

D. <u>Residential Electric Rate Design and Increase</u>

Q. Do the Companies propose to change their Residential Service (Rate RS) rate structure?

A. No. The rate structure will remain the same and consist of a Basic Service Charge and a flat volumetric, per-kWh energy charge, although the Basic Service Charge will now be a daily rather than monthly charge. Also, as I discuss below, the Companies are separating the energy charge into two components solely on the tariff sheets—not on customers' bills—for Rate RS and a few other rate schedules to inform customers, stakeholders, and employees about the two kinds of costs (fixed and variable) recovered through the Companies' volumetric energy charges.

Q. Do the Companies propose to bring the rate components in residential electric rates more in line with their cost of service studies?

A. Yes, although on a gradual basis. The Companies are proposing a daily Basic Service Charge of $0.53 for Rates RS, RTOD-Demand, RTOD-Energy, and Volunteer Fire Department Service (Rate VFD), which is equivalent to a monthly Basic Service Charge of $16.13. The proposed charges are increases from the Companies' current monthly residential Basic Service Charge of $12.25. As Mr. Seelye discusses in his testimony, KU's electric cost of service study indicates that the customer-related cost for the residential class is $23.89 per customer per month ($0.78 per day), and LG&E's electric cost of service study indicates that the customer-related cost for the residential class is $20.34 per customer per month ($0.67 per day). The Companies are therefore proposing to increase their residential Basic Service Charges in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost. This cost is discussed more thoroughly in Mr. Seelye's testimony and is derived in his Exhibit WSS-2 for each of the Companies.

Q. Would recovering a larger proportion of customer-specific fixed cost through the Basic Service Charge rather than through the energy charge (or demand

charge for Rate RTOD-Demand) have the effect of stabilizing customers' monthly bills?

A. Yes. Increasing the Basic Service Charge will reduce the spikes that customers see in their bills during high-usage months and cause customer bills to be somewhat more level throughout the course of a year. Unexpected surges in utility usage caused by extreme weather conditions can create additional hardships for customers who already have difficulty paying their utility bills in high-usage seasons and can cause other customers to have difficulties for the first time. Increasing the Basic Service Charge to more closely align with customer-specific fixed costs will reduce the amount of fixed costs embedded in energy rates.

Q. What changes do the Companies propose to make to Rates RS, RTOD-Energy, RTOD-Demand, VFD, and General Service (Rate GS)?

A. For Rates RS, RTOD-Energy, RTOD-Demand, VFD, and GS, the Companies are proposing to split the energy charge into two components—fixed-cost recovery and variable-cost recovery—on the tariff sheets for informational purposes. The Companies do not propose to bill customers two separate energy charges related to the two kinds of cost recovery or to show the two components on customers' bills at this time. Rather, splitting the energy charge solely on the tariff sheets as proposed will allow stakeholders and interested customers to see how much fixed-cost recovery versus truly variable-cost recovery is embedded in the Companies' volumetric energy rates for those rate schedules. Such a change will allow for the variable-cost recovery component for all rate schedules to be shown in the tariff sheets.

Q. Please explain further the difference between the Companies' fixed and variable costs of providing electric service and why splitting the energy charge on certain tariff sheets better reflects those costs.

A. The utility industry, and especially the electric utility industry, is a highly capital-intensive business that requires the purchase, operation, and maintenance of large capital assets—fixed costs—to produce a product with comparatively low variable costs per unit (mostly fuel). The large capital assets include generating units (and associated environmental facilities) to make electricity, transmission facilities to move the electricity in bulk and over long distances, and distribution facilities to move the electricity at lower voltages and over shorter distances to the Companies' customers. Also included in fixed-cost assets are the Companies' meters, customer-service and administrative facilities, operations and maintenance facilities and vehicles, and numerous other assets required simply to have an electric utility available for customers to use at all times. The Companies choose the appropriate capacities for their various assets based on customers' demands on the total system: generation, transmission, and distribution. Because it is uneconomical to store large quantities of electricity to meet fluctuations in customers' collective demand, the Companies must size their facilities to be ready to meet the considerable demand hundreds of thousands of residential, commercial, and industrial customers can place on the Companies' system, all without prior notice: customers expect electricity to be available instantaneously and in any quantity. To provide that kind of service safely, reliably, and economically requires large investments in capital assets and ongoing fixed operations and maintenance expenditures just to ensure service is available for customers even when they choose not to use much of it at any given time.

But the truly variable cost of providing any given unit of electricity is relatively small. Indeed, compared to the fixed costs of the facilities and people necessary to ensure the ability to produce any electricity, the variable cost of producing a unit of electricity (i.e., fuel and other consumables) is quite small, about three cents per kWh according to Mr. Seelye's cost of service study.

Therefore, looking at the Companies' actual costs, three basic categories of costs emerge naturally: a portion of fixed costs that do not vary with demand, fixed costs that are related to demand, and variable cost; these are the categories Mr. Seelye addresses in his testimony and cost of service studies. And most of the Companies' standard rate schedules have rate structures that reflect these three categories of costs: a fixed Basic Service Charge to collect customer-specific and demand-invariant fixed costs; a demand charge to collect demand-variant fixed costs that is expressed in dollars per kW or kVA of instantaneous demand; and a relatively low energy charge of a few cents per kWh for energy consumed irrespective of demand, which recovers base fuel and other consumable costs of providing energy. Such rate schedules follow basic principles of cost causation by having charges reflect the Companies' underlying costs.

But the Companies also have a number of rate schedules that do not have a demand charge. Therefore, the Companies' rate schedules that do not have a demand charge (Rates RS, RTOD-Energy, VFD, and GS) recover significant amounts of the Companies' fixed costs of serving customers through the schedules' volumetric energy rates. For example, KU's Rate RS currently has an energy rate of $0.09047 per kWh, and LG&E's electric Rate RS currently has an energy rate of $0.09382 per kWh. The Companies' truly variable cost of producing a kWh of electricity (primarily fuel cost) is about $0.03 per kWh; the remaining charge per kWh provides the Companies fixed-cost recovery that the Rate RS Basic Service Charge does not cover. But as I discussed above, the Companies incur fixed costs regardless of whether customers actually consume any energy. As discussed in the testimony of Mr. Seelye and as I noted above, the production facilities, transmission and distribution lines, transformers and other facilities, as well as the Companies' personnel, must be in place at all times for customers to receive energy instantaneously when they desire to cool or heat their homes, turn on their lights, power their computers, or watch television. The costs of these facilities and personnel are fixed relative to energy consumption. To the extent the Companies do not recover such costs through Basic Service Charges, they must recover them through the volumetric energy charge for rate classes that lack a demand charge, which can result in intra-class subsidies.

The Companies are therefore proposing in this proceeding to split the energy charge into fixed-cost (Infrastructure Energy Charge) and variable-cost (Variable Energy Charge) components for Rates RS, RTOD-Energy, RTOD-Demand, VFD, and GS. The Companies believes this approach will help inform the customers, stakeholders and employees about the amount of fixed-cost recovery inherent in the energy charge for these rate schedules, enabling a better understanding of intra-class subsidies, and more generally the nature of the charges customers pay. Such a change on the non-demand rate schedules will allow for the Variable Energy Charge to be consistently shown for all rate schedules.

V. OTHER ELECTRIC RATE AND TARIFF CHANGES

A. <u>Standard Rate Schedule TODS</u>

Q. What change does the Companies propose to make to Standard Rate Schedule TODS?

A. The Companies propose to change the demand billing for Rate TODS to be on the basis of kVA instead of kW. Over the last several base rate proceedings, the Companies have transitioned the large commercial and industrial customer's rate schedules to kVA billing. Rate TODS is the last of these schedules to be transitioned to kVA billing.

B. <u>Late Payment Charges</u>

Q. What is the Companies' proposal regarding late payment charges?

A. The Companies propose to waive a residential customer's late payment charge if the customer requests it and has not incurred a late payment charge in the previous eleven billing cycles. In other words, the Companies propose to permit only one such waiver per twelve billing cycles. This would allow residential customers who ordinarily pay on time but occasionally pay late not to be charged while retaining a general incentive for customers to pay on time.

C. <u>Green Tariff</u>

Q. Please describe the Companies' new Green Tariff.

A. The Companies are adding a new Green Tariff to each of their electric tariffs to ensure that businesses inside and outside Kentucky know that the Companies have multiple renewable offerings. The new Green Tariff provides three options for customers seeking to support the development of renewable energy resources.

The first option is the continuation of the Companies' existing Small Green Energy and Large Green Energy programs (Riders SGE and LGE), which the Companies propose to remove from their tariffs as separate riders and incorporate into a single option under the new Green Tariff. None of the pricing or substantive terms of the existing Riders SGE and LGE will change in Green Tariff option 1.

The second option in the new Green Tariff is the Business Solar option. This option will continue and formalize as a tariff offering the Companies' existing Business Solar program. The program is for non-residential customers seeking to have solar facilities constructed and owned by the Companies. The Companies arrange for the design, installation, and ongoing operation and maintenance of the facilities. Business Solar customers receive two significant benefits: (1) the benefit of additionality, i.e., causing entirely new solar facilities to be constructed, and (2) the benefit of receiving the value of the facilities' output.

The Companies plan that Green Tariff option 2 will build on the success of the existing Business Solar program, under which LG&E successfully engaged with the Archdiocese of Louisville to install a solar array on the premises of the Archdiocese. As with the Business Solar arrangement LG&E has with the Archdiocese, the Companies will require a contract with a customer under the Business Solar option to obtain reasonable assurances of cost recovery, and will file all such contracts with the Commission.

The third Green Tariff option will allow customers to engage with the Companies to consider entering into renewable energy purchase agreements to supply some or all of a customer's energy needs. To be eligible for option 3, a customer must have load of 10 MVA or more and be willing to enter into an obligation for 10 MW or more of new (not already existing) renewable capacity. The energy from the new renewable facility must be delivered to the Companies' transmission system. The minimum term of the contract into which the customer must enter with the Companies is five years and is equivalent to the term of the agreement with the renewable energy provider. The Companies will file all such contracts with the Commission. The Companies propose to limit this offering to 50 MW for each of the Companies, i.e., no more than 100 MW total, which should be absorbable in the Companies' system without material integration issues.

D. <u>Removal of School Power Service (Rate SPS) and School Time-of-Day Service (Rate STOD); Retention of Outdoor Sports Lighting Service (Rate OSL)</u>

Q. Why have the Companies removed Rates SPS and STOD from their electric tariffs?

A. The Companies added Rates SPS and STOD to their tariffs as pilot rates in accordance with the April 19, 2017 Stipulation and Recommendation in the Companies' most recent rate cases. The Commission's June 22, 2017 orders in those proceedings approved the pilot rates, but limited the time they could remain in effect: "[T]he Commission will place a limit on the amount of time the pilot tariffs will be in effect and finds that the pilot tariffs should be effective for three years, or until LG&E

files its next rate case, whichever is earlier."[5] Effective with the filing of this application, the Companies moved all schools served under Rates SPS and STOD to their appropriate standard rate schedules, and have not included the pilot rate schedules in their proposed electric tariffs.

Q. Will the Companies retain Rate OSL as a pilot rate?

A. Yes. As Mr. Seelye addresses in his testimony, it appears at this point that Rate OSL has a cost-of-service justification. The Companies therefore propose to retain Rate OSL as a pilot rate in this proceeding.

E. Changes to Lighting Service and Restricted Lighting Service

Q. Please explain the changes shown on Sheet Nos. 35 – 35.3 concerning Lighting Service (Rate LS) and on Sheet Nos. 36 – 36.3 concerning Restricted Lighting Service (Rate RLS).

A. The Companies propose to move all non-LED lighting offerings to Restricted Lighting Service with the exception of Victorian High Pressure Sodium fixtures for both Companies and London High Pressure Sodium fixtures for LG&E (KU does not offer London fixtures); only those customers already participating in those non-LED offerings will be able to continue to receive service for those lights. These two limited exceptions do not have comparable LED lighting alternatives. The Companies will continue to provide fixtures and poles for non-LED lights as existing fixtures and poles need to be replaced, but will do so only from the Companies' existing inventory. When those inventory items are exhausted, a lighting customer whose

[5] Case No. 2016-00370, Order at 20 (June 22, 2017); Case No. 2016-00371, Order at 23 (June 22, 2017).

non-LED fixture or pole needs to be replaced will need to convert to a new LED fixture, pole, or both under Rate LS.

With regard to Rate LS, the Companies have significantly expanded the LED offerings available. Offerings of poles and fixtures are available for those with underground wiring for lighting, and fixture-only offerings are available for overhead lighting service. These expanded LED offerings arise in part due to the work the Companies have done with the LED Collaborative group since their most recent rate cases.

Customers desiring to convert their existing non-LED lighting under current Rate LS or RLS to new LED lighting under the proposed Rate LS will be able to do so by paying the conversion fee set out in Rate LS. That fee is designed to recover the undepreciated book value of a customer's non-LED fixture.

F. <u>Changes to Pole and Structure Attachment Charges (Rate PSA)</u>

Q. Briefly describe the background of Rate PSA.

A. Prior to July 1, 2017, the Companies' pole attachment services were provided primarily through the Companies' Cable Television Attachment Charges ("Rate CTAC"). Rate CTAC established the terms and conditions under which a cable television ("CATV") service provider could attach its facilities to the Companies' poles. Rate CTAC was not available to other entities, such as telecommunication carriers. Instead the Companies entered into license agreements with those entities that set forth the terms and conditions for making attachments to the Companies' poles.

In its last rate case proceedings, the Companies proposed significant revisions to Rate CTAC to reflect the technological advancements in the facilities being attached to the Companies' poles. The Companies proposed to define "attachment" to expressly include wireline and wireless facilities of telecommunication carriers, to clarify the application and permit process for attachments, and to detail the construction and maintenance requirements and specifications for attachments. These changes were reflected in their proposal to rename Rate CTAC to "Pole and Structure Attachment Charges" (Rate PSA). In addition to expanding the availability of attachment services, the proposed revisions contained several measures to reduce the likelihood of electric reliability concerns resulting from a pole attachment. While intervening parties voiced some concerns with these revisions, they and the Companies entered into settlement agreements that incorporated most of the proposed revisions, which the Commission ultimately approved. Rate PSA became effective on July 1, 2017.

Q. Are the Companies proposing revisions to Rate PSA in these proceedings?

A. Yes. The major revision that the Companies propose to Rate PSA is expanding the availability of the schedule to governmental units and educational institutions.

Q. How are "governmental unit" and "educational institution" defined?

A. Under the proposed revision, a "governmental unit" includes any agency or department of the Federal Government; a department, agency or other unit of Kentucky State Government; and any county, city, special district or other political subdivision of the Commonwealth of Kentucky. An "education institution" is defined as any public or private, non-profit university, college or community college.

Q. Would this revision permit a governmental unit or educational institution to attach its facilities to the Companies' poles?

A. Yes, it would permit a governmental unit or education institution to place attachments on the Companies' poles. "Attachment" as defined in the PSA Schedule is limited to certain types of cables and to equipment used to provide wireless communication services and to transmit or receive radiofrequency signals. The proposed revision would, for example, address the efforts of a city government or a college to attach fiber cable and related facilities to the Companies' poles to connect its buildings and structures that are dispersed throughout an area. Previously that city government or college could not have accessed the Companies' poles without first entering a license agreement with the Companies.

The proposed revision does not affect attachments for municipal CATV systems or municipal "for public" internet service systems since the operation of such system would place the city within the definition of "cable television system operator" or "telecommunications carrier" and make it eligible for service under the existing Rate PSA. Please also note that the Companies' Rate TE (Traffic Energy Service) already addresses the attachment of traffic control devices including, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, and emergency sirens.

Q. Why are the Companies making this proposal?

A. The Companies have received requests from governmental units and educational institutions to place their attachments on the Companies' poles to support their internal communications networks. The Companies have entered license agreements with some of these entities to permit the attachments. The Companies believe that including these types of facilities under Rate PSA will ensure fair and uniform treatment for all attachments and will make the Companies' administration of attachment services for these types of facilities easier and less costly.

Q. How will the Companies address existing licensing agreements for the attachment of these types of facilities?

A. Because the Companies do not have a tariff that addresses the attachment of these types of facilities, they have executed license agreements with some governmental units and educational institutions. Because the license agreements were executed at different times, the license agreements have different expiration dates. Once a license agreement expires, if that governmental unit or educational institution wishes to continue attaching facilities to the Companies' poles and falls within the availability of service, it must then take service under Rate PSA. The customer will then execute an agreement that incorporates the terms of service under the PSA rate schedule. More recently, the Companies have proposed license agreements that incorporate most of the terms of Rate PSA and provide for termination of the agreement if the governmental unit or education institution becomes eligible to make attachments under Rate PSA.

Q. Will certain types of attachments continue to be excluded from the revised rate schedule?

A. Yes. The facilities of incumbent local exchange carriers with joint use agreements with the Companies, facilities subject to a fiber exchange agreement, and macro cell facilities will continue to be excluded from Rate PSA due to their unique nature and pricing arrangements. As new agreements are made, these attachments will be governed by special contracts that will be filed with the Commission.

Q. Are there proposed changes to the attachment fees?

A. No. As Mr. Seelye discusses in his testimony, the current charges remain reasonable, so the Companies are not proposing to change them in this proceeding.

Q. What other provisions, if any, are the Companies proposing for Rate PSA?

A. The Companies have proposed several revisions to reduce the Companies' risk exposure from non-Company attachments attaching under Rate PSA. The Companies propose to increase the minimum coverage limits for certain types of liability insurance coverage that an attachment customer must retain as a condition for attachment.

To ensure the payment of charges, inspections and other work the Companies must perform under Rate PSA for an attachment customer, the Companies propose to increase performance assurance requirements and to expand the types of security acceptable as performance assurance. Currently the Rate PSA requires either a cash deposit or surety bond. The Companies also propose revisions to simplify how the amount of performance assurance that the attachment customer must provide is determined and administered.

The Companies further proposes that attachment customers be required to reimburse the Companies for the cost of any audit of pole attachments. The Companies plan to conduct audits to confirm the number of attachments that each attachment customer has made to their facilities. The audits will ensure that attachment customers are accurately billed for the services that they receive and that attachment customers are observing the application and permitting procedures presently contained in Rate PSA. The cost of such audits is not included in the attachment charge. Upon completing any audit, the Companies would submit an invoice for the audit's cost to the attachment customer. If more than one attachment customer's facilities are within the audit's scope, then the cost of the audit will be prorate among the attachment customers subject to the audit.

The revised Rate PSA also contains a penalty of $25 per attachment for unauthorized attachments found as a result of an audit. This penalty is in addition to any attachment charges owed for the period of the unauthorized attachment, presumed to be two years. The Companies believe that this modest penalty is the only practical means to enforce application and permitting procedures presently contained in Rate PSA and to discourage willful violations of those procedures. Currently, the only means of enforcement is the removal of the unauthorized attachment. Given the potentially disruptive effect of such action on the customers of the CATV or telecommunications provider's service, removal of the attachment is not a realistic deterrent to unauthorized attachments.

The Companies are also proposing some additional safety and operational related revisions. The revised tariff will prohibit the installation of any attachment that causes interference with the Companies' wireless facilities. It will permit any person authorized to work on a Company pole to temporarily disable a wireless facility attached to the pole to permit the performance of the work. Previously only the Companies and other attachers, but not emergency responders, could disable the facility to perform work on the pole.

The revised Rate PSA will also allowed the Companies to assess an attachment customer 150 percent of the cost of repairs in instances in which an attachment customer fails to properly install its facilities and then fails to take timely corrective action after the Companies have notified the attachment customer of the non-compliant installation. Improperly installed attachments typically constitute violations of the National Electrical Safety Code and pose a safety hazard for electric and communications workers. This portion of the charge in excess of cost is intended to provide an incentive for attachment customers to timely correct defective, non-standard conditions that threaten the facilities of the Companies and other attachers and that may also threaten the public safety and the reliability of electric service.

Q. Please describe the Companies' changes to Electric Vehicle Charging Service (Rate EVC).

A. The Companies are proposing to create a charge rate for the first two hours that is lower than the rate for subsequent hours of charging. The Companies further propose to base the rate for electric vehicle charging to be approximately equivalent to a comparable amount of gasoline. This approach makes electric vehicle charging at public charging stations more attractive to customers while also ensuring the Companies recover at least their variable cost of generation for energy supplied. Mr. Seelye further addresses these changes to Rate EVC in his testimony.

Q. Please describe the Companies' proposed changes to their Special Charges at Sheet No. 45.

A. The Companies are proposing to reduce the returned payment charge from $10.00 to $3.00, as well as to increase the electric meter pulse charge from $15.00 to $25.00 per month. Mr. Seelye discusses these changes and sponsors the cost support for them.

G. Changes to Riders

Q. Please describe the Companies' changes to the Temporary/Seasonal Service Rider (Rider TS) at Sheet Nos. 66 – 66.1.

A. First, the Companies are renaming Rider TS to "Temporary-to-Permanent and Seasonal Service." As is reflected in the revised Availability section, part of the purpose for changing the name of the rider is to reflect the availability of service for temporary service that is intended to lead to the installation of permanent service delivery points.

Second, the Companies propose to extend the term of service permissible under Rider TS from the current limit of one year to up to three years for two types of customers: (1) those with demand over 50 kW, provided for construction purposes, and where in the judgment of the Companies the local and system electrical facility capacities are adequate to serve the load without impairing service to other customers; and (2) customers needing temporary intermittent use of the Companies' facilities, where the Companies have facilities they are willing to provide to allow customers to install and operationally test the customers' equipment.

Third, the Companies propose to revise the provisions governing the connection and facilities costs customers pay under Rider TS to better reflect the nature of temporary-to-permanent service. Where such service is required to construct permanent delivery points for residences and commercial buildings, the Companies will provide temporary electric service upon request for a non-refundable charge. The charge will be subject to annual review and revision and will depend on the facilities to be installed (and possibly removed) to connect service. The

Companies propose a standard charge of 15% of the estimated installation and removal cost where the facilities to provide service are already in place.

Fourth, for truly seasonal service, i.e., where facilities are installed for temporary service that will not be utilized as part of a future permanent service, customers are required to pay for all costs of making temporary connections, as well as the cost of removing such facilities when service ends.

Fifth, the Companies propose to add text to clarify that temporary services for underground or overhead installations must be constructed to the Companies' standards, with the customer to furnish and install all necessary materials and equipment. In addition, the customer must contact the Companies for removal when the temporary service is no longer needed.

Sixth and finally, where the Companies are providing temporary service under a contract with a refundable facilities deposit, the Companies will refund the deposit after three years of continuous service.

Q. Please describe the proposed changes to the Economic Development Rider (Rider EDR) at Sheet Nos. 71 – 71.3.

A. The Companies propose to restructure the incentives available to customers eligible for Rider EDR. Today, a customer receiving savings under Rider EDR receives 50% off of the customer's demand charges in the first contract year, 40% off in the second contract year, and so on down to 10% off in the fifth contract year. The Companies propose to allow a Rider EDR customer to receive the same demand-charge discount levels for the first five years of the Rider EDR contract, but to do so in whatever order the customer desires (e.g., 10%, 50%, 40%, 30%, and 20%). This would allow the customer to maximize the value of the savings and create additional economic development incentive while still ensuring the Companies' other customers are not harmed.

With regard to the Brownfield Development portion of Rider EDR, the Companies propose to make the rider available to customers with minimum billing demands of 500 kVA and to require a load factor of at least 50%. The latter requirement will help ensure customers qualifying for Rider EDR under this provision have a load that is reasonably close to the contract demand qualifying the customer for the rider and its demand-charge savings.

With regard to the Economic Development portion of Rider EDR, the Companies propose to make the rider available to customers with minimum billing demands of 1,000 kVA and to require a load factor of at least 50%. The latter requirement will help ensure customers qualifying for Rider EDR under this provision have a load that is reasonably close to the contract demand qualifying the customer for the rider and its demand-charge savings.

The Companies propose also to add a new means of qualifying for Rider EDR, namely Economic Redevelopment. Under the Economic Redevelopment part of Rider EDR, service will be available to customers locating at vacant commercial or industrial properties that have been unoccupied for at least twelve months. Such a customer must have a minimum monthly billing demand of 500 kVA, have a minimum load factor of 50%, and take service from the existing electrical infrastructure at the redevelopment site. A customer relocating operations from another premise within KU's or LG&E's service territory and maintaining the same demand load as indicated on the customer's Load Data Sheet would be ineligible for the rider, though such a customer could be eligible if it increased demand by at least 500 kVA minimum and had at least a 50% load factor.

Finally, the Companies propose to add a condition to Rider EDR that the rider is not available to a new customer that results solely from a change in ownership of a previous customer‘s account. But if a change in ownership occurs after the previous customer had entered into an EDR special contract, the successor customer may be allowed to fulfill the balance of the EDR special contract.

Q. Please describe the Companies' changes to the Solar Share Program Rider.

A. Under the Companies' current Solar Share Program Rider, there is only one way to subscribe to capacity in Solar Share Facilities, namely to pay a monthly subscription fee. The Companies propose to give customers the option to pay a one-time subscription fee that entitles the subscriber to 25 years of benefits from the subscribed capacity. This one-time fee is conceptually similar to the subscription approach the Commission approved for East Kentucky Power Cooperative, Inc.'s community solar program.[6] The Companies propose that a customer subscribing to capacity by paying the one-time fee be allowed to transfer that subscription to another customer taking service from the same Company, e.g., a KU customer may transfer a subscription to another KU customer, but not to an LG&E customer.

As Mr. Seelye addresses at length in his testimony, the Companies are proposing a reduced monthly subscription fee for Solar Share in these proceedings, which results from calculating the charge on a levelized basis. As Mr. Seelye further

[6] *See* East Kentucky Power Cooperative, Inc., PSC No. 35, Original Sheet No. 32 (effective Nov. 2, 2017).

discusses, the Companies are imputing additional revenues to Solar Share to offset the effect of the reduced charge, which ensures other customers are not adversely affected by levelizing the monthly charges, even in the short run.

The Companies are also proposing to revise the nature of the Solar Energy Credits associated with the Solar Share Program. The Companies are proposing that a subscribing customer will receive the benefit of having the customer's electrical consumption matched with the pro rata energy production from the Solar Share Facilities every 15 minutes. For each 15-minute matching period, if the customer's energy consumption is greater than or equal to the customer's pro rata energy production, the customer will be billed for the net consumption during that period at the applicable standard tariff rates. If the customer's energy consumption is less than the customer's pro rata energy production for that period, the customer will receive a dollar-denominated bill credit for the net energy produced, with each net kWh valued at the non-time-differentiated rate for Standard Rate Rider SQF, (Small Capacity Cogeneration and Small Power Production Qualifying Facilities). Any bill credits in excess of the other rates and charges the customer incurred in a billing period would carry forward to the next billing period. To ensure that the Companies can accurately calculate and provide these benefits to participating customers, each customer subscribing to Solar Share will receive an advanced meter, which is capable of registering usage in 15-minute increments.

H. <u>Changes to Adjustment Clauses</u>

Q. Why do the Companies propose to discontinue the surcredits they currently provide under Adjustment Clause TCJA at Sheet No. 89?

A. Adjustment Clause TCJA states, “The TCJA Surcredit shall terminate when base rates are changed following an application requesting a change in base rates.” This provision is reasonable because the rates resulting from this proceeding will account for the effects of the Tax Cuts and Jobs Act on a going-forward basis, negating the need for the adjustment clause to ensure customers receive the benefits of the tax savings the act created.

Q. Please explain the text change the Companies propose to make to Adjustment Clause FF (Franchise Fee) at Sheet No. 90.1.

A. The Companies have added text to clarify that they will not calculate or collect any franchise fees, taxes, or charges pursuant to expired, lapsed, or otherwise invalid, ineffective or inapplicable ordinances, franchise agreements, or other governmental enactments.

I. Other Tariff Changes

Q. Please explain the text change the Companies propose to make to their Line Extension Plan at Sheet No. 106.1.

A. The Companies propose to make changes to their Normal Line Extensions and Other Line Extensions provisions that will allow the Companies to reduce financial burdens on certain customers requiring distribution line extensions of more than 1,000 feet or who may require poly-phase service or whose installed transformer capacity will exceed 25 kVA. For such customers, the Companies propose to provide such a requested line extension at no cost to the customer, but only to the extent that the cost of the requested extension does not exceed the lesser of (a) the cost of a comparable overhead extension (if an underground extension is requested) or (b) five times the customer’s estimated annual net revenue, where “net revenue” is defined as the customer's total revenue less base fuel, Fuel Adjustment Clause, Off-System Sales, Demand Side Management charges, franchise fees, and school taxes. This should help ensure that customers requiring such extensions can obtain them at a reasonable upfront cost while also providing protections to other customers by capping the amount the Companies will invest in any such extension.

Q. Have the Companies made any other changes to their electric tariffs?

A. Yes. The Companies have made a number of small edits to clarify certain issues and make clean-up edits throughout their tariffs.

VI. GAS COST OF SERVICE STUDY, RATE DESIGN AND ALLOCATION OF INCREASE

A. <u>Gas Cost of Service Study</u>

Q. What methodology did LG&E use in its gas cost of service study?

A. In general, the methodology used followed the electric cost of service study; however, the gas cost of service study is not time-differentiated. This methodology for the gas cost of service is consistent with prior rate cases except that a refinement has been made in the way that transmission costs are allocated in the study. The details of that study are presented in the testimony of Mr. Seelye.

Q. Please summarize the results of the gas cost of service study.

A. The following table (Table 3) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by LG&E:

TABLE 3
Gas Class Rates of Return

Customer Class	Actual Adjusted Rate of Return	Proposed Rate of Return
Residential – Rate RGS and VFD	4.46%	6.81%
Commercial – Rate CGS	6.21%	9.14%

Industrial – Rate IGS	16.70%	16.70%
As-Available Service – Rate AAGS	101.95%	101.95%
Firm Transportation Service – Rate FT	15.79%	15.79%
Total System	5.34%	7.75%

The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect all pro forma adjustments. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. Mr. Seelye discusses the actual adjusted and proposed rates of return in his testimony.

B. <u>Allocation of Gas Revenue Increase</u>

Q. What revenue increase is LG&E proposing for gas operations?

A. As shown on Schedule M-2.1-G, LG&E is proposing an increase in gas forecasted test period revenues of $24,924,874, which is calculated by applying the proposed rates to forecasted test period billing determinants. This increase is slightly lower than the revenue deficiency of $24,925,739 shown in Schedule A for gas operations because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule.

Q. How does LG&E propose to allocate the gas revenue increase to the classes of service?

A. LG&E proposes to recover the revenue increase from the rate classes with the lowest rates of return, i.e., Rates RGS, VFD, CGS, and SGSS, via equal percentage revenue increases to those classes. This approach mitigates, but does not eliminate, all interclass subsidies in this proceeding. Mr. Seelye further discusses the details of his study in his testimony that supports this approach.

C. Change to Gas Basic Service Charges

Q. What change is LG&E proposing to make to its gas Basic Service Charges for Rates RGS, VFD, CGS, and IGS?

A. As with LG&E's electric Basic Service Charges, the change LG&E proposes for these gas rate schedules only is to move from a monthly Basic Service Charge to a daily Basic Service Charge, which permits more accurate cost recovery each billing period (not all billing periods have the same number of days) and avoids any need to prorate service for customers who begin or end service mid-billing period.

D. Late Payment Charges

Q. What is LG&E's proposal regarding late payment charges?

A. LG&E proposes to waive a residential customer's late payment charge if the customer requests it and has not incurred a late payment charge in the previous eleven billing cycles. LG&E proposes to permit only one such waiver per twelve billing cycles. This would allow residential customers who ordinarily pay on time but occasionally pay late not to be charged while retaining a general incentive for customers to pay on time.

E. Residential Gas Service

Q. Does LG&E propose to bring the rate components in residential gas rates more in line with the cost of service study?

A. Yes. LG&E is proposing a daily Basic Service Charge of \$0.65 for Rates RGS and VFD, which is equivalent to a monthly Basic Service Charge of \$19.78, which is an increase from the current monthly Basic Service Charge of \$16.35. As Mr. Seelye discusses further in his testimony, the cost of service study indicates that the customer-related cost for the residential class is $24.94 per customer per month ($0.82 per day). LG&E is therefore proposing to increase the Basic Service Charge in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost. This cost is derived in Mr. Seelye's Exhibit WSS-9.

VII. OTHER GAS RATE AND TARIFF CHANGES

A. Changes to Standard Rate Schedules

Q. Please explain the changes to Volunteer Fire Department Service (Rate VFD) at Sheet No. 9.

A. To align with the wording of Rate RGS, LG&E proposes to add text to the Availability section of Rate VFD stating that LG&E is not obligated to install an additional service to allow a customer to install equipment for either electric standby generation or personal vehicle fueling. This language is similar to and consistent with language already incorporated in Rate RGS, but previously omitted from Rate VFD.

Q. Please explain the changes to Substitute Gas Sales Service (Rate SGSS) at Sheet No. 21.1.

A. LG&E proposes to revise how the Monthly Billing Demand under Rate SGSS is determined. LG&E is proposing to no longer multiply the highest daily volume during the eleven previous months by 70%. This change is consistent with LG&E's original proposal of Rate SGSS in LG&E's 2016 base-rate case and is consistent with the purpose and intent of Rate SGSS, namely to recover from customers the full cost of the facilities such customers expect LG&E to maintain in place even if they are only rarely used.

Q. Please explain the text changes to Firm Transportation Service (Rate FT) and Rider PS-FT at Sheet Nos. 30, 30.1, 30.8, 30.9, 61.1, and 61.2.

A. First, LG&E is adding a requirement that a new customer present its request for Rate FT service at least six months prior to first receiving natural gas from LG&E under any of its rate schedules. This requirement will allow LG&E to process requests for gas transportation service in a timely fashion and ensure that a new customer is placed on the correct rate from the time it first takes gas service. LG&E is adding similar text to Rider TS-2 at Sheet No. 51.

Second, LG&E is modifying the rate structure under Rate FT. In addition to the current Administrative Charge, which LG&E is not proposing to modify or eliminate, LG&E is changing Rate FT from a one-part volumetric-only rate to a three-part rate that includes a Basic Service Charge, a monthly demand charge per Mcf of billing demand, and a volumetric charge. This change will better match cost causation and cost recovery among customers served under this rate.

Third, LG&E is revising the process whereby a customer served under Rate FT moves from one pool manager to another. The change will simplify the transfer process and make it similar to the process already in place for customers under Rider TS-2. There is no change in the overall functioning of the PS-FT pools or the responsibilities of any party.

Q. Please explain the text changes to Distributed Generation Gas Service (Rate DGGS) at Sheet No. 35.

A. LG&E proposes to modify the text of Rate DGGS to clarify that customer-owned electric generating facilities with a total connected load of 2,000 or more cubic feet per hour used to generate electricity for standby generation will be served under Rate DGGS. These text changes are meant solely to clarify what Rate DGGS already stated; they are not substantive changes.

LG&E is also making a text change to Rider TS-2 at Sheet No. 51.4 to provide that customers served under Rate DGGS, who are also provided with gas transportation service through Rider TS-2, may be required to provide at least two hours' notice of changes in the hourly rates of gas consumption.

Q. Please explain the text changes to Local Gas Delivery Service (Rate LGDS) at Sheet No. 36.

A. LG&E proposes to add text to clarify that if it constructs facilities to serve a customer under Rate LGDS, the customer must pay for all costs of those facilities prior to LG&E commencing construction. This provision ensures LG&E will be compensated for the cost of the facilities prior to their construction.

Q. Please describe LG&E's proposed change to its Special Charges at Sheet No. 45.

A. LG&E proposes to reduce the returned payment charge from $10.00 to $3.00. Mr. Seelye discusses this change and sponsors the cost support for it.

Q. Please explain the proposed new Standard Rate Rider SFC (Standard Facility Contribution).

A. LG&E proposes to add a new Standard Facility Contribution Rider to provide gas main extensions for basic gas service when the costs of those extensions are in excess of what LG&E would normally be obligated to install for a customer under its tariffed Gas Main Extension Rules. Rider SFC is based on LG&E's gas Excess Facilities Rider. However, the Excess Facilities Rider "does not apply to main extension or to other facilities which are necessary to provide basic gas service." As proposed, Rider SFC allows qualifying customers to make monthly payments (including an interest charge) over a five-year contract term for gas main extension costs not covered by the Gas Main Extension Rules. The charges under Rider SFC apply only to the customer requesting service, not to any other customer or group of customers. The rider gives LG&E the right to decline service to a customer if the excess costs to install a main extension are less than $500,000, greater than $2,000,000, or where the facilities are likely to become obsolete prior to the end of the five-year contract term. The rider also allows LG&E to decline service under the rider when the total main extension costs subject to this rider are greater than $4,000,000 per calendar year. In conjunction with the changes to the Gas Main Extension Rules that LG&E is proposing, which I discuss below, this provision would allow LG&E to extend its service to more customers, but only in a way that provides a reasonable degree of assurance that LG&E will be able to recover the cost of the investment necessary to make the additional line extension. Importantly, the customers benefiting from the gas main extensions installed pursuant to this rider are the customers paying for them.

B. <u>Changes to Adjustment Clauses</u>

Q. Why does LG&E propose to discontinue the surcredits it is currently providing electric customers related to the TCJA under Adjustment Clause TCJA at Sheet No. 89?

A. As with its electric tariff, LG&E's Adjustment Clause TCJA states, "The TCJA Surcredit shall terminate when base rates are changed following an application requesting a change in base rates."[7] This provision is reasonable because the rates resulting from this proceeding will account for the effects of the Tax Cuts and Jobs Act on a going-forward basis, negating the need for the adjustment clause to ensure customers receive the benefits of the tax savings the act created.

Q. Please explain the text change LG&E proposes to make to Adjustment Clause FF (Franchise Fee) at Sheet No. 90.

A. LG&E has revised its gas Franchise Fee Adjustment Clause to mirror its electric Franchise Fee Adjustment Clause. The change is primarily in form, not substance, though it does include the same provision added to the electric-service counterpart, namely the clarification that LG&E will not calculate or collect any franchise fees, taxes, or charges pursuant to expired, lapsed, or otherwise invalid, ineffective or inapplicable ordinances, franchise agreements, or other governmental enactments.

C. Changes to Terms and Conditions

Q. Please explain the changes to the Gas Main Extension Rules at Sheet Nos. 106 and 106.1.

A. First, LG&E proposes to add a provision that would obligate it to provide to a customer requesting permanent service a line extension in excess of one hundred (100) feet to the extent that the cost of such line extension does not exceed five times the customer's estimated annual net revenue. "Net revenue" is defined as the customer's total revenue (excluding franchise fees and school taxes) less gas supply costs, i.e., the Gas Supply Cost Component of LG&E's rates. LG&E proposes to require the customer to provide a guarantee of the estimated annual net revenue of at

[7] Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 89 (effective Apr. 1, 2018).

least five years, after taking into consideration any ramping up of the customer's demand and usage. This provision would allow LG&E to extend its service to more customers, but only in a way that provides a reasonable degree of assurance that LG&E, and therefore its customers, will be able to recover the cost of the investment necessary to make the additional line extension.

Second, LG&E proposes to revise the provision that currently states LG&E will install at its own expense a pipe of suitable capacity from its gas main to the customer's property line. This revision is necessary to account for the change in LG&E's policy under which it now installs and owns gas customer service lines and risers.

Third, on Sheet No. 99, LG&E is proposing to revise the heating value of the gas it supplies from 1,000 Btu per cubic foot to 1,050 Btu per cubic foot to reflect the higher heating value of the gas received from the interstate pipelines delivering gas to LG&E.

VIII. LOW-INCOME CUSTOMER ASSISTANCE

Q. Do the Companies provide assistance to their low-income customers?

A. Yes. The Companies are aware of their low-income customers' needs through direct contact with such customers and through the Companies' relationships with a number of organizations engaged in community-assistance programs and efforts, including the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC") and the Association of Community Ministries ("ACM"). The Companies meet and communicate with these groups on a regular basis to understand low-income customers' needs, how community organizations are working to meet those needs, and how the Companies can help.

The Companies have used the experience and knowledge gained from these interactions as they have worked on their own and in conjunction with community groups to provide various forms of assistance to low-income customers over the years. For example, KU matches customer donations to the WinterCare Energy Assistance Fund, which assists low-income customers with their utility bills during winter months. In the 2017-18 heating season alone, KU's shareholders contributed over $30,000 to WinterCare. Since 2009, customer donations and matching funds from the Companies have raised over $3.3 million for WinterCare and LG&E's Winterhelp. For the 2018-2019 heating season, KU's shareholders will once again match $1.00 for every $1.00 donated by KU's residential customers to WinterCare. Moreover, KU's employees participate in Winterblitz, an annual weatherization effort performed in conjunction with CAC. Each November, hundreds of employees join volunteers and community organizations to weatherize the homes of low-income senior citizens and the disabled. KU provides the weatherization materials for Winterblitz, and in 2017, KU employees assisted in weatherizing approximately 40 homes through their participation and donations.

Similarly, LG&E matches customer donations to the Winterhelp Energy Assistance Fund, which assists low-income customers with their utility bills during winter months. In the 2017-18 heating season alone, LG&E's shareholders contributed over $60,000 to Winterhelp. As noted above, since 2009, customer donations and matching funds from the Companies have raised over $3.3 million for Winterhelp and KU's WinterCare. For the 2018-2019 heating season, LG&E's shareholders will once again match $1.00 for every $1.00 donated by LG&E's

residential customers to Winterhelp. Moreover, LG&E has been a proud partner of Project Warm since its inception in 1982. Project Warm is a non-profit organization that provides weatherization assistance for the low-income elderly and disabled. Each November, LG&E's employees work with Project Warm in the annual Project Warm Blitz, a program whereby hundreds of employees join volunteers and community organizations to weatherize the homes of low-income senior citizens and the disabled. LG&E provides the weatherization materials for Project Warm Blitz, and in 2017, LG&E employees assisted in weatherizing approximately 280 homes through their participation and donations.

In addition, KU committed in its most recent base rate case (Case No. 2016-00370) to make annual shareholder contributions of $570,000 per year beginning in 2017 through June 30, 2021.[8] The $570,000 comprises a $100,000 contribution to WinterCare and a $470,000 contribution to the Home Energy Assistance ("HEA") program.[9] KU further agreed in that case to increase its monthly residential charge for the HEA program to $0.30 and to maintain it at that level through June 30, 2021.[10]

Likewise, LG&E committed in its most recent base rate case (Case No. 2016-00371) to make annual shareholder contributions of $880,000 per year beginning in 2017 through June 30, 2021.[11] The $880,000 comprises a $700,000 contribution to ACM for its utility assistance programs and an $180,000 contribution to the HEA

[8] Case No. 2016-00370, Order at Appx. A (June 22, 2017).
[9] *Id.*
[10] *Id.*
[11] Case No. 2016-00371, Order at Appx. A (June 22, 2017).

program.[12] LG&E further agreed in that case to maintain its monthly residential charge for the HEA program of $0.25 through June 30, 2021.[13]

Q. In addition to the Companies' significant shareholder contributions and the support the HEA charge provides to low-income customers, the Companies implemented any policy or tariff measures to assist fixed- and low-income customers?

A. Yes. The Companies provide all customers at least 22 calendar days to pay their bills after the issuance date, but go even further to assist fixed- and low-income customers. First, the Companies' FLEX Program allows residential customers with limited incomes to pay their bill 28 days from issuance. This helps prevent the fixed- and low-income customers from incurring late payment charges, increases the time in which such customers may seek financial aid, and helps reduce the issuance of disconnection notices to these customers. The popularity of the FLEX Program indicates it is achieving its intended aims: since the Companies implemented the program in December 2009 through August 2018, over 30,000 customers have used it.

Second, since October 1, 2010, a residential customer who has received a pledge or notice of low-income assistance from an authorized agency is not assessed or required to pay a late-payment charge for the bill for which the pledge or notice is received. Moreover, the customer will not be assessed or required to pay a late-payment charge in any of the 11 months following receipt of the pledge or notice. This waiver of the late-payment charge has provided significant benefits to low-

[12] *Id.*
[13] *Id.*

income customers. From September 2017 through August 2018, the Companies waived approximately $456,000 in late-payment charges, helping to alleviate the financial burden the Companies' fixed- and low-income customers are facing. This is in addition to the new late-payment-charge waiver the Companies are proposing in this proceeding, which should help low- and fixed-income customers, as well as all other customers.

Also, the Companies offer a DSM-EE program to assist low-income customers. Specifically, the Companies' Low-Income Weatherization Program ("WeCare") is an education and weatherization program designed to reduce the energy consumption of low-income customers, defined as customers who qualify for the federal Weatherization Assistance Program (i.e., customers with income up to 200% of the federally defined poverty level). The program provides energy audits, energy education, blower door tests, and installs weatherization and energy conservation measures. To increase the program's usefulness, it is available to low-income residents of multi-family dwellings. WeCare is the single largest DSM-EE program by a wide margin in the DSM-EE Program Plan the Companies proposed to the Commission in Case No. 2017-00441.[14]

In an effort to further increase low-income customers' awareness of these efforts and DSM-EE offerings, the Companies conduct outreach specifically focused on low-income customers. This outreach includes advertisements on the interior and exterior of city buses in Louisville providing information on how to access these

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[14] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-0041, Application (Dec. 6, 2017).

programs. In addition, the Companies have held meetings with various community agencies and low-income advocates to further inform these representatives of the programs and discuss how these advocates can assist low-income customers with their participation in the programs.

All of these efforts demonstrate the Companies' commitment to assisting their fixed- and low-income customers. Through the WeCare Program, the Companies work to weatherize the homes of low-income customers to decrease their monthly energy bills. The FLEX program extends the due date of low-income customers' bills to 28 days from bill issuance. To the extent further assistance is required, the Companies have generously increased giving to agencies that provide financial support, and they waive the late payment charges for customers receiving assistance from such agencies. In short, the Companies provide a wide array of assistance to their fixed- and low-income customers from before the time a customer uses energy until after the Companies issue a bill.

IX. CONCLUSION

Q. What are your conclusions and recommendations?

A. Based on the evidence provided above and in the Companies' applications in these proceedings, I conclude the rates, revenue allocations, and proposed changes to the Companies' tariffs, including eliminating Adjustment Clause TCJA, are reasonable and will aid the Companies in continuing to provide safe, reliable, and economical service to their customers. Therefore, I recommend the Commission approve the Companies' proposed rates, revenue allocations, changes to their tariffs, and the rest of the relief the Companies are requesting in these proceedings.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Robt M. Conroy
Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of September 2018.

Judy Schooler
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

Robert M. Conroy
Vice President, State Regulation and Rates
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Previous Positions

Director, Rates	Feb 2008 – Feb 2016
Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995
Edison Electric Institute - Rates and Regulatory Affairs Committee
Southeastern Energy Exchange - Rates and Regulation Committee

Education

Essentials of Leadership, London Business School, 2004
Masters of Business Administration
Indiana University (Southeast campus), December 1998
Center for Creative Leadership, Foundations in Leadership program, 1998.
Bachelor of Science in Electrical Engineering;
Rose Hulman Institute of Technology, May 1987

Civic Activities

Olmstead Parks Conservancy – Board of Directors – 2016 – current
Leadership Kentucky – Class of 2016
Financial Research Institute – Advisory Board Member – 2016 – current