Issue:	Legislative Investigation
Witness:	Michael L. Brosch
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Sponsoring Party:	Missouri Retailers, and Consumers Council of Missouri
File No.:	EW-2013-0425
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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Working Case to Address Legislative Concerns Regarding Proposals to Modify Ratemaking Procedures for Electric Utilities	**)))))**	**File No. EW-2013-0425**

Comments of

Michael L. Brosch

Legislative Investigation

On behalf of

Missouri Retailers Association and
Consumers Council of Missouri

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Table of Contents to the
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Comments of Michael L. Brosch

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Michael L. Brosch. My business address is PO Box 481934, Kansas City, Missouri 64148.

Q WHAT IS YOUR PRESENT OCCUPATION?

A I am a Principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to special services work for utility regulatory clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses and focused investigations related to utility operations and ratemaking issues.

Q ON WHOSE BEHALF ARE YOU COMMENTING IN THIS PROCEEDING?

A I am commenting on behalf of the Missouri Retailers Association ("Missouri Retailers") and the Consumers Council of Missouri. Utilitech, Inc. was engaged to review and address certain of the issues identified in the Commission's *Order Opening an Investigation to Address Legislative Concerns Regarding Proposals to Modify Ratemaking Procedures for Electric Utilities and Establish a Procedural Schedule* ("Order"). Steven Carver, also with Utilitech, is sponsoring comments on behalf of Missouri Retailers and Consumers Council of Missouri to address certain of the issues identified in the Order.

Q WHAT IS THE PURPOSE OF YOUR COMMENTS?

A My comments are responsive to the Commission's request in its Order for analysis and information in connection with Senate Bill 207 ("SB 207"). In particular, my comments are focused upon the absence of any demonstrated financial need for legislation in the form of SB 207, as it pertains to the Infrastructure System Replacement Surcharge ("ISRS"). I understand that House Bill 398 ("HB 398") is the companion legislation to SB 207 and that it differs in certain minor details from SB 207. All references in my Comments to SB 207 apply equally to HB 398, unless otherwise noted. I also offer information regarding the traditional regulatory treatment of utility infrastructure investment, under current Commission policies and procedures, in contrast to the proposed ISRS treatment, so as to explain why the electric utilities in Missouri should not be granted an ISRS.

My comments are being presented in a more formal question and answer format, rather than a narrative report style, in anticipation of the hearings that were originally scheduled by the Commission. Further, my comments were substantially complete at the time that the Commission cancelled the previously scheduled hearings. However, the substance and content of my comments would be and are identical, regardless of the format or presentation style. Because the MPSC and the Missouri electric utilities have extensive experience with the discussion and presentation of issues in a question and answer format, the form of my comments should be familiar and understandable.

EDUCATION AND EXPERIENCE

Q WHAT IS YOUR EDUCATIONAL BACKGROUND?

A Appendix A to these comments is a summary of my education and professional qualifications that also contains a listing of my previous testimonies in regulatory proceedings in Missouri and other states.

Q PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE IN THE FIELD OF UTILITY REGULATION.

A My professional experience began in 1978, when I was employed by the Missouri Public Service Commission as part of the accounting department audit staff. While with the Staff from 1978 to 1981, I participated in rate cases involving Kansas City Power and Light Company, Missouri Public Service Company, Southwestern Bell and several smaller Missouri utilities. Since leaving the Commission Staff, I have worked as an independent consultant and have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, New Mexico, Ohio, Oklahoma, Texas, Utah, Washington, and Wisconsin in regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. I have participated in many electric, gas and telephone utility regulatory proceedings, as listed and described in Appendix A. I also provided testimony in several recent legislative hearings convened by the Utilities Committee of the General Assembly in connection with House Bill 398 and with Senate Bill 240 and House Bill 473 dealing with gas utility regulation proposals.

EXECUTIVE SUMMARY

Q PLEASE SUMMARIZE YOUR COMMENTS.

A My comments describe how electric utility infrastructure investment is treated under traditional regulation in Missouri and in other states, in comparison to the treatment of new infrastructure investment under the ISRS proposal within SB 207. I discuss the importance of regulatory review of electric utility investments and the financial incentives for such investments that exist under traditional regulation, indicating how regulatory review procedures and financial incentives would be modified if an ISRS is implemented for Missouri's electric utilities. My comments focus upon the financial impact from new investments by electric utilities and whether SB 207 is needed to improve the financial performance of the utilities or to encourage incremental new infrastructure investments.

I conclude that only in limited circumstances is it financially necessary or reasonable as a matter of regulatory policy to adopt any extraordinary cost recovery procedures for new electric utility infrastructure investments. In support of this conclusion, I describe past instances when the Commission has modified its traditional regulatory treatment of new infrastructure projects, upon a showing of financial need by electric utilities under its jurisdiction. I conclude that ISRS should not be approved and instead the Commission should retain its existing practice of considering and adopting extraordinary rate treatments only when justified by utility-specific evidence of financial need and consumer benefits.

Q FOR WHAT REASONS DO YOU CONCLUDE THAT THE ELECTRIC ISRS MECHANISM PROVIDED FOR IN SB 207 IS INAPPROPRIATE AND SHOULD NOT BE IMPLEMENTED?

A The ISRS provision within SB 207 represents improper single-issue ratemaking that should not be implemented in the absence of compelling justification for such non-traditional regulation. In general, utility rates should be revised based upon an assessment of changes in the overall costs incurred to provide service, capturing all changes in revenues, expenses, rate base and cost of capital at a common and "matched" point in time – the test year. This is necessary because of the dynamic nature of utility expenses and investment, with some elements of cost increasing while others are decreasing between test years. The SB 207 proposal would focus upon a subset of the overall revenue requirement that is known to be growing and then establish ISRS surcharge rate increases for only these costs, ignoring the changes in other costs and revenues that are also be occurring between test years.[1]

The granting of piecemeal regulatory mechanisms for selected elements of this otherwise "matched" updating of prices and costs is an extraordinary form of regulatory relief that should be granted only when warranted by unusual circumstances. As noted in my comments that follow, the electric utilities have failed to show a need for such extraordinary ratemaking for net plant additions between rate case test years.

The ISRS proposal is also poor regulatory policy because it would remove the regulatory lag efficiency incentive that presently exists and that serves to encourage management to carefully optimize capital budgets and control actual capital expenditures. ISRS would allow fairly automatic future recovery of whatever amounts are spent by electric utilities on new qualifying capital additions. Adoption of ISRS can be expected to blunt the incentives for cost optimization arising from regulatory lag that are a desirable aspect of traditional rate regulation.

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[1] SB 207 also contains expense tracking provisions that would adjust future rates for accumulated changes in certain categories of expense, but these provisions would not account for changing sales and revenue levels or for changes in the cost of debt or equity capital.

Finally, ISRS is poor policy in creating an entirely new ratemaking and accounting regime that would require the investment of time and resources for incremental regulatory audit staff attention and review. If ISRS were granted for use by all Missouri electric utilities, a series of new rate filings and reconciliation calculations may be generated for all participating electric utilities twice each year, which would further burden the Commission and its Staff with new administrative responsibilities.

Q DO ELECTRIC UTILITIES IN MISSOURI NEED AN ISRS BECAUSE OF EXCESSIVE REGULATORY LAG THAT PREVENTS TIMELY RECOVERY OF NEW INFRASTRUCTURE INVESTMENTS?

A. No. Regulatory lag is typically defined as the delay between changes in revenues or costs and when those changes are formally recognized in revised utility rates. The regulatory policies adopted by this Commission serve to moderate any negative impacts of regulatory lag, while preserving important incentives arising from the delay in cost recovery that remains. It is unreasonable to focus upon only a single element of the revenue requirement, such as investments made in new plant between test years, to evaluate the adequacy of cost recovery opportunities. Regulation should instead focus upon all elements of the changing revenue requirement, including both increasing and declining costs as well as any growth in sales and revenues occurring between test years. Single-issue rate changes are poor public policy because they fail to properly measure and adjust rates for changes in the overall revenue requirement.

As more fully explained in my comments, the electric utility industry is a mature business that produces large internal cash flows that are available to fund much of the ongoing construction expenditures that are made each year by electric utilities to replace and expand infrastructure. These internally generated cash flows arise from recovery from electric ratepayers of depreciation on all of the utility's existing plant investment, recovery from ratepayers now of income tax expense that is deferred (i.e., will be remitted to taxing authorities in future years) and collection of substantial return allowances on existing rate base investment balances. New infrastructure investment that is funded by internally generated cash flows requires no new external capital resources and is not subject to any regulatory lag.

Q DO THE ELECTRIC UTILITIES IN MISSOURI HAVE A REASONABLE OPPORTUNITY TO RECOVER THEIR PRUDENTLY INCURRED COSTS AND EARN A FAIR RETURN ON INVESTMENT IN THE ABSENCE OF AN ELECTRIC ISRS?

A. Yes. The Commission's regulatory policies provide for balanced and timely rate adjustments, while ensuring that changes in the costs to provide utility service, including new investments in infrastructure, do not adversely impact utility financial results.

ELECTRIC INFRASTRUCTURE COST RECOVERY

Q HOW IS NEW ELECTRIC UTILITY PLANT INVESTMENT TREATED WHEN SETTING UTILITY RATES UNDER THE REGULATORY POLICIES TRADITIONALLY APPLIED IN MISSOURI?

A The actual costs incurred by electric utilities to build or buy new plant assets are recorded as electric Plant in Service ("EPIS") pursuant to the Uniform System of Accounts that is prescribed for regulated electric utilities.[2] The EPIS account accumulates the costs of new plant that is added in each year, for each vintage and

[2] The electric Uniform System of Accounts is codified at 18 CFR (101) and Electric Plant in Service is defined to include the original cost of electric plant, included in accounts 301 to 399, prescribed herein, owned and used by the utility in its electric utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. (See also account 106 for unclassified construction costs of completed plant actually in service.)

type of plant asset, so that the balance of EPIS grows with all additions of new assets, reduced only when existing plant assets are removed from service and "retired". Whenever a rate case is initiated, the balance of EPIS is included in rate base, where it is allowed to earn the authorized overall rate of return when determining the revenue requirement. Throughout the useful life of EPIS assets, they are includable in rate base where they are allowed to earn a return on investment. Additionally, the assets recorded within EPIS accounts are depreciated over the estimated useful life of each category of assets, with the resulting annual depreciation expense also included in the revenue requirement. Under these procedures, a new asset such as a utility pole, transformer, meter or generating unit component that is added to electric PIS is likely to be included in the utility's revenue requirement for decades into the future, for as long as the new asset remains in service.

Q. DOES THE RECOVERY OF DEPRECIATION EXPENSE FROM RATEPAYERS REDUCE THE BALANCE OF PLANT IN SERVICE THAT IS ALLOWED TO EARN A RETURN ON INVESTMENT IN THE RATEMAKING PROCESS?

A Yes. Depreciation expense recoveries associated with EPIS are recovered as an expense and are recorded within an Accumulated Depreciation account that represents the accumulated portion of EPIS investments that have been recovered from ratepayers. In rate cases, this Accumulated Depreciation balance is subtracted from the gross PIS balance in determining utility rate base, so that ratepayers are not required to provide a return on investment that has already been returned to the utility through depreciation expense recoveries in prior periods.

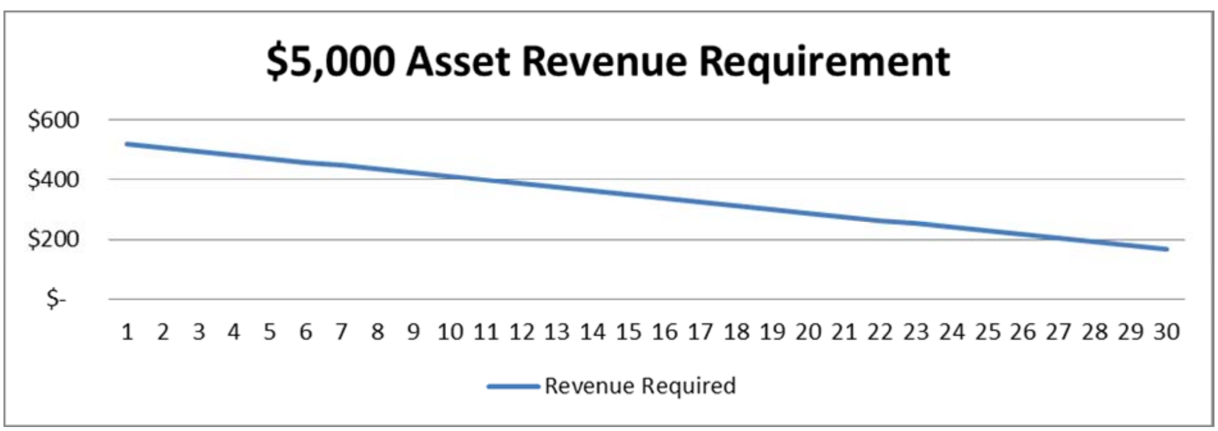
Q DO INCOME TAX REGULATIONS ALSO PROVIDE FINANCIAL SUPPORT FOR NEW ELECTRIC UTILITY INFRASTRUCTURE INVESTMENTS?

A Yes. Utility investments in new EPIS can often now be deducted immediately for income tax purposes as "repairs" expense, under the applicable provisions of

Revenue Procedures 2011-43.[3] For specific assets that are not currently deductible as repairs, new EPIS investments are afforded 50 percent bonus depreciation under current Federal income tax regulations and have historically been depreciated over other accelerated tax depreciation methods. The impact of these preferential income tax deductions for new investments is to reduce the net, after-tax cost incurred by the electric utility to make such investments. Accumulated deferred income taxes that result from such tax preferences are recorded on the utility's balance sheet and are used to reduce rate base within formal rate cases so as to recognize this source of zero cost capital in the form of deferral of income tax payments.

Q IS IT POSSIBLE TO SIMULATE THE NORMAL PATTERN OF RATE RECOVERY THAT IS ASSOCIATED WITH A TYPICAL, LONG-LIVED NEW ADDITION TO ELECTRIC UTILITY INFRASTRUCTURE?

A Yes. If we assume a simplified example of a single new utility pole with an installed cost of $5,000, a Commission-allowed pretax return of 12 percent, current income tax deduction as a "repairs" expense, and a useful life of 30 years, the pattern of annual revenue requirements associated with this new asset would appear as follows:



[3] In Rev. Proc. 2011-43, the IRS provided unit of property definitions and a safe harbor method of accounting (the Method) that taxpayers can use to determine if these expenditures must be capitalized under section 263(a) or are deductible as repairs under section 162.

The revenue requirement in year one for this new asset is only $520, or about 10 percent of the total installed cost. However, over the entire life of the asset, the total revenue requirement for return on and depreciation recovery of this asset would total more than $10,000. A large electric utility is continuously adding and retiring many discrete EPIS assets like this example utility pole, repeating this pattern of up-front investment with decades-long earnings and depreciation recovery in subsequent periods. Detailed calculations supportive of this graph are presented in Schedule MLB-1 attached to these comments.

Q ARE UTILITY RATES INCREASED AUTOMATICALLY TO ENSURE THAT EACH NEW UTILITY ASSET IS ALLOWED TO IMMEDIATELY RECOVER A RETURN AND DEPRECIATION ON NEWLY ADDED ASSETS?

A No. It is not necessary and would be improper to continuously adjust utility rates for new plant additions, because such rate adjustments would fail to comprehensively update the overall revenue requirement for other changes in revenues, expenses, taxes and the cost of capital. Rate adjustments for single elements of the revenue requirement represent poor public policy because such piecemeal rate adjustments tend to ignore offsetting cost reductions and/or revenue growth that is available to help pay for new plant investment. New EPIS utility assets are added continuously by electric utilities for many reasons. New plant can be installed to replace and retire existing electric plant assets, to replace failing or unsafe equipment, to automate business processes with computer hardware and software, to relocate facilities, to comply with environmental regulations or to expand and extend facilities to serve new customers. However, this continuum of routinely installed new asset additions and retirements need not be tracked or immediately included in rate increases because all of the other elements of the revenue requirement are also changing between utility rate cases.

Q HOW WOULD IMPLEMENTATION OF AN ELECTRIC ISRS CHANGE THE NORMAL RATEMAKING PROCEDURES THAT ARE APPLIED TO NEW INFRASTRUCTURE INVESTMENTS?

A The proposed new electric utility ISRS would allow electric rates to be increased twice annually to quickly provide a return on and depreciation of net investments in EPIS that are made by Missouri electric utilities between rate cases, within specified limitations requiring periodic rate cases every three years and limiting the dollar amounts recoverable on a piecemeal basis through ISRS rate increases.[4] In addition, until an ISRS rate surcharge is implemented, the return and depreciation on qualifying new EPIS assets would be deferred for future recovery from customers.

Q SHOULD UTILITY RATES BE FREQUENTLY ADJUSTED FOR NET ADDITIONS TO PLANT INFRASTRUCTURE IN ISOLATION, AS WOULD OCCUR UNDER ISRS?

A No. Single issue or “piecemeal” rate adjustments are inherently unreasonable because all elements of the utility’s revenue requirement tend to change between test years. It is unfair to ratepayers to charge them for known increases to only part of the revenue requirement while ignoring all of the other cost and revenue changes. For example, at the present time, utilities are able to refinance maturing tranches of long term debt and can issue new long term debt at extremely low interest rates. Between rate cases, utilities are able to retain the interest cost savings from such low-cost refinancing for the sole benefit of shareholders and these savings would be available to offset the costs of adding new EPIS or any other changes in costs and revenues. A rate case is designed to avoid piecemeal ratemaking by updating all test year expenses, revenues, rate base components and the cost of capital at the same point in time, so that rates are properly changed to match the *overall* cost of service.

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4 SB 207, at RSMO 393.1205.

Q IN THE ABSENCE OF AN ELECTRIC ISRS, WOULD MISSOURI'S ELECTRIC UTILITIES BE DENIED RECOVERY OF THEIR COSTS WHEN NEW UTILITY INFRASTRUCTURE INVESTMENTS ARE MADE BETWEEN RATE CASES?

A No. As indicated in the example above, utility infrastructure costs are eligible for recovery over the entire useful life of each new asset. For the utility pole example, where total revenue recoveries sum to more than three times the original after-tax cost of the asset over the useful life of the asset, cost recovery is assured in many future rate cases when the depreciated net cost of the asset is continuously included in rate base and recovered through depreciation accruals.

To the extent assets are added between rate cases, there could be some delay in initiating formal cost recovery, but this delay or "regulatory lag" only affects the months prior to completion of a next rate case and may be offset by other cost savings or revenue growth being experienced by the utility. For example, if we assume formal recovery of the return and depreciation on our example utility pole is delayed by two years of regulatory lag, the total recoveries on the new asset would still total more than $9,200 which substantially exceeds the nominal invested capital of $5,000 (or $3,115 after tax deferrals).[5] If any offsetting cost savings or revenue growth are experienced in other parts of the utility's business during this waiting period, or when total added infrastructure investment does not exceed the overall growth in accumulated depreciation and deferred income that occurs between test years, there may be no earnings reduction associated with infrastructure investment occurring between test years.

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[5] See Schedule MLB-1. The $5,000 of assumed initial investment, if currently tax deductible as a "repairs" expense, would require only $3,115 of actual new capital at an assumed 39% Federal and State income tax rate.

ISRS ACCELERATION OF COST RECOVERY

Q IS THE ELECTRIC UTILITY ISRS MECHANISM WITHIN SB 207 DESIGNED TO ELIMINATE THE REGULATORY LAG ASSOCIATED WITH THE COMMENCEMENT OF RATE RECOVERYOF NEW EPIS INVESTMENTS?

A Yes. The apparent purpose for adoption of an electric utility ISRS mechanism is the elimination of regulatory lag in the commencement of rate recovery for new qualifying infrastructure investments, so as to encourage utilities to make larger investments in their EPIS in Missouri.

Q WHAT IS REGULATORY LAG?

A In broadest terms, regulatory lag refers to the time it takes for information about changes in utility revenue requirements to be filed in rate case evidence and then reflected within new approved revenue and rate levels. In Missouri and the many other states that employ historical test year ratemaking procedures, regulatory lag occurs from the cut-off date of revenue requirement true-up adjustments until the date new rates become effective. Notably, regulatory lag is relevant to only those changes in revenues, expenses, cost of capital and rate base that are <u>not</u> subject to continuous ratemaking through fuel adjustment and other rate adjustment clauses or through accounting authority orders that serve to synchronize cost and revenue changes.

Q IS REGULATORY LAG A COMPLETELY UNDESIRABLE CHARACTERISTIC OF UTILITY REGULATION?

A No. An important element of traditional test period regulation is the incentive created for management to control and reduce costs, so as to maximize the opportunity to actually earn at or above the authorized return level between rate case test periods. Traditional test year regulation is not continuous regulation, because prices established in a rate case are normally fixed for a period of years, causing any changes in actual costs or sales levels to be borne by utility shareholders or ratepayers before such changes can be translated into revised prices after a "next" rate case.[6] This passage of time between rate cases, commonly referred to as "regulatory lag," serves to replace some of the efficiency incentive that is lost when prices are based upon costs to serve.

Q HAS THE MISSOURI COMMISSION PREVIOUSLY ALLOWED PIECEMEAL RATE ADJUSTMENT MECHANISMS FOR DISCRETELY LARGE NEW PLANT INVESTMENTS, BETWEEN RATE CASES, SO AS TO MITIGATE REGULATORY LAG?

A Yes. In instances of demonstrated financial need, the Commission has approved extraordinary ratemaking treatment for specific large construction programs. For example, the Sioux scrubber investment made by Ameren Missouri in the recent past was afforded continued construction accounting treatment, with deferral of depreciation expenses and a return on investment from completion of construction until the asset was included in newly approved rates.[7] Similarly, the Commission approved a multi-year "Rate Plan" for Kansas City Power and Light Company ("KCPL") that provided incremental revenues to support that utility's credit ratings during a period of large infrastructure investment.[8] In the more distant past, the Commission approved extraordinary ratemaking treatment to address the revenue requirements arising from construction of the Callaway and Wolf Creek nuclear

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6 Cost changes that are subject to rate adjustment tariffs, such as a Fuel Adjustment Clause, experience little or no regulatory lag because prudently incurred clause-includable costs can be fully recovered from ratepayers with no loss of earnings when such costs increase.

7 Sioux scrubber deferred costs were allowed rate recovery in Case No. ER-2011-0028 pursuant to the Commission's Order dated July 13, 2011.

8 The KCPL Rate Plan was approved in Case No. EO-2005-0329.

generating units in the 1980's.[9] In each of these instances, the special rate recovery mechanisms approved by the Commission were tailored to the specific facts and financial circumstances of the utility and were responsive to demonstrated needs for such extraordinary rate treatment.[10]

Q IS THE SB 207 ISRS MECHANISM COMPARABLE TO THE STEPS THAT HAVE BEEN TAKEN PREVIOUSLY BY THE COMMISSION TO ADDRESS COST RECOVERY FOR NEW INFRASTRUCTURE?

A No. The proposed new electric ISRS mechanism is different from the targeted steps previously taken by the Commission because the ISRS provides for piecemeal rate increases indiscriminately for ***all*** qualifying large and small electric utility infrastructure investments made between rate cases. This is a vastly broader approach that is not responsive to any identified deficiency in existing ratemaking polices, does not satisfy the criteria listed above, and is not tied to any regulatory verification of financial need. An electric ISRS can only produce higher rates for consumers than would exist under traditional regulation. An electric ISRS for routine plant additions is much broader than the special ratemaking approved by the Commission for Sioux Scrubber, KCPL Rate Plan and nuclear plant regulatory mechanisms were reviewed and approved by the Commission to meet specific demonstrated financial needs arising from discrete large electric utility infrastructure investments.

Q HAS THE COMMISSION PREVIOUSLY CONSIDERED AND RULED UPON THE NEED FOR EXTRAORDINARY RATE RECOVERY OF ROUTINE PLANT IN SERVICE ADDITIONS BETWEEN TEST YEARS?

[9] Nuclear plant cost recovery plans in the mid 1980's were addressed by the Commission in Case Nos. ER-84-168 and EO-85-17 for Union Electric Company and Case Nos. ER-85-128 and EO-85-185 for KCPL.

[10] Neither the Consumers Council of Missouri nor the Missouri Retailers Association make any representations regarding whether any of these special rate recovery mechanisms ultimately benefited consumers, despite the fact that the Missouri Commission adopted such mechanisms.

A Yes. In its most recent rate case, Ameren Missouri proposed an extraordinary cost recovery mechanism for its additions to EPIS between rate cases. Ameren Missouri's evidence in support of its so-called Plant in Service Accounting ("PISA") proposal asserted that a financial need existed for such a mechanism. However, after considering the evidence of financial need and other rationale for the PISA proposal, the Commission rejected Ameren Missouri's proposal. In the Report and Order in Case No. ER-2012-0166, the Commission stated:

> 8. Although PISA would have an initial impact of around $6.2 million per year in the next rate case, those costs would not end after one year. The additional revenue Ameren Missouri would recover through PISA would continue to accumulate throughout the 30-40 year life of the assets as they depreciate. Over forty years, that $6.2 million per year would total more than $240 million. Of course, the PISA would not necessarily end after a single rate case. If the Commission renewed PISA for additional years, additional recoveries would tend to pancake on top of each other and the numbers could quickly become very large.
>
> 9. Second, because PISA is a new concept that has never been tested, there are no clear standards for what would be treated as a non-revenue producing asset that should be excluded from the PISA. Instead, the Commission's Staff would have to sort through all the company's data to determine whether the company has properly classified those assets. The burden on Staff to review company information in rate cases is already substantial.
>
> 10. Third, PISA would violate the test-year principle in that it would routinely draw non-test year expenses into the test year for the next rate case. The test year principle is important because it is designed to match revenues and expenses at a given time to try to determine an appropriate revenue requirement for the company. By drawing in certain out-of-test-year expenses to be matched against test year revenues, while not examining all factors that might demonstrate a corresponding increase in revenue or decrease in expenses, PISA would unfairly increase the company's revenue requirement at the expense of ratepayers.
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> 11. The Commission does on occasion authorize accounting authority orders and tracking mechanisms that allow a utility to defer certain extraordinary costs for possible recovery in a future rate case. Several such mechanisms are authorized in this case. In addition, the Commission has authorized the use of construction accounting to help utilities deal with the financial burden of large construction projects. However, those mechanisms are premised on the existence of some extraordinary circumstance. Ameren Missouri concedes the expenses it would recover through PISA are not extraordinary, are not volatile or unpredictable, and are not outside the company's control.
>
> 12. Fourth, Ameren Missouri contends PISA is needed to provide the company with a greater incentive to invest limited capital in needed

infrastructure repairs and replacement. However, while Ameren Missouri's witness testified that there are some additional discretionary capital projects the company might like to undertake if it were allowed PISA, it did not demonstrate that there is any great un-met need for additional capital investment to ensure delivery of safe and adequate service. Indeed, there is reason to be concerned that PISA would encourage Ameren Missouri to undertake capital projects that, while helpful, are not necessary to provide safe and adequate service, thereby unnecessarily driving up rates.

13. Finally, PISA seems to be a solution in search of a problem. Ameren Missouri has had difficulty earning its allowed ROE in the past several years. The company likes to blame that failure on systemic problems in Missouri's regulatory scheme that lead to excessive regulatory lag. However, many businesses and individuals have been unable to earn as much as they might like in the economic conditions prevailing in recent years.

14. Furthermore, utility ratemaking is forward looking, concerned with current and anticipated financial conditions. What the company has earned in the past does not necessarily tell us what it will be able to earn in this future. In the past several rate cases, the Commission has implemented several trackers and other regulatory measures that should enhance Ameren Missouri's ability to earn its allowed rate of return. Those previous measures should be allowed an opportunity to work before further measures are undertaken.

15. Indeed, a surveillance report that Ameren Missouri supplied to Staff showed that for the 12 months ended June 30, 2012, within the true-up period for this case, Ameren Missouri's actual earned return on equity was 10.53 percent, which is above the 10.2 percent return on equity allowed in its last rate case. Ameren Missouri attempted to dismiss that 10.53 percent return as being attributable to warmer than normal weather and to other anomalies, but there it is. Under the circumstances, it is not clear that there is a systemic problem that needs to be solved with PISA.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

After considering Ameren Missouri's PISA proposal, the Commission finds that PISA would be bad public policy and should not be authorized. *Report and Order Issued December 12, 2012 at 33-36 footnotes omitted.*

Q DOES THE ISRS PROVISION WITHIN SB 207 SUFFER FROM ALL OF THE SAME PROBLEMS THAT CAUSED THE COMMISSION TO RECENTLY REJECT AMEREN MISSOURI'S PISA PROPOSAL?

A Yes.

Q WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE ELECTRIC UTILITY ISRS PROVISION WITHIN SB 207?

A For all the reasons stated in my comments and in the Commission's recent Report and Order rejecting Ameren Missouri's PISA proposal, SB 207 should not be adopted.

INCENTIVES FOR INFRASTRUCTURE INVESTMENT

Q DOES THE ELECRIC UTILITY INDUSTRY IN MISSOURI FACE ADEQUATE INCENTIVES TO INVEST NEW CAPITAL INTO THE BUSINESS UNDER THE PRESENT FORM OF TRADITIONAL, RATE CASE REGULATION?

A Yes. One form of incentive that stimulates new investment in utility plant is the responsibility the utility has to provide safe and reliable service to its customers. Electric utilities are granted an exclusive right to provide regulated services without competition from other electric utilities. In return, the utilities are expected to provide safe and reliable services on a non-discriminatory basis to customers within the service territory. Any significant or sustained service failures reflect negatively upon the utility and may cause negative public relations or regulatory results. It is essential that electric utilities monitor the condition and performance of plant assets to pro-actively repair or replace facilities when necessary to preserve service quality.

A second important form of incentive for new electric utility investments in infrastructure is the allowed return on investment and the assured recovery of depreciation expenses for all prudently incurred new investments. Utilities do not face any of the risks faced by competitive businesses, where changing market conditions or poor business planning can cause large new capital investments to be unprofitable. An electric utility in Missouri can expect to earn a relatively stable and compensatory return on all prudently incurred new infrastructure investments throughout the entire useful life of the new EPIS asset.

A third form of incentive for new electric infrastructure investment is the opportunity to use new information technologies to automate distribution systems and back office administrative functions. Investments made in new automation software and hardware can produce incremental operational efficiencies that can be retained for shareholders between rate cases, to help "pay for" some of the new investment.

Q EARLIER IN YOUR COMMENTS, YOU REFERRED TO REGULATORY LAG ASSOCIATED WITH THE RECOVERY OF RETURN AND DEPRECIATION ON NEWLY ADDED EPIS ASSETS BETWEEN TEST YEARS. DOES REGULATORY LAG SERVE TO DISCOURAGE NEW ELECTRIC UTILITY INFRASTRUCTURE INVESTMENTS?

A Regulatory lag injects some cost control discipline into the management of utility infrastructure construction budgets, which may reduce or delay investments that are more discretionary in the short term. This is a desirable attribute of regulation that encourages utility management to carefully prioritize projects and allocate scarce capital investment where it is most efficient. Without some regulatory lag associated with new capital investments, along with the risk of potential prudence review and disallowance, the cost-plus nature of utility rate regulation would tend to encourage maximizing new investments without regard to prudence or economic efficiency. Regulatory lag serves as a desirable incentive for utility management to optimize its infrastructure investments to minimize overall costs borne by ratepayers while not allowing service quality to deteriorate.

Q HAS THE COMMISSION APPROVED REGULATORY DEFERRALS OR OTHER FORMS OF EXTRAORDINARY RATE TREATMENT FOR LARGE

INFRASTRUCTURE PROJECTS WHERE REGULATORY LAG CREATED A SIGNIFICANT FINANCIAL BURDEN?

A Yes. As discussed in my previous comments and in the Commission's Report and Order in Case No. 2012-0166, the Commission has authorized the use of construction accounting to help utilities deal with the financial burden of large construction projects. However, those mechanisms are premised on the existence of some extraordinary circumstance. The routine annual infrastructure investments made by Missouri electric utilities in the normal course of business do not represent any financial burden and no showing has been made that any extraordinary rate treatment in the form of ISRS is needed for such investments.

Q WOULD THE ELECTRIC UTILITY ISRS PROVISION WITHIN SB 207 ELIMINATE AN IMPORTANT EFFICIENCY INCENTIVE THAT WOULD OTHERWISE EXIST WITH RESPECT TO NEW INFRASTRUCTURE INVESTMENTS?

A Yes. There would no longer be any financial incentive for utility management to conservatively manage ongoing infrastructure investments because of regulatory lag. Every dollar of new investment eligible for ISRS would be treated as immediately recoverable from ratepayers because the ISRS Costs defined in SB 207 also includes a provision for deferral of depreciation and return on ISRS investments as a regulatory asset or liability "…between the time the eligible infrastructure system replacements and additions were placed in service and the effective date of any ISRS rate schedule reflecting the deferred depreciation and return."[11]

Q IS IT LIKELY THAT ANY EXCESSIVE OR IMPRUDENT NEW INVESTMENTS THAT MAY RESULT FROM AN ELECTRIC ISRS WOULD BE DETECTED AND BECOME THE SUBJECT OF A PRUDENCE DISALLOWANCE?

[11] SB 207 at RSMO 393.1200(7)(b).

A Probably not. Regulatory prudence investigations tend to be extremely complicated and contentious, requiring detailed discovery of relevant factual information and independent analysis of utility management judgments by experts who are skilled in all phases of construction planning and management and who also possess the forensic engineering and regulatory accounting expertise required to develop and present evidence in support of recommended disallowances. These efforts are costly and time consuming and are likely to be focused upon only discretely large projects that happen to attract attention because of known problems, delays and/or cost over-runs relative to budget. The risk of prudence disallowance is no substitute for the efficiency incentives created by the modest regulatory lag that currently applies to new infrastructure investments in Missouri.

Q IF APPROVAL OF SB 207 HAS THE EFFECT OF ACCELERATING THE PACE OF ELECTRIC UTILITY INVESTMENTS THAT WOULD EVENTUALLY BE NEEDED, IS IT LIKELY THAT RATEPAYERS WOULD BE BETTER OFF FINANCIALLY?

A No. The Commission should assume, in the absence of any evidence to the contrary, that Missouri electric utilities are presently operating their businesses and making infrastructure investments in a manner that is responsive to business requirements and is economically optimal. Where new investments are justified economically through improvements in reliability and/or reduced operations or maintenance expenses, they are likely being made. Where investments are required to comply with environmental regulations or to maintain public and employee safety, they are likely to be made. Where investments are mandated by governmental authorities to relocate electric facilities, they are likely to be made. Where new investments are required to extend or expand facilities to serve new customers or increased demands of existing customers, they are likely to be made. Accelerating any of these types of currently optimized electric utility investments is likely to create only increased costs to ratepayers, by adding EPIS investments into rate base sooner or by prematurely retiring and replacing existing assets before they would otherwise be removed from service.

Q WOULD IT BENEFIT RATEPAYERS IF MISSOURI ELECTRIC UTILITIES TOOK ADVANTAGE OF CURRENTLY LOW INTEREST RATES TO ISSUE NEW DEBT FINANCING, SO AS TO FUND ACCELERATION OF NEW INFRASTRUCTURE INVESTMENT?

A No. Even if we assume, for the sake of argument, that the timing of certain elements of new electric utility infrastructure investment are entirely discretionary and could be accelerated with some earlier potential benefit to customers, the incurrence of such costs earlier than necessary would create a burden upon ratepayers. This is true because Missouri ratepayers also experience a time value of money that causes higher electric bills imposed sooner to be more burdensome than higher electric bills imposed later. Residential consumers are a diverse group in terms of their marginal interest rate, with many postured as net investors paying consumer interest as high as 18 to 20 percent on credit cards, while others as net investors earning very low returns on available consumer savings accounts and others are barely able to pay utility bills at all. Commercial and industrial customers should also be assumed to experience a marginal interest rate on their working capital that causes higher electric bills due sooner than later to represent an economic burden. I am not aware of reliable published sources of average or representative marginal costs of capital applicable to Missouri electric ratepayers, but am certain that an extra dollar paid now for electric service is more valuable than an extra dollar paid later.

It should also be noted that the cost of capital prescribed within SB 207 as the appropriate pretax revenue for a return on ISRS investments is limited to, "The electrical corporation's actual regulatory capital structure as determined during the most recent general rate proceeding of the electrical corporation" and "The actual cost rates for the electrical corporation's debt and preferred stock as determined during the most recent general rate proceeding of the electric corporation." These terms would ensure that the revenue requirement savings arising from any increase in the debt ratio or any reduction in the weighted cost of debt from newly issued debt to fund accelerated infrastructure investment would be retained by the utilities for the sole benefit of their shareholders between rate cases.

ABILITY TO INVEST

Q ONE OF THE AREAS OF ANALYSIS SPECIFIED IN THE COMMISSION'S ORDER OPENING THIS INVESTIGATION IS THE ELECTRIC UTILITIES' FINANCIAL NEED FOR LEGISLATION. HAVE YOU INVESTIGATED THE CURRENT ABILITY OF MISSOURI'S ELECTRIC UTILITIES TO FUND NEEDED INFRASTRUCTURE INVESTMENTS?

A I have reviewed publicly available financial data for Missouri's electric utilities regarding cash flows and liquidity. In the absence of any opportunity for focused discovery on this topic, I examined the publicly available financial disclosures in SEC Form 10-K filings made by Ameren Missouri, Great Plains Energy and Empire District Electric Company for the most recently available annual period. Excerpts of these documents are contained within Schedule MLB-2 attached to my Comments.

Q HOW DOES AMEREN MISSOURI DESCRIBE ITS ACCESS TO CAPITAL?

A Referring to Schedule MLB-2 at 10-K page 114, Ameren Missouri had direct access to $800 million of liquidity through the 2012 Missouri Credit Agreement and an option to seek additional commitments from existing or new lenders of up to $1.2 billion, in addition to its intercompany borrowing capabilities, to supplement its substantial internally generated cash flows.

Q IS AMEREN MISSOURI ABLE TO FUND MOST OF ITS ANNUAL INFRASTRUCTURE FROM ITS INTERNALLY GENERATED CASH FLOWS?

A Yes. Like most large electric utilities, Ameren Missouri recovers from its ratepayers substantial annual cash flows associated with its net income, recoveries of depreciation expense and collection of deferred income taxes that need not be paid to the taxing authorities currently. According to the Ameren Corporation SEC Form 10-K for Ameren Missouri (Union Electric Company), the regulated utility in Missouri has been able to fund much more than 100 percent of its annual construction expenditures from internal cash flows rather than new external financing.

Ameren Missouri (Union Electric) Cash Flow Statement ($ in millions):			
Summary of Sources & Uses of Cash	**2012**	**2011**	**2010**
Net Income	$ 419	$ 290	$ 369
Depreciation/Amort Recovery	407	377	355
Income Tax Deferrals	287	155	292
Other Internal Source of Cash	-109	234	-47
TOTAL INTERNALLY GENERATED	$ 1,004	$ 1,056	$ 969
Construction Expenditures	-686	-612	-692
Dividends Paid	-403	-406	-240
% OF CONSTRUCTION INTERNALLY FUNDED	146%	173%	140%
Source: SEC 10-K FYE 12/31/12, page 93.			

There is clearly no need for an electric ISRS for Ameren Missouri based upon any perceived need for improved cash flow, as illustrated by these results.

Q HOW DOES GREAT PLAINS ENERGY DESCRIBE ITS ACCESS TO CAPITAL?

A Referring to Schedule MLB-2 at 10-K page 37, Great Plains Energy, the parent company of KCPL and the Greater Missouri Operations ("GMO") had direct access to $678 million of unused bank lines of credit as of December 31, 2012, in addition to its intercompany borrowing capabilities, to supplement its substantial internally generated cash flows.

Q IS GREAT PLAINS ENERGY ABLE TO FUND MOST OF ITS ANNUAL INFRASTRUCTURE FROM ITS INTERNALLY GENERATED CASH FLOWS?

A Yes. While the publicly available financial statements are consolidated and therefore include KCPL operations in Missouri and Kansas, as well as GMO operations in Missouri, they clearly show strong internally generated cash flow that are improving and available to fund nearly all of the Company's recent infrastructure investments.

Great Plains Energy (consolidated) Cash Flow:			
Summary of Sources & Uses of Cash	**2012**	**2011**	**2010**
Net Income	$ 199	$ 174	$ 212
Depreciation/Amort Recovery	333	307	352
Income Tax Deferrals	121	111	124
Other Internal Source of Cash	11	-149	-136
TOTAL INTERNALLY GENERATED	$ 664	$ 443	$ 552
Construction Expenditures	-615	-462	-646
Dividends Paid	-125	-115	-114
% OF CONSTRUCTION INTERNALLY FUNDED	108%	96%	85%
Source: Annual Report to Shareholders, p.52.			

I have included within Schedule MLB-2 copies of selected pages from the Great Plains Energy

Q HOW DOES EMPIRE DISTRICT ELECTRIC COMPANY DESCRIBE ITS ACCESS TO CAPITAL?

A Referring to Schedule MLB-2 at 10-K page 78, Empire had direct access to a $150 million Unsecured Credit Agreement, of which $24 million was used to back up outstanding commercial paper as of December 31, 2012, in addition to its substantial internally generated cash flows.

Q WAS EMPIRE DISTRICT ELECTRIC ALSO ABLE TO FUND MOST OF ITS ANNUAL INFRASTRUCTURE SPENDING FROM ITS INTERNALLY GENERATED CASH FLOWS IN RECENT YEARS?

A Yes. Empire's Consolidated Statements of Cash Flows within its December 31, 2012 SEC Form 10-K report illustrate quite strong internal cash flow generation that has provided internal funding for the Company's annual construction expenditures in each of the past three calendar years.

Empire District Electric Company Cash Flow (all states):			
<u>Summary of Sources & Uses of Cash</u>	**2012**	**2011**	**2010**
Net Income	$ 56	$ 55	$ 47
Depreciation/Amort Recovery	71	80	71
Income Tax Deferrals	32	45	27
Other Internal Source of Cash	0	-46	-9
TOTAL INTERNALLY GENERATED	$ 159	$ 134	$ 136
Construction Expenditures	-135	-99	-106
Dividends Paid	-42	-27	-51
% OF CONSTRUCTION INTERNALLY FUNDED	118%	135%	128%
Source: 12/31/12 SEC Form 10-K, p.49			

Q DOES THE PUBLICLY AVAILABLE FINANCIAL INFORMATION FOR MISSOURI'S ELECTRIC UTILITIES REVEAL ANY FINANCIAL NEED FOR THE ACCELERATED COST RECOVERIES THAT WOULD OCCUR PURSUANT TO THE ELECTRIC ISRS THAT IS PROVIDED FOR IN SB 207?

A No. Missouri's electric utilities are large and mature businesses with stable net income and strong internal cash flows that provide funding for the majority, and in some instances all of the infrastructure construction costs that were incurred in recent years. These utilities maintain strong investment grade credit ratings and do not regulatory sweeteners in the form of SB 207 to improve their financial results or to enable the Companies to meet their service obligations to customers.

Q DOES THIS CONCLUDE YOUR COMMENTS?

A Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Working Case to Address Legislative Concerns Regarding Proposals to Modify Ratemaking Procedures for Electric Utilities	)	**File No. EW-2013-0425**

STATE OF MISSOURI)
) **SS**
COUNTY OF JACKSON)

Affidavit of Michael L. Brosch

Michael L. Brosch, being first duly sworn, on his oath states:

1. My name is Michael L. Brosch. I am President of Utilitech, Inc., having its principal place of business at PO Box 481934, Kansas City, Missouri 64148. We have been retained by the Missouri Retailers Association and Consumers Council of Missouri in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my comments and schedules which were prepared in written form for Missouri Public Service Commission Case No. EW-2013-0425.

3. I hereby swear and affirm that the comments and schedules are true and correct and that they show the matters and things that they purport to show.

Michael L. Brosch

Michael L. Brosch

Subscribed and sworn to before me this first day of April 2013.

MARY JO BROSCH
Notary Public, State of Kansas
My Appointment Expires
7-19-2014

Mary Jo Brosch

Notary Public

Michael L. Brosch
Summary of Qualifications

Michael L. Brosch
Utilitech, Inc. – President
Bachelor of Business Administration (Accounting)
University of Missouri-Kansas City (1978)
Certified Public Accountant Examination (1979)

GENERAL

Mr. Brosch serves as the director of regulatory projects and President of the firm and is responsible for the planning, supervision and conduct of firm engagements. His academic background is in business administration and accounting and he holds CPA certificates in Kansas and Missouri. Expertise is concentrated within regulatory policy, financial and accounting areas with an emphasis in revenue requirements, business reorganization and alternative regulation.

EXPERIENCE

Mr. Brosch has supervised and conducted the preparation of rate case exhibits and testimony in support of revenue requirements and regulatory policy issues involving more than 100 electric, gas, telephone, water, and sewer proceeding across the United States. Responsible for virtually all facets of revenue requirement determination, cost of service allocations and tariff implementation in addition to involvement in numerous utility merger, alternative regulation and other special project investigations.

Industry restructuring analysis for gas utility rate unbundling, electric deregulation, competitive bidding and strategic planning, with testimony on regulatory processes, asset identification and classification, revenue requirement and unbundled rate designs and class cost of service studies.

Analyzed and presented testimony regarding income tax related issues within ratemaking proceedings involving interpretation and application of relevant IRS code provisions and regulatory restrictions.

Conducted extensive review of the economic impact upon regulated utility companies of various transactions involving affiliated companies. Reviewed the parent-subsidiary relationships of integrated electric and telephone utility holding companies to determine appropriate treatment of consolidated tax benefits and capital costs. Sponsored testimony on affiliated interests in numerous consolidated energy utility rate cases and telephone company rate proceedings.

Has substantial experience in the application of lead-lag study concepts and methodologies in determination of working capital investment to be included in rate base.

Conducted alternative regulation analyses for clients in Arizona, California, Hawaii, Illinois, Texas and Oklahoma, focused upon challenges introduced by cost-based regulation, incentive effects available through alternative regulation and balancing of risks, opportunities and benefits among stakeholders. Analyses included targeted rate adjustment clauses, regulatory deferral accounting mechanisms and formula rate adjustment programs, including advisory work in the design of such plans as well as analyses and administration of alternative regulation plans after implementation.

Mr. Brosch managed the detailed regulatory review of utility mergers and acquisitions, diversification studies and holding company formation issues in energy and telecommunications transactions in multiple states. Sponsored testimony regarding merger synergies, merger accounting and tax implications, regulatory planning and price path strategies. Traditional horizontal utility mergers as well as leveraged buyouts of utility properties by private equity investors were addressed in several states.

WORK HISTORY

1985 - Present **Principal** - Utilitech, Inc. (Previously Dittmer, Brosch and Associates, Inc.)

1983 - 1985: **Project manager** - Lubow McKay Stevens and Lewis.
Responsible for supervision and conduct of utility regulatory projects on behalf of industry and regulatory agency clients.

1982 - 1983: **Regulatory consultant** - Troupe Kehoe Whiteaker and Kent.
Responsible for management of rate case activities involving analysis of utility operations and results, preparation of expert testimony and exhibits, and issue development including research and legal briefs. Also involved in numerous special projects including financial analysis and utility systems planning. Taught firm's professional education course on "utility income taxation - ratemaking and accounting considerations" in 1982.

1978 - 1982: **Senior Regulatory Accountant** - Missouri Public Service Commission.
Supervised and conducted rate case investigations of utilities subject to PSC jurisdiction in response to applications for tariff changes. Responsibilities included development of staff policy on ratemaking issues, planning and evaluating work of outside consultants, and the production of comprehensive testimony and exhibits in support of rate case positions taken.

OTHER QUALIFICATIONS

Bachelor of Business Administration - Accounting, 1978
University of Missouri - Kansas City

Member
American Institute of Certified Public Accountants
Missouri Society of Certified Public Accountants
Kansas Society of Certified Public Accountants

Attended
Iowa State Regulatory Conference 1981, 1985
Regulated Industries Symposium 1979, 1980
Michigan State Regulatory Conference 1981
United States Telephone Association Round Table 1984
NARUC/NASUCA Annual Meeting 1988, Speaker
NARUC/NASUCA Annual Meeting 2000, Speaker
NASUCA Regional Consumer Protection Meeting 2007, Speaker

Instructor
INFOCAST Ratemaking Courses
Arizona Staff Training
Hawaii Staff Training

Utility	Jurisdiction	Agency	Docket/Case Number	Represented	Year	Addressed
Green Hills Telephone Company	Missouri	PSC	TR-78-282	Staff	1978	Rate Base, Operating Income
Kansas City Power and Light Co.	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-79-59	Staff	1979	Rate Base, Operating Income
Nodaway Valley Telephone Company	Missouri	PSC	16,567	Staff	1979	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone Company	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income
Southwestern Bell Telephone Co.	Missouri	PSC	TR-79-213	Staff	1979	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-80-118 GR-80-117	Staff	1980	Rate Base, Operating Income
Southwestern Bell Telephone Co.	Missouri	PSC	TR-80-256	Staff	1980	Affiliate Transactions
United Telephone Company	Missouri	PSC	TR-80-235	Staff	1980	Affiliate Transactions, Cost Allocations
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base

United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes
Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues

UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest
Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaii Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply

Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting
ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Midwest Energy, Inc.	Kansas	KCC	02-MDWG-922-RTS	Agriculture Customers	2002	Rate Design, Cost of Capital
Qwest Communications – Dex Sale	Utah	PSC	02-049-76	Consumer Advocate	2003	Directory Publishing

Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications – Price Cap Review	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base, Fair Value, Alternative Regulation
Verizon Northwest Corp	Washington	WUTC	UT-040788	Public Counsel	2004	Directory Publishing, Rate Base, Operating Income
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counsel	2005	Operating Income, Debt Service, Working Capital, Affiliate Transactions, Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Sprint/Nextel Corporation	Washington	WUTC	UT-051291	Public Counsel	2006	Directory Publishing, Corporate Reorganization
Puget Sound Energy, Inc.	Washington	WUTC	UE-060266 and UG-060267	Public Counsel	2006	Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Community Benefits / Rate Discounts
Cascade Natural Gas Company	Washington	WUTC	UG-060259	Public Counsel	2006	Alternative Regulation
Arizona Public Service Company	Arizona	ACC	E-01345A-05-0816	Staff	2006	Cost of Service Allocations
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Capital Improvements and Discounted Rates
Hawaii Electric Light Company	Hawaii	HPUC	05-0315	Consumer Advocate	2006	Operating Income, Rate Base, Cost of Service, Rate Design
Union Electric Company d/b/a AmerenUE	Missouri	PSC	2007-0002	Attorney General	2007	Operating Income, Rate Base, Fuel Adjustment Clause
Hawaiian Electric Company	Hawaii	PUC	2006-0386	Consumer Advocate	2007	Operating Income, Cost of Service, Rate Design
Maui Electric Company	Hawaii	PUC	2006-0387	Consumer Advocate	2007	Operating Income, Cost of Service, Rate Design
Peoples Gas / North Shore Gas Company	Illinois	ICC	07-0241 07-0242	Attorney General	2007	Rate Adjustment Clauses

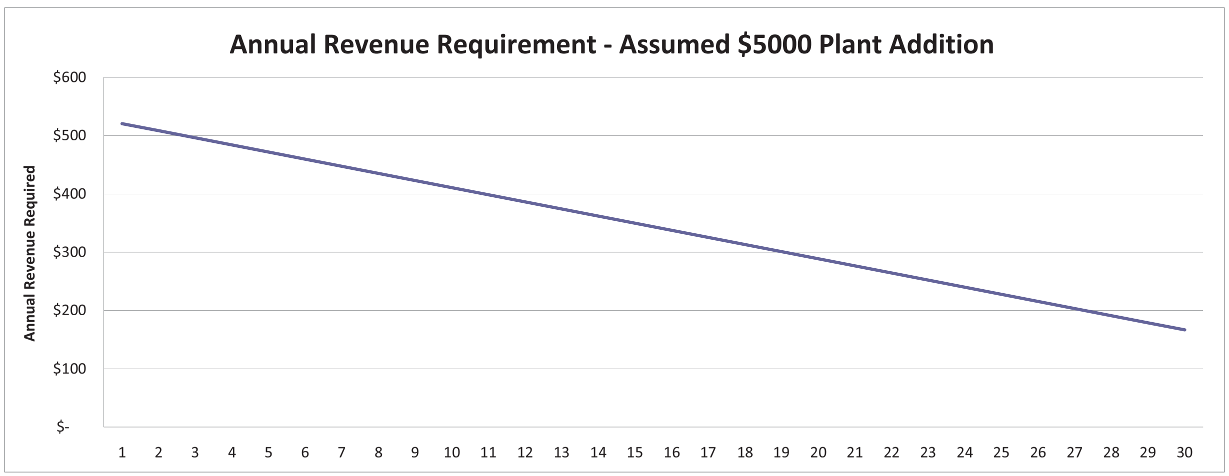
Commonwealth Edison	Illinois	ICC	07-0566	Attorney General, City	2008	Ratemaking Policy, Rate Trackers
Illinois Power Company, Illinois Public Service Co., Central Illinois Public Service Co	Illinois	ICC	07-0585 cons.	Attorney General/CUB	2008	Rate Adjustment Clauses
Southwestern Public Service Company	Texas	PUCT	35763	Municipalities	2008	Operating Income, Rate Base, Affiliate Transactions
The Gas Company	Hawaii	PUC	2008-0081	Consumer Advocate	2009	Operating Income, Rate Base, Affiliate Transactions, Cost of Service, Rate Design
Hawaiian Electric Company	Hawaii	PUC	2008-0083	Consumer Advocate	2009	Operating Income, Rate Base, Affiliate Transactions, Cost of Service, Rate Design
Commonwealth Edison	Illinois	ICC	2009-0263	Attorney General	2009	Rate Adjustment Clauses
Avista Corporation	Washington	WUTC	UG-060518	Attorney General	2009	Rate Adjustment Clauses
Kauai Island Utility Cooperative	Hawaii	PUC	2009-0050	Consumer Advocate	2009	Operating Income, Cooperative Ratemaking Policies, Cost of Service
Maui Electric Company	Hawaii	PUC	2009-0163	Consumer Advocate	2010	Operating Income, Rate Base, Cost of Service, Rate Design
Hawaii Electric Light Company	Hawaii	PUC	2009-0164	Consumer Advocate	2010	Operating Income, Rate Base, Cost of Service, Rate Design
Commonwealth Edison	Illinois	ICC	2010-0467	AG / CUB	2010	Operating Income, Rate Base
Commonwealth Edison	Illinois	ICC	2010-0527	Attorney General	2010	Alternative Regulation
Atmos Pipeline - Texas	Texas	RCT	GUD 10000	ATM Cities	2010	Operating Income, Rate Base, Cost of Service, Rate Adjustment Clause
Ameren Missouri	Missouri	PSC	2011-0028	Industrial Customers	2011	Operating Income, Rate Base
Hawaiian Electric Company	Hawaii	PUC	2010-0080	Consumer Advocate	2011	Operating Income, Rate Base, Affiliate Transactions, Cost of Service, Rate Design
Utilities, Inc.	Illinois	ICC	11-0561..0566	Attorney General	2011	Operating Income, Rate Base, Rate Design
Commonwealth Edison	Illinois	ICC	11-0721	AG / CUB	2011	Alternative Regulation
Utilities, Inc.	Illinois	ICC	11-0059 RH	AG	2012	Rate Design
Maui Electric, Ltd.	Hawaii	PUC	2011-0092	Consumer Advocate	2012	Operating Income, Rate Base, Cost of Service, Rate Design
Ameren Illinois Utilities	Illinois	ICC	12-0001	AG/AARP	2012	Alternative Regulation
Commonwealth Edison	Illinois	ICC	12-0321	AG	2012	Alternative Regulation
Ameren Illinois Utilities	Illinois	ICC	12-0293	AG	2012	Alternative Regulation
Ameren Missouri	Missouri	PSC	ER2012-0166	Industrials	2012	Income Taxes, Alternative Reg
Atmos Energy	Texas	RCT	10170	Municipals	2012	Operating Income, Rate Base
Peoples/North Shore Gas	Illinois	ICC	12-0511	AG	2012	Operating Income, Rate Base

Missouri Public Service Commission
File No. EW-2013-0425
Example of Hypothetical Rate Base Plant Investment
Revenue Requirements by Year and Cumulative

Year >>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PIS	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Depr.	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167
Accum Depr.	(167)	(333)	(500)	(667)	(833)	(1,000)	(1,167)	(1,333)	(1,500)	(1,667)	(1,833)	(2,000)	(2,167)	(2,333)	(2,500)
ADIT	(1,885)	(1,820)	(1,755)	(1,690)	(1,625)	(1,560)	(1,495)	(1,430)	(1,365)	(1,300)	(1,235)	(1,170)	(1,105)	(1,040)	(975)
Net Invest	2,948	2,847	2,745	2,643	2,542	2,440	2,338	2,237	2,135	2,033	1,932	1,830	1,728	1,627	1,525
Return @ 12%	354	342	329	317	305	293	281	268	256	244	232	220	207	195	183
Rev Required	$ 520	$ 508	$ 496	$ 484	$ 472	$ 459	$ 447	$ 435	$ 423	$ 411	$ 398	$ 386	$ 374	$ 362	$ 350

After Tax Invested $ 3,115

Year >>	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total
PIS	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	
Depr.	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	
Accum Depr.	(2,667)	(2,833)	(3,000)	(3,167)	(3,333)	(3,500)	(3,667)	(3,833)	(4,000)	(4,167)	(4,333)	(4,500)	(4,667)	(4,833)	(5,000)	
ADIT	(910)	(845)	(780)	(715)	(650)	(585)	(520)	(455)	(390)	(325)	(260)	(195)	(130)	(65)	-	
Net Invest	1,423	1,322	1,220	1,118	1,017	915	813	712	610	508	407	305	203	102	-	
Return @ 12%	171	159	146	134	122	110	98	85	73	61	49	37	24	12	-	
Rev Required	$ 337	$ 325	$ 313	$ 301	$ 289	$ 276	$ 264	$ 252	$ 240	$ 228	$ 215	$ 203	$ 191	$ 179	$ 167	**$ 10,307**
Delayed Recovery																**$ 9,278**
																90.02%



Schedule MLB-1

Schedule MLB-1
Michael Brosch
Page 1

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(X) Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 **for the fiscal year ended December 31, 2012.**

OR

( ) Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to .

Commission File Number	Exact name of registrant as specified in its charter; State of Incorporation; Address and Telephone Number	IRS Employer Identification No.
1-14756	**Ameren Corporation** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-1723446
1-2967	**Union Electric Company** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-0559760
1-3672	**Ameren Illinois Company** (Illinois Corporation) 6 Executive Drive Collinsville, Illinois 62234 (618) 343-8039	37-0211380

Securities Registered Pursuant to Section 12(b) of the Act:

The following security is registered pursuant to Section 12(b) of the Securities Exchange Act of 1934 and is listed on the New York Stock Exchange:

Registrant	Title of each class
Ameren Corporation	Common Stock, $0.01 par value per share

Securities Registered Pursuant to Section 12(g) of the Act:

Registrant	Title of each class
Union Electric Company	Preferred Stock, cumulative, no par value, stated value $100 per share
Ameren Illinois Company	Preferred Stock, cumulative, $100 par value per share Depository Shares, each representing one-fourth of a share of 6.625% Preferred Stock, cumulative, $100 par value per share

Indicate by checkmark if each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Ameren Corporation	Yes	(X)	No	( )
Union Electric Company	Yes	( )	No	(X)
Ameren Illinois Company	Yes	( )	No	(X)

Indicate by checkmark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Ameren Corporation	Yes	( )	No	(X)
Union Electric Company	Yes	( )	No	(X)
Ameren Illinois Company	Yes	( )	No	(X)

Indicate by checkmark whether the registrants: (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

UNION ELECTRIC COMPANY
STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31, 2012	2011	2010
Cash Flows From Operating Activities:			
Net income	$ 419	$ 290	$ 369
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss from regulatory disallowance	—	89	—
Gain on sale of properties	—	(3)	(5)
Net mark-to-market (gain) loss on derivatives	—	1	(1)
Depreciation and amortization	407	377	355
Amortization of nuclear fuel	83	61	54
Amortization of debt issuance costs and premium/discounts	6	6	4
Deferred income taxes and investment tax credits, net	287	155	292
Allowance for equity funds used during construction	(31)	(30)	(50)
Other	8	(6)	10
Changes in assets and liabilities:			
Receivables	27	66	(122)
Materials and supplies	(48)	(7)	7
Accounts and wages payable	(27)	13	(24)
Taxes accrued	(46)	(6)	55
Assets, other	(35)	79	(101)
Liabilities, other	14	(30)	75
Pension and other postretirement benefits	2	2	(3)
Taum Sauk insurance recoveries, net of costs	—	(1)	54
Premiums paid on long-term debt repurchases	(62)	—	—
Net cash provided by operating activities	1,004	1,056	969
Cash Flows From Investing Activities:			
Capital expenditures	(505)	(550)	(624)
Nuclear fuel expenditures	(91)	(62)	(68)
Purchases of securities – nuclear decommissioning trust fund	(403)	(220)	(271)
Sales and maturities of securities – nuclear decommissioning trust fund	384	199	256
Money pool advances, net	(24)	—	—
Tax grants received related to renewable energy properties	18	—	—
Other	8	6	7
Net cash used in investing activities	(703)	(627)	(700)
Cash Flows From Financing Activities:			
Dividends on common stock	(400)	(403)	(235)
Dividends on preferred stock	(3)	(3)	(5)
Redemptions, repurchases, and maturities:			
Long-term debt	(427)	(5)	(70)
Preferred stock	—	—	(33)
Issuances of long-term debt	482	—	—
Capital issuance costs	(7)	—	(4)
Capital contribution from parent	1	—	—
Generator advances received for construction	—	—	13
Repayments of generator advances received for construction	—	(19)	—
Net cash used in financing activities	(354)	(430)	(334)
Net change in cash and cash equivalents	(53)	(1)	(65)
Cash and cash equivalents at beginning of year	201	202	267
Cash and cash equivalents at end of year	$ 148	$ 201	$ 202
Cash Paid (Refunded) During the Year:			
Interest (net of $15, $25, and $26 capitalized, respectively)	$ 220	$ 210	$ 213
Income taxes, net	(3)	9	(106)

The accompanying notes as they relate to Ameren Missouri are an integral part of these financial statements.

Schedule MLB-2
Michael Brosch
Page 2

NOTE 3 - PROPERTY AND PLANT, NET

The following table presents property and plant, net, for each of the Ameren Companies at December 31, 2012, and 2011:

	Ameren[(a)(b)]	Ameren Missouri[(b)]	Ameren Illinois
2012			
Property and plant, at original cost:			
Electric	$ 22,055	$ 15,638	$ 4,985
Natural gas	1,854	393	1,461
	23,909	16,031	6,446
Less: Accumulated depreciation and amortization	8,823	6,614	1,495
	15,086	9,417	4,951
Construction work in progress:			
Nuclear fuel in process	317	317	—
Other	693	427	101
Property and plant, net	$ 16,096	$ 10,161	$ 5,052
2011			
Property and plant, at original cost:			
Electric	$ 24,717	$ 15,099	$ 4,684
Natural gas	1,751	385	1,368
	26,468	15,484	6,052
Less: Accumulated depreciation and amortization	9,429	6,276	1,364
	17,039	9,208	4,688
Construction work in progress:			
Nuclear fuel in process	255	255	—
Other	833	495	82
Property and plant, net	$ 18,127	$ 9,958	$ 4,770

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries as well as intercompany eliminations.

(b) Amounts in Ameren and Ameren Missouri include two electric generation CTs under two separate capital lease agreements. The gross asset value of those agreements was $228 million and $229 million at December 31, 2012, and 2011, respectively. The total accumulated depreciation associated with the two CTs was $52 million and $52 million at December 31, 2012, and 2011, respectively. In addition, Ameren Missouri has investments in debt securities, which are classified as held-to-maturity, related to the two CTs from the city of Bowling Green and Audrain County. As of December 31, 2012, and 2011, the carrying value of these debt securities was $304 million and $309 million, respectively.

See Note 17 - Impairment and Other Charges for information regarding Ameren's noncash long-lived asset impairment charges recognized in 2012.

The following table provides accrued capital expenditures at December 31, 2012, 2011, and 2010, which represent noncash investing activity excluded from the statements of cash flows:

	Ameren[(a)]	Ameren Missouri	Ameren Illinois
2012	$ 108	$ 63	$ 37
2011	107	73	18
2010	79	53	15

(a) Includes amounts for Ameren registrant and nonregistrant subsidiaries.

NOTE 4 - SHORT-TERM DEBT AND LIQUIDITY

The liquidity needs of the Ameren Companies are typically supported through the use of available cash, short-term intercompany borrowings, and drawings under committed bank credit agreements, or commercial paper issuances.

2012 Credit Agreements

On November 14, 2012, Ameren and Ameren Missouri entered into the $1 billion 2012 Missouri Credit Agreement. The 2010 Missouri Credit Agreement was terminated when the 2012 Missouri Credit Agreement when into effect. Also on November 14, 2012, Ameren and Ameren Illinois entered into the $1.1 billion 2012 Illinois Credit Agreement. The 2010 Illinois Credit Agreement was terminated when the 2012 Illinois Credit Agreement went into effect. These facilities cumulatively provide $2.1 billion of credit through November 14, 2017, which date is inclusive of the Ameren Missouri and Ameren Illinois borrowing sublimit extensions discussed below of the maturity date to November 14, 2017, and which may be extended with the agreement of the lenders, subject to the terms of such agreements, for two additional one-year periods. The facilities currently include 24 international, national, and regional lenders, with no lender providing more than $125 million of credit in aggregate.

Schedule MLB-2
Michael Brosch
Page 3

In addition, the 2010 Genco Credit Agreement, under which Ameren was a borrower, was not renewed and was terminated contemporaneously with the effectiveness of the 2012 Credit Agreements.

The obligations of each borrower under the respective 2012 Credit Agreements to which it is a party are several and not joint, and, except under limited circumstances relating to expenses and indemnities, the obligations of Ameren Missouri and Ameren Illinois under the respective 2012 Credit Agreements are not guaranteed by Ameren or any other subsidiary of Ameren. The maximum aggregate amount available to each borrower under each facility is shown in the following table (such amount being such borrower's "Borrowing Sublimit"):

	2012 Missouri Credit Agreement	2012 Illinois Credit Agreement
Ameren	$ 500	$ 300
Ameren Missouri	800	(a)
Ameren Illinois	(a)	$ 800

(a) Not applicable.

Ameren has the option to seek additional commitments from existing or new lenders to increase the total facility size of the 2012 Credit Agreements up to the following maximum amounts: 2012 Missouri Credit Agreement - $1.2 billion; and 2012 Illinois Credit Agreement - $1.3 billion. Each of the 2012 Credit Agreements will mature and expire with respect to Ameren on November 14, 2017, unless extended as described above. Borrowing Sublimits of Ameren Missouri and Ameren Illinois under the applicable 2012 Credit Agreements will mature and expire on November 13, 2013, subject to extension thereof on a 364-day basis, as requested by the borrower and approved by the lenders, or for a longer period upon receipt of any and all required federal or state regulatory approvals, as permitted under the 2012 Missouri Credit Agreement and the 2012 Illinois Credit Agreement, but in no event later than November 14, 2017. Ameren Missouri and Ameren Illinois intend to seek regulatory approval to extend the maturity dates of their respective Borrowing Sublimit under the 2012 Missouri Credit Agreement and the 2012 Illinois Credit Agreement to November 14, 2017. If and when such regulatory approvals are received, no lender approval will be required to effect the extensions. The principal amount of each revolving loan owed by a borrower under any of the 2012 Credit Agreements to which it is a party will be due and payable no later than the final maturity date relating to such borrower under such 2012 Credit Agreements.

The obligations of all borrowers under the 2012 Credit Agreements are unsecured. Loans are available on a revolving basis under each of the 2012 Credit Agreements and may be repaid and, subject to satisfaction of the conditions to borrowing, reborrowed from time to time. At the election of each borrower, the interest rates on such loans will be the alternate base rate ("ABR") plus the margin applicable to the particular borrower and/or the Eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined by the borrower's long-term unsecured credit ratings or, if no such ratings are then in effect, the borrower's corporate/issuer ratings then in effect. Letters of credit in an aggregate undrawn face amount not to exceed 25% of the applicable aggregate commitment under the respective 2012 Credit Agreements are also available for issuance for the account of the borrowers thereunder (but within the $2.1 billion overall combined facility borrowing limitations of the 2012 Credit Agreements).

The borrowers will use the proceeds from any borrowings under the 2012 Credit Agreements for general corporate purposes, including working capital, commercial paper liquidity support, loan funding under the Ameren money pool arrangements or other short-term intercompany loan arrangements, or paying fees and expenses incurred in connection with the 2012 Credit Agreements.

The 2012 Credit Agreements are used to borrow cash, to issue letters of credit, and to support issuances under Ameren's $500 million commercial paper program, Ameren Missouri's $500 million commercial paper program and Ameren Illinois' $500 million commercial paper program. Any of the 2012 Credit Agreements are available to Ameren to support borrowings under Ameren's commercial paper program, subject to borrowing sublimits. The 2012 Missouri Credit Agreement is available to support issuances under Ameren Missouri's commercial paper program, and the 2012 Illinois Credit Agreement is available to support issuances under Ameren Illinois' commercial paper program. As of December 31, 2012, based on letters of credit issued under the 2012 Credit Agreements, the aggregate amount of credit capacity available to Ameren (parent), Ameren Missouri and Ameren Illinois, collectively at December 31, 2012, was $2.09 billion.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2012**

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______to_______

Commission File Number	**Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number**	**I.R.S. Employer Identification Number**
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	43-1916803
000-51873	**KANSAS CITY POWER & LIGHT COMPANY** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange:

Registrant	**Title of each class**	
Great Plains Energy Incorporated	Cumulative Preferred Stock par value $100 per share	3.80%
	Cumulative Preferred Stock par value $100 per share	4.50%
	Cumulative Preferred Stock par value $100 per share	4.35%
	Common Stock without par value	

Securities registered pursuant to Section 12(g) of the Act: Kansas City Power & Light Company Common Stock without par value.

Great Plains Energy's capital requirements are principally comprised of debt maturities and electric utility's construction and other capital expenditures. These items as well as additional cash and capital requirements are discussed below.

Great Plains Energy's liquid resources at December 31, 2012, consisted of $9.3 million of cash and cash equivalents on hand and $ 678.1 million of unused bank lines of credit. The unused lines consisted of $ 186.2 million from Great Plains Energy's revolving credit facility, $ 225.1 million from KCP&L's credit facilities and $ 266.8 million from GMO's credit facilities. See Note 10 to the consolidated financial statements for more information on the revolving credit facilities. Generally, Great Plains Energy uses these liquid resources to meet its day-to-day cash flow requirements, and from time to time issues equity and/or long-term debt to repay short-term debt or increase cash balances.

Great Plains Energy intends to meet day-to-day cash flow requirements including interest payments, retirement of maturing debt, construction requirements, dividends and pension benefit plan funding requirements with a combination of internally generated funds and proceeds from the issuance of equity securities, equity-linked securities and/or short-term and long-term debt. Great Plains Energy's intention to meet a portion of these requirements with internally generated funds may be impacted by the effect of inflation on operating expenses, the level of MWh sales, regulatory actions, compliance with environmental regulations and the availability of generating units. In addition, Great Plains Energy may issue equity, equity-linked securities and/or debt to finance growth.

Cash Flows from Operating Activities

Great Plains Energy generated positive cash flows from operating activities for the periods presented. The $220.8 million increase in cash flows from operating activities for Great Plains Energy in 2012 compared to 2011 is primarily due to an increase in net income, a decrease in pension and post-retirement benefit funding as a result of revised funding requirements, a decrease in deferred refueling outage costs and the payment in 2011 of $26.1 million for the settlement of forward starting swaps (FSS) upon the issuance of $350.0 million of 4.85% Senior Notes in May 2011.

The $109.1 million decrease in cash flows from operating activities for Great Plains Energy in 2011 compared to 2010 is primarily due to a reduction in net income, the payment of $26.1 million for the settlement of FSS upon the issuance of $350.0 million of 4.85% Senior Notes in May 2011, an increase in pension and post-retirement benefit funding and an increase in deferred refueling outage costs, partially offset by the adoption of new accounting rules in 2010. On January 1, 2010, Great Plains Energy adopted new accounting rules for transfers of financial assets, which resulted in the recognition of $95.0 million of accounts receivable pledged as collateral and a corresponding short-term collateralized note payable on Great Plains Energy's balance sheet at December 31, 2010. As a result, cash flows from operating activities were reduced by $95.0 million and cash flows from financing activities were raised by $95.0 million with no impact to the net change in cash in 2010.

Other changes in working capital are detailed in Note 2 to the consolidated financial statements. The individual components of working capital vary with normal business cycles and operations.

Cash Flows from Investing Activities

Great Plains Energy's cash used for investing activities varies with the timing of utility capital expenditures and purchases of investments and nonutility property. Investing activities are offset by proceeds from the sale of properties and insurance recoveries.

Great Plains Energy's utility capital expenditures increased $153.6 million in 2012 compared to 2011 due to an increase in cash utility capital expenditures primarily related to environmental upgrades at KCP&L's La Cygne Station, in addition to normal plant activity.

Great Plains Energy's utility capital expenditures decreased $161.4 million in 2011 compared to 2010 due to a decrease in cash utility capital expenditures primarily related to Iatan No. 2.

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Cash Flows

Year Ended December 31	2012	2011	2010
Cash Flows from Operating Activities		(millions)	
Net income	$ 199.9	$ 174.2	$ 211.9
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	272.3	273.1	331.6
Amortization of:			
Nuclear fuel	24.7	21.4	25.1
Other	36.0	12.7	(4.7)
Deferred income taxes, net	121.2	111.2	123.8
Investment tax credit amortization	(2.4)	(2.2)	(2.9)
Loss from equity investments, net of income taxes	0.4	0.1	1.0
Other operating activities (Note 2)	11.7	(147.5)	(133.7)
Net cash from operating activities	663.8	443.0	552.1
Cash Flows from Investing Activities			
Utility capital expenditures	(610.2)	(456.6)	(618.0)
Allowance for borrowed funds used during construction	(5.3)	(5.8)	(28.5)
Purchases of nuclear decommissioning trust investments	(24.2)	(18.5)	(83.3)
Proceeds from nuclear decommissioning trust investments	20.9	15.1	79.6
Other investing activities	(19.6)	(19.9)	(7.5)
Net cash from investing activities	(638.4)	(485.7)	(657.7)
Cash Flows from Financing Activities			
Issuance of common stock	293.0	5.9	6.2
Issuance of long-term debt	—	747.1	249.9
Issuance fees	(2.9)	(10.7)	(12.1)
Repayment of long-term debt	(513.8)	(598.5)	(1.3)
Net change in short-term borrowings	253.1	16.0	(165.6)
Net change in collateralized short-term borrowings	79.0	—	95.0
Dividends paid	(125.5)	(115.1)	(114.2)
Other financing activities	(5.2)	(6.6)	(7.4)
Net cash from financing activities	(22.3)	38.1	50.5
Net Change in Cash and Cash Equivalents	3.1	(4.6)	(55.1)
Cash and Cash Equivalents at Beginning of Year	6.2	10.8	65.9
Cash and Cash Equivalents at End of Period	$ 9.3	$ 6.2	$ 10.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2012 or

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from to .

Commission file number: 1-3368

THE EMPIRE DISTRICT ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Kansas	**44-0236370**
(State of Incorporation)	(I.R.S. Employer Identification No.)
602 S. Joplin Avenue, Joplin, Missouri	**64801**
(Address of principal executive offices)	(zip code)

Registrant's telephone number: (417) 625-5100

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock ($1 par value)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes_√_ No___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes___ No_√_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes_√_ No___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes _√_No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _√_

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer _√_	Accelerated filer ___
Non-accelerated filer ___ (Do not check if a smaller reporting company)	Smaller reporting company __

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes___ No_√_

The aggregate market value of the registrant's voting common stock held by nonaffiliates of the registrant, based on the closing price on the New York Stock Exchange on June 30, 2012, was approximately $892,694,285.

As of February 1, 2013, 42,535,367 shares of common stock were outstanding.

The following documents have been incorporated by reference into the parts of the Form 10-K as indicated:

The Company's proxy statement, filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, for its Annual Meeting of Stockholders to be held on April 25, 2013	Part of Item 10 of Part III All of Item 11 of Part III Part of Item 12 of Part III All of Item 13 of Part III All of Item 14 of Part III

THE EMPIRE DISTRICT ELECTRIC COMPANY
Consolidated Statements of Cash Flows

	Year Ended December 31, 2012	2011 ($-000's)	2010
Operating activities:			
Net income	$ 55,681	$ 54,971	$ 47,396
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization including regulatory items	71,160	79,751	71,076
Pension and other postretirement benefit costs, net of contributions	1,689	(20,379)	(3,683)
Deferred income taxes and unamortized investment tax credit, net	31,899	45,051	26,880
Allowance for equity funds used during construction	(1,147)	(294)	(4,538)
Stock compensation expense	2,285	2,147	3,478
Non-cash loss on derivatives	4,174	1,187	1,853
Other	(16)	381	-
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(688)	10,342	(11,211)
Fuel, materials and supplies	369	(16,682)	(1,585)
Prepaid expenses, other current assets and deferred charges	(9,238)	(23,163)	(19,606)
Accounts payable and accrued liabilities	(1,297)	(318)	(6,179)
Interest, taxes accrued and customer deposits	875	(980)	1,522
Other liabilities and other deferred credits	3,360	3,172	3,954
SWPA minimum flows payment	-	-	26,564
Accumulated provision – rate refunds	-	(578)	-
Net cash provided by operating activities	159,106	134,608	135,921

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
Consolidated Statements of Cash Flows

	Year Ended December 31, 2012	2011 ($-000's)	2010
Investing activities:			
Capital expenditures – regulated	$ (134,272)	$ (99,162)	$ (106,388)
Capital expenditures and other investments – non-regulated	(2,670)	(3,375)	(2,817)
Restricted cash	(1)	(2,586)	(1,771)
Total net cash used in investing activities	(136,943)	(105,123)	(110,976)
Financing activities:			
Proceeds from first mortgage bonds, net	88,000	-	149,635
Long-term debt issuance costs	(1,074)	-	(1,758)
Proceeds from issuance of common stock, net of issuance costs	8,114	5,884	60,239
Repayment of first mortgage bonds	(88,029)	-	(50,000)
Redemption of trust preferred securities	-	-	(50,000)
Redemption of senior notes	-	-	(48,304)
Net short-term borrowings (repayments)	12,000	(12,000)	(26,500)
Dividends	(42,273)	(26,732)	(51,996)
Other	(934)	(1,754)	(1,356)
Net cash used in financing activities	(24,196)	(34,602)	(20,040)
Net increase (decrease) in cash and cash equivalents	(2,033)	(5,117)	4,905
Cash and cash equivalents, beginning of year	5,408	10,525	5,620
Cash and cash equivalents, end of year	3,375	$ 5,408	$ 10,525

	2012	2011	2010
Supplemental cash flow information:			
Interest paid	$ 38,802	$ 41,088	$ 43,044
Income taxes (refunded) paid, net of refund	(592)	(14,300)	11,264
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ 9,345	$ (1,387)	$ (3,846)
Capital lease obligations for purchase of new equipment	-	29	2,696

The accompanying notes are an integral part of these consolidated financial statements.

Long-Term Debt Payout Schedule (Excluding Unamortized Discount (in thousands)	Payments Due By Period Total	Regulated Entity Debt Obligations	Capital Lease Obligations
2013	$ 98,714	$ 98,415	$ 299
2014	274	-	274
2015	292	-	292
2016	25,307	25,000	307
2017	325	-	325
Thereafter	568,242	565,000	3,242
Total long-term debt obligations	**693,154**	**$ 688,415**	**$ 4,739**
Less current obligations and unamortized discount	1,528		
TOTAL LONG-TERM DEBT	**$ 691,626**		

7. SHORT-TERM BORROWINGS

At December 31, 2012, total short-term borrowings consisted of $24.0 million in commercial paper and no borrowings from our line of credit. During 2012 and 2011 our short-term borrowings outstanding averaged (in millions)

	2012	2011
Average borrowings outstanding	$17.8	$8.8
Highest month end balance	$55.7	$18.5

The weighted average interest rates and the weighted average interest rate of borrowings outstanding at December 31, 2012 and 2011 were:.

	2012	2011
Weighted average interest rate	1.05%	0.98%
Weighted average interest rate of borrowings outstanding	0.91%	0.85%

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from January 26, 2013 to January 17, 2017. The agreement also removes the letter of credit facility and includes a swingline loan facility with a $15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains $150 million, inclusive of the $15 million swingline loan sublimit. In addition, the pricing and fees under the facility were amended. Interest on borrowings under the facility accrues at a rate equal to, at our option, (i) the highest of (A) the bank's prime commercial rate, (B) the federal funds effective rate plus 0.5% or (C) one month LIBOR plus 1.0%, plus a margin or (ii) one month, two month or three month LIBOR, in each case, plus a margin. Each margin is based on our current credit ratings and the pricing schedule in the facility. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility is 1.25%. A facility fee is payable quarterly on the full amount of the commitments under the facility based on our current credit ratings (the fee is currently 0.25%). In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $262,500 in the aggregate. There were no other material changes to the terms of the facility.

The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness to be less than 62.5% of our total capitalization at the end of each fiscal quarter and our EBITDA (defined as net income plus interest, taxes, depreciation and amortization) to be at least two times our interest charges for the trailing four fiscal quarters at the end of each fiscal quarter. Failure to maintain these ratios will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. As of December 31, 2012, we are in compliance with these ratios. Our total indebtedness is 49.9% of our total capitalization as of December 31, 2012 and our EBITDA is 4.9 times our interest charges. This credit facility is also subject to cross-default if we default on in excess of $10 million in the aggregate on our other indebtedness. This arrangement does not serve to legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under this agreement at December 31, 2012. However, $24.0 million was used to back up our outstanding commercial paper.