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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0166

DIRECT TESTIMONY

OF

JOHN J. REED

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
February 2012

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DIRECT TESTIMONY OF JOHN J. REED

CASE NO. ER-2012-0166

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND EMPLOYMENT POSITION.

A. My name is John J. Reed, and I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. and CE Capital Advisors, Inc. (together "Concentric").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this testimony on behalf of Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or the "Company") in this proceeding before the Missouri Public Service Commission ("MoPSC" or the "Commission").

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have more than 35 years of experience in the energy industry, and have worked as an executive in, and consultant and economist to, the energy industry for the past 30 years. Over the past 23 years, I have directed the energy services of Concentric, Navigant Consulting and Reed Consulting Group. I have served as Vice Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to more than 100 energy and utility clients and have provided expert testimony on regulatory, economic and financial matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. My background is presented in more detail in Schedule Nos. JJR-1 and JJR-2.

Q. PLEASE DESCRIBE CONCENTRIC'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A. Concentric provides regulatory, economic, market analysis, and financial advisory services to a large number of energy and utility clients across North America. Our regulatory and economic services include regulatory policy, utility ratemaking (*e.g.*, cost of service, cost of capital, rate design, alternative forms of ratemaking) and the implications of regulatory and ratemaking policies. Our market analysis services include energy market assessments, market entry and exit analyses, and energy contract negotiations. Our financial advisory activities include merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services.

Q. PLEASE DESCRIBE CE CAPITAL'S ACTIVITIES.

A. CE Capital, a wholly-owned subsidiary of Concentric, is a Financial Industry Regulatory Authority ("FINRA") and Securities Investor Protection Corporation ("SIPC") member securities firm that provides services relating to corporate mergers and acquisitions, the valuation of securities, and capital market advisory services.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to discuss the chronic inability of Ameren Missouri to earn what the Commission has determined is a fair return on equity

("ROE") necessary to cover Ameren Missouri's cost of capital and why this fact should be of significant concern to the Commission.

The remainder of my testimony is organized as follows:

- In Section II, I summarize my key conclusions.
- In Section III, I discuss the issues and implications of earnings attrition and regulatory lag and why the Commission should take immediate action to address these issues.
- In Section IV, I describe how the energy industry has fundamentally changed over the past decade and why regulators have, and in the case of the MoPSC should, evolve their ratemaking policies to protect customers by providing utilities with both the timely recovery of costs and the opportunity to earn their allowed returns.
- In Section V, I discuss Ameren Missouri specifically, its business and regulatory environment, history of regulatory lag and earnings attrition, and how, if unaddressed, these issues hurt customers.
- In Section VI, I discuss how the industry at large has addressed these issues and how similar measures, to the extent they are permissible under Missouri statutes, would benefit Ameren Missouri's customers.
- In Section VII, I discuss the importance of the Commission acting in this proceeding to (a) reaffirm and continue Ameren Missouri's existing Fuel Adjustment Clause ("FAC") and trackers, (b) approve the Company's proposed use of Plant-in-Service Accounting and a storm restoration cost

tracker, and (c) consider the level and quality of the Company's earnings when establishing its allowed ROE.

- Finally, in Section VIII, I summarize my conclusions and recommendations.

Q. HOW DOES YOUR TESTIMONY RELATE TO THAT PRESENTED BY OTHER COMPANY WITNESSES?

A. My testimony relates to the testimonies of Company witnesses Baxter, Barnes, Wakeman and Hevert.

Company witness Baxter discusses, among other things, the key drivers of the Company's rate request, some primary challenges facing Ameren Missouri in its efforts to continue to provide safe and reliable service to its customers, and how granting the relief requested in this proceeding is essential to enabling the Company to continue to meet customer expectations and to maintain its financial health. As I will discuss, the Company faces a number of challenges, which if unaddressed will negatively impact its customers.

Company witnesses Barnes and Wakeman discuss the implementation of a two-way storm restoration cost tracker, and Ms. Barnes also discusses "Plant-in-Service Accounting" for non-revenue producing assets (*i.e.*, those not related to customer growth). My testimony focuses on the importance of approving regulatory mechanisms, such as those proposed by Ameren Missouri, so that the Company can reduce regulatory lag and have a better opportunity to earn the ROE that is authorized by the Commission in this proceeding.

Company witness Hevert discusses the appropriate ROE that Ameren Missouri should be authorized to earn. My testimony focuses on the regulatory impediments that exist that deny the Company the opportunity to actually earn whatever return is authorized by the Commission. A fair authorized return and a reasonable expectation that the Company can earn the authorized return are equally important. As I will discuss, under existing Commission policies and practices, the Company is effectively denied the opportunity to earn its authorized return.

II. SUMMARY OF KEY CONCLUSIONS

Q. WHAT ARE YOUR KEY CONCLUSIONS?

A. My key conclusions are:

- Ameren Missouri has been denied the opportunity to earn its allowed return for years. As discussed by Company witness Baxter, in spite of being granted four rate increases in the past 54 months, the Company has never earned its allowed return on a weather normalized basis during this time. Even if one were to ignore the well-established and necessary principle of weather normalization, the Company still earned its allowed return in only 8 of those 54 months.
- This under-earning and need for frequent rate cases is due to the confluence of (1) a fundamentally changed business, economic and regulatory environment, and (2) ratemaking policies in Missouri which have not kept pace with these changes.
- Today's environment is marked by rising costs, of both doing business and complying with regulatory policies, the need for investments in updating and replacing non-revenue producing infrastructure, and stagnating sales. The historic paradigm that revenue growth driven by increased numbers and usage by customers would offset growth in required investment, operating expenses and

capital costs, for at least a reasonable period of time after rates were set, is gone, and frankly has been for some time.

- Regulatory practices (*e.g.*, use of an historic test year, limited use of interim rates) and inactions (*e.g.*, limited employment of expense trackers and only one rate rider, no mechanism to support recovery of capital expenditures in assets placed in service between rate cases) promote regulatory lag and earnings attrition. Ameren Missouri's rates are out of date the moment they become effective and, as a result, the Company is forever denied the opportunity to recover costs it incurs to serve its customers.
- Both a utility's return on and return of capital must be reasonable and fair. Unless its rates are sufficient to generate enough cash to fund operations and investment and recover/earn its allowed return, the utility is firmly put at a disadvantage when competing for capital, its cost of capital increases, and it is forced to delay, defer or outright cancel investments, all to the detriment of customers.
- The majority of other jurisdictions, including Illinois, have addressed these issues through a variety of ratemaking mechanisms. That Missouri's ratemaking practices have not kept pace with the industry at large (1) undermines the Company's ability to support Ameren Corporation's financial condition, putting Ameren Corporation at a disadvantage in raising capital among companies with otherwise commensurate risks, which in turn directly impacts Ameren Missouri and its customers through higher capital costs and less investment; and (2) makes Ameren Missouri a less attractive investment than Ameren Illinois for Ameren Corporation's limited capital.

- I am not indicating that the Company will not live up to its obligations to provide safe and reliable service. But, in order to align its expenditures with the resources provided through the ratemaking process, a utility must prioritize the timing of investments and, in some cases, simply not move forward with certain non-critical investments such as deferring the replacement of aging infrastructure for as long as it reasonably can.
- Ameren Missouri's proposed Plant-in-Service Accounting treatment and storm cost tracker are well-designed to provide the Company with an appropriate means to capture and ultimately have the opportunity to recover certain costs of providing safe and reliable service to its customers that are incurred between test years.
- The Commission's adoption of the Plant-in-Service Accounting treatment and the proposed two-way storm restoration cost tracker will provide Ameren Missouri with a more reasonable opportunity to earn its authorized ROE, and ultimately will benefit the Company's customers through a more reliable electric system at rates that remain among the lowest in the nation.
- I strongly recommend that the Commission approve the Company's proposed Plant-in-Service Accounting treatment and storm cost tracker and continue the Company's existing rider and tracking mechanisms, as well as the 10.75% ROE proposed by Company witness Hevert.

III. REGULATORY LAG AND EARNINGS ATTRITION

Q. WHAT IS REGULATORY LAG?

A. Regulatory lag refers to the delay between the time when a utility incurs costs to serve its customers and when it later recovers those costs through rates. For example, absent offsetting growth in revenues or a reduction in other expenses, when a utility makes an infrastructure investment necessary for safe and reliable service and that investment is not reflected in rate base until a subsequent rate case, there is regulatory lag. In spite of its name, regulatory lag does not refer merely to a delay in the recovery of costs. Costs that cannot be recovered as a result of regulatory lag are lost forever to the utility. Regulatory lag denies a utility the opportunity to earn its allowed ROE, resulting in earnings attrition.

Q. WHAT IS EARNINGS ATTRITION?

A. Put simply, earnings attrition is when a utility's earnings systematically fall below authorized levels which are established based on the "required" cost of capital. The revenue/cost relationship that traditional ratemaking has assumed is that growth in plant investment, operating expenses, capital costs, or a combination of those costs, would, at least for a reasonable period of time after rates are set, be offset by revenue growth. Under those circumstances, utilities have a reasonable opportunity to earn their cost of capital. But when growth in plant investment, operating expenses, capital costs, or a combination of those costs is systematically not offset by revenue growth, indeed when it may be combined with revenue declines, the result is reduced cash flows and a shortfall in the utility's earned return on investment, or equity, or both. This is and has been the case for Ameren Missouri, where shortcomings of the traditional ratemaking construct, compounded by the use of an historic test year and only limited use of other regulatory mechanisms, has resulted in rates which are out of date and insufficient to recover costs the moment those rates become effective.

Q. HAVEN'T REGULATORY LAG AND THE POTENTIAL FOR EARNINGS ATTRITION ALWAYS BEEN PART OF UTILITY RATEMAKING? WHY SHOULD THE COMMISSION BE CONCERNED NOW?

A. As I discuss in more detail in Section IV of my testimony, the energy industry has fundamentally, and for the foreseeable future likely permanently, changed. In the past, technological improvements were driving unit costs down, at the same time that load growth was increasing revenues. As a result, costs to serve customers were declining in some cases and revenue growth was able to keep pace with cost growth where it occurred. Today, the exact opposite is true. The industry is in an environment of rising costs and essentially flat or declining sales volumes per customer. The utility is forced to seek rate relief over and over again to simply attempt to maintain the status quo without consideration of the expansion in capital expenditures required to meet reliability, service quality, environmental and societal objectives. And, absent ratemaking treatment which provides a utility with the timely recovery of costs and a fair opportunity to earn its allowed return, the regulatory compact between regulators and utilities no longer functions as originally intended and as relied upon by customers and investors. The Edison Electric Institute ("EEI") commented on this situation in one of its financial updates for the third quarter of 2011:

> [L]ag obstructs utilities' ability to earn their allowed return when costs are rising. As a result, lag can ultimately increase utilities' borrowing

> costs. Commissions and state legislatures can support utilities' financial health and help curb future rate increases by helping utilities reduce lag.[1]

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE REGULATORY COMPACT AS IT PERTAINS TO THE RETURN OF AND RETURN ON INVESTMENT AND WHY MAINTAINING THAT COMPACT IS IMPORTANT.

A. Each participant in the regulatory relationship has certain interrelated responsibilities, the satisfaction of which is critical for the regulated utility industry to function effectively and for its customers to benefit from safe and reliable service now and over the long term. Utilities must provide their customers with safe, reasonably priced and reliable service. Regulators must provide utilities with a fair and reasonable opportunity to recover their costs to serve their customers, including a compensatory ROE. Customers pay the rates approved by the regulator. Investors provide capital, debt and equity, at rates commensurate with investments of comparable risk and opportunity. When any leg of this stool wobbles, it impacts the other legs. For example, when a utility is deprived a reasonable opportunity to earn its allowed return: (1) the utility is forced to seek frequent rate relief to attempt to maintain the *status quo* and, as I describe in more detail later in my testimony, to defer expenditures; (2) investors will require higher returns – both debt and equity – to compensate them for this regulatory risk; (3) customers will face commensurately

[1] EEI Quarterly Report of the U.S. Shareholder-Owned Electric Utility Industry, Rate Case Summary, Q3 Financial Update, at 2.

higher costs and other implications of the utility deferring expenditures; and (4) regulators will constantly be playing catch-up in the ratemaking process.

Q. PLEASE EXPAND UPON THE ADDITIONAL RISK AND COSTS REGULATORY LAG AND EARNINGS ATTRITION PLACE ON CUSTOMERS AND WHY THE COMMISSION SHOULD TAKE ACTION IN THIS PROCEEDING.

A. Systemic and chronic regulatory lag and earnings attrition do not support or encourage investment in the utility, and investment by the utility in its system. In fact, absent specific ratemaking initiatives to address regulatory lag, this situation outright discourages investment - every dollar spent on non-revenue producing investments (*e.g.*, infrastructure updating) between test years earns no return after the plant goes in service and results in immediate depreciation expense that serves to reduce earnings. This tells a utility to postpone discretionary but prudent capital projects, or forgo them altogether. Further, when the amount of cash coming in is insufficient to fund operations because rates are not adequate, management may be forced to adjust operating practices to bring spending in line with the cash it collects from its customers.

As discussed in more detail by Company witness Hevert, it also significantly affects both a utility's access to and cost of capital, which in turn increases customers' rates. In discussing the predictability and stability of the regulatory framework, Moody's Investors Service ("Moody's") observes:

> In evaluating the predictability of cash flows, we are concerned less with the awarded ROE, which has a tendency to become a headline, than the overall collective rate outcome, including the authorized base rate increase, the impact of any approved enhanced cost recovery

> mechanisms such as riders or trackers, and the implications for future cash flows. We observe that the amount of regulatory lag can be a contributing factor to a utility not being able to earn that authorized rate of return. From a credit perspective, while we are also less concerned with shareholder returns, we do observe that those companies that earn at or near their authorized return tend to produce more predictable cash flows; and those companies that are not able to earn their authorized return tend to produce relatively weaker cash flow credit metrics.[2]

As the Moody's comment suggests, investors recognize that a reasonable allowed ROE that is subject to earnings degradation or "attrition" due to unfavorable regulatory or economic factors does not provide any assurance that the company will actually recover its costs or earn a reasonable return. Investors look not only at the level of authorized return but the regulatory policies that are in place to protect the utility's ability to earn its allowed return, or the quality of its earnings, and consider the combination of the two in evaluating competing utility investments.

Q. WOULDN'T SIMPLY INCREASING A UTILITY'S ALLOWED ROE ADDRESS THESE ISSUES?

A. No, not necessarily. While the authorized return sends an important signal to investors regarding the extent of regulatory support for financial integrity, the ability to recover costs and reinvest in the company, and financial growth, the real focus of investors' analysis is the actual earned return, and earnings attrition undermines the financial community's confidence in the regulatory process. The United States Supreme Court's *Hope* and *Bluefield* cases, which established the standards for determining the fairness or reasonableness of a utility's allowed ROE, spoke to this

[2] Moody's Investor Service, Regulatory Frameworks – Ratings and Credit Quality for Investor Owned Utilities, Evaluating a Utility's Regulatory Framework, June 18, 2010, at 10-11.

point - namely that the specific means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.[3] A regulator must establish rates at a level that allows the utility to generate cash flow sufficient to embark on capital initiatives while maintaining its business operations. Deficiencies in the allowed return or in the utility's ability to earn its return can have significant negative impacts on the utility's cash flow, earnings and ability to attract capital at reasonable rates.

Q. PLEASE EXPAND UPON INVESTMENT PRINCIPLES AND THEIR IMPLICATIONS FOR UTILITY RATEMAKING.

A. Two fundamental principles are at play – capital attraction and capital allocation. Investors will place their finite pool of capital with the investments which offer the best return, best being defined in consideration of return opportunity, earnings quality and risk. If a utility is not afforded the opportunity to earn its allowed return (or if allowed returns do not reflect the true cost of equity for the utility), rates are not just and reasonable, and the utility's ability to attract capital is hurt. Investors, be they shareholders in a publicly traded company or the parent of a utility affiliate, will simply allocate their investment capital elsewhere.

Q. HOW DO THE PRINCIPLES OF CAPITAL ATTRACTION AND CAPITAL ALLOCATION IMPACT AMEREN MISSOURI AND ITS CUSTOMERS?

A. If the Commission authorizes a competitive ROE but then allows it to be eroded by regulatory lag, this undermines Ameren Missouri's ability to support Ameren Corporation's financial condition. This in turn impacts Ameren Corporation's ability

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3 *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

to raise (or the cost at which it raises) capital from its shareholders -- mutual funds, pension funds, ordinary individuals. If Ameren Corporation is at a disadvantage in raising capital among companies with commensurate risk because the companies it owns are underperforming, this directly impacts Ameren Missouri and its customers through higher capital costs, less internally generated cash to fund operations, and less investment. This is especially problematic given the earnings attrition Ameren Missouri is already experiencing in its normal operations where costs are increasing while sales are not, and rates created during the historical test year will be inadequate to provide for both cost recovery and the opportunity to earn the allowed ROE in future periods.

In addition, it should be noted that Illinois, where Ameren Corporation's other regulated utility subsidiary operates, recently passed "formula rate plan" legislation impacting the electric business. The legislation implements a number of techniques to reduce regulatory lag. First, the legislation reduces the period of time the Commission has to review rate filings. Second, the legislation provides greater certainty regarding the utility's ability to recover its costs. Third, the legislation encourages investment in the utility's infrastructure aimed at improving system reliability. Finally, the legislation provides assurance regarding the utility's ability to earn its established return on its investments. Absent the MoPSC addressing the issues of timely cost recovery and a fair opportunity for Ameren Missouri to earn its allowed ROE, the Illinois legislation will have the effect of making Ameren Illinois a significantly better place for Ameren Corporation to invest its limited capital than Ameren Missouri, and that is the kind of investment that Ameren Corporation's shareholders will demand, or else they will take their money elsewhere. If that happens, Ameren Corporation will either have greater difficulty raising capital or will have to do so at a higher cost, in either case negatively impacting Ameren Missouri and its customers.

Q. ARE YOU SUGGESTING THAT A UTILITY'S INVESTORS MUST BE GUARANTEED THE ROE AUTHORIZED BY ITS COMMISSION?

A. Not at all. Equity investors need not be guaranteed a specific return on their investment, but they should have a fair and reasonable opportunity to realize a compensatory return. If a utility does not have a fair and reasonable opportunity to earn its allowed ROE, particularly in a time of elevated capital expenditures and tepid sales, the utility will have more difficulty attracting capital at reasonable terms to continue to fund investments required to provide safe and reliable service at affordable rates. Ultimately, this is detrimental to customers.

IV. BUSINESS AND REGULATORY ENVIRONMENT

Q. PLEASE DISCUSS THE BUSINESS ENVIRONMENT IN WHICH UTILITIES CURRENTLY OPERATE.

A. The business environment in which utilities operate has two major drivers – economic and regulatory. The economic environment is a product of the broader U.S. economy. The U.S. economy is continuing its sustained but tempered recovery from the recession of 2007-2009. While the economy has grown and is expected to continue to grow, the pace of recovery is expected to continue to be modest in the near term. And, as I discuss in Section V of my testimony, the Missouri economy is even weaker. Table 1, below, highlights the lethargy of some of the principal economic indicators which demonstrate the severity of the recent recession and the modest recovery.

Table 1: Economic Indicators – 2005 through 2012

Year	Real GDP Growth[4]	Annual Unemployment Rate[5]	Annual Housing Starts[6]	Industrial Production[7]	Annual Vehicle Sales (million)[8]	Price of Industrial Commodities[9]
2005	3.1%	5.1%	2,068,300	95.3	17.44	8.5%
2006	2.7%	4.6%	1,800,900	97.4	17.05	5.4%
2007	1.9%	4.6%	1,355,000	100.0	16.46	3.7%
2008	(0.3%)	5.8%	905,500	96.3	13.49	9.8%
2009	(3.5%)	9.3%	554,000	85.5	10.60	(9.1%)
2010	3.0%	9.6%	587,600	90.1	11.77	7.0%
2011	1.7%	9.0%	607,000	95.3	12.70	7.1%
2012[10]	2.2%	8.7%	710,000	98.3	13.70	N/A

Q. HOW HAS THE GENERAL ECONOMY AFFECTED THE ELECTRIC UTILITY SECTOR?

A. Generally speaking, costs in the electric utility sector are on an increasing trajectory due to both increases in fundamental expenses and increasing capital expenditure needs. This is a phenomenon that we have seen for the last several years, and is one that is expected to continue. This is in part because the industry is faced with aging infrastructure, an aging workforce, increasing costs due to global demand for fuel and

[4] Source: Bureau of Economic Analysis. 2011 figure is based on preliminary estimate of fourth quarter growth in real GDP, released January 27, 2012.
[5] Source: Bureau of Labor Statistics.
[6] Source: National Association of Home Builders, Annual Housing Starts (1978-2011), based on data provided by U.S. Census Bureau.
[7] Source: Federal Reserve Board, Industrial Production and Capacity Utilization, 2011 Annual Revision, March 25, 2011, at 17.
[8] Source: Ward's Automotive Research.
[9] Source: Bureau of Labor Statistics, Producer Price Index, Price of Industrial Commodities, (1982 = 100)
[10] Source: Blue Chip Economic Indicators, January 1, 2012, at 2.

raw materials, rising medical costs, and ongoing cost and uncertainty regarding ever-more-stringent environmental and other regulations.

As noted by Company witness Baxter, Ameren Missouri's normal costs of serving its customers (*i.e.*, labor and materials, fuel) continue to be subject to steady increases, outpacing revenues. Further, capital expenditures are increasingly necessary to replace aging infrastructure, comply with environmental regulations, ensure reliability of service, promote energy efficiency, and modernize the system. Importantly, these capital expenditures are not related to customer growth, and do not result in increased revenues for Ameren Missouri.

Q. PLEASE DISCUSS THE REGULATORY ENVIRONMENT IN WHICH UTILITIES OPERATE.

A. On a macro level, the U.S. electric utility regulatory environment is evolving. Over the past several years, focus has increased on energy efficiency and conservation, renewable energy resources and environmental sustainability, and "smart" technologies. Environmental compliance requirements have also increased. At the same time, ratemaking policies in many jurisdictions have evolved. Mechanisms decoupling revenues from volumes sold, lost revenue adjustment mechanisms, forward looking test years, formula rates, and various cost trackers and pass-through mechanisms (riders) are now widely employed. In most cases, these alternative ratemaking mechanisms have been put in place to deal specifically with regulatory lag and earnings attrition, which addresses the longer-term policy issues associated with making much needed investments in aging infrastructure. I discuss the prevalence of these mechanisms as well as specific examples in more detail in Section VII of my testimony.

Q. HOW IMPORTANT IS IT THAT THE STATE REGULATORY ENVIRONMENT BE SUPPORTIVE OF A UTILITY'S OPERATIONS AND PROVIDE THE OPPORTUNITY FOR TIMELY COST RECOVERY?

A. As described in more detail by Company witness Hevert, regulatory risk is a critical factor. Moody's, for example, notes:

> The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.[11]

Put simply, utilities that operate in a supportive regulatory and ratemaking environment, marked by reasonable and predictable returns and timely recovery of costs, are considered less risky, which in turn increases their access to and reduces their cost of debt and enables to them to deliver better service through greater investments in their systems than those utilities which lack this kind of regulatory support.

[11] Moody's Global, Infrastructure Finance, *Rating Methodology, Regulated Electric and Gas Utilities*, August 2009, at 7.

Q. HAVE UTILITIES MODIFIED THEIR BUSINESS PRACTICES IN LIGHT OF THE CURRENT ENVIRONMENT?

A. Yes. The economic slowdown has prompted utilities across the country, including Ameren Missouri, to revise capital expenditure forecasts downward by deferring discretionary projects until it is reasonable to be confident that the economy is entering a period of sustained recovery. But, make no mistake, this slowdown in capital spending is not just due to economic conditions. Utilities that are not provided with the timely recovery of costs and a reasonable opportunity to earn a fair and compensatory return are forced to slow investment in infrastructure even more, making only necessary expenditures and delaying, deferring or eliminating other investments which would, if made, benefit customers.

In the case of Ameren Missouri, Moody's has noted that the Company's "capital expenditures moderated to the $600 million range in 2010 from nearly $900 million in 2008 and 2009 as the Company reduced and postponed capital expenditures for its distribution system, power plant improvement, and other purposes."[12] In fact, while the electric utility industry at large is projected to make capital expenditures in the range of two times depreciation expense over the next five years, Ameren Missouri's capital expenditures have declined to approximately 1.5 times depreciation expense and are expected to decline further.

Barclay's Capital commented in its survey of utility industry capital spending that:

> On average spending is projected to be 5-6% higher in 2010-2011 versus our survey a year ago, with the biggest increases by far in environmental investments. Overall, we are projecting capital

[12] Moody's Investor Service, Credit Opinion: Union Electric Company, August 12, 2011, at 2.

> spending at regulated utilities of $351 billion over the next five years. This would be about 2x the depreciation rate, which is consistent with recent trends.[13]

This means that internal cash flows from operations are insufficient to fund planned capital expenditure projects. As projects that were deferred in response to economic conditions become higher priorities over time, and as capital spending increases, there will be a significant need to access capital markets. This reliance on capital markets occurs against a backdrop of greater levels of conservation and an intensified focus on energy efficiency, which serve both to depress demand per customer and, ultimately, to squeeze cash flows. Without offsetting improvements in the ratemaking process, this increases capital costs and also creates the need for serial rate cases.

Q. PLEASE SUMMARIZE THE IMPLICATIONS FOR A UTILITY'S CUSTOMERS IF A UTILITY IS DENIED TIMELY COST RECOVERY.

A. If a utility is denied timely recovery of costs, particularly in a period of rising costs and investment needs, cash recovered from customers is insufficient to fund operations and the utility is denied the opportunity to earn its allowed return which in turn damages its financial health and negatively impacts its customers. When a utility's rates are consistently insufficient and it is denied the opportunity to earn a fair return, it necessarily must consider adjusting operating practices and deferring capital projects which otherwise would be beneficial to its customers and the community. This is not to suggest that a utility would not satisfy its obligations to provide safe and reliable service; rather, that in order to align its expenditures with

[13] *U.S. Utilities: Capital Appreciation*, Barclay's Capital Equity Research, June 24, 2010, at 7-9.

the resources it is provided, it must prioritize the timing of investments and, in some cases, simply not move forward with certain non-critical investments, such as delaying the replacement of aging infrastructure for as long as it reasonably can.

In addition, the consisten inability to earn a fair return increases a utility's cost of capital, resulting in higher costs to customers. By putting downward pressure on its stock price, the cost of equity is increased. In addition, the utility's debt rating will suffer. And when internally generated cash flows are insufficient to fund operations, the need to seek external sources of capital is increased. Accordingly, interest expenses and the cost of equity capital borne by customers increase.

V. AMEREN MISSOURI

Q. BESIDES MISSOURI'S RATEMAKING PRACTICES, WHAT HAS CONTRIBUTED TO AMEREN MISSOURI'S CHRONIC INABILITY TO EARN ITS ALLOWED RETURN?

A. In the late 1950s to early 1970s the Company experienced significant growth in both the number of customers (*e.g.*, housing development) and the usage per customer (*e.g.*, the advent of air conditioning). This growth necessitated large infrastructure investments. Those investments in the 1970s through 1990s generally supported the Company's earnings, and as they were depreciated the Company's overall cost structure declined (except, primarily, as it related to the initial cost of the Callaway nuclear plant). Electricity demand also continued to grow. Much of the equipment installed during those growth years now requires replacement or upgrade in order to continue to provide safe and reliable service to customers. Further, capital investment in assets that provide service, including those required to comply with legislative mandates (including environmental and renewable energy laws), as noted by Company witness Baxter, comprise approximately $85 million of the Company's requested rate relief in this case.

Q. HOW DOES THIS IMPACT THE COMPANY AND ITS CUSTOMERS?

A. This fact, in concert with ratemaking practices in Missouri which have not kept pace with the changes in the energy industry, represents the major challenge to Ameren Missouri as it continues to strive to uphold its part of the regulatory compact. Ameren Missouri has an obligation to provide safe, adequate and reliable service to its customers. Ameren Missouri needs to deploy significant infrastructure development capital to do so. Sales volumes are essentially flat and not expected to rebound in a manner sufficient to compensate for non-revenue producing capital invested. In addition, enhanced energy conservation and efficiency trends that are observed across the electric utility industry will place additional and considerable downward pressure on demand. As a result, the Company cannot adequately recover costs through rates and earn sufficient revenue to compensate its investors on a reasonable and timely basis. As discussed earlier in my testimony, customers then face the effects of both the inability for the Company to invest in infrastructure improvements and increases in costs.

Q. HOW HAS AMEREN MISSOURI RESPONDED TO THESE CHALLENGES?

A. As discussed in Company witness Baxter's testimony, the Company has controlled costs where it can, and in general has taken steps to align its spending with the revenues provided by the rates the Commission has previously approved and economic conditions. However, in the face of investment needs that exceed depreciation by a substantial margin, and upward pressure on other costs, the ability to continue to align the Company's expenditures in this fashion will either not exist, or it will require a substantial decrease in investment at the very time when maintaining or even increasing investment is needed to address the aging infrastructure about which I spoke earlier. And even with the Company's cost control efforts, the Company continues to struggle to earn a fair return, which as I also noted earlier, in turn creates a quite understandable reluctance to continue to invest, even where investment ought to be in the long-term interests of the Company and customers alike.

Q. EARLIER IN YOUR TESTIMONY YOU DISCUSSED THE INFLUENCE OF THE ECONOMIC ENVIRONMENT ON A UTILITY'S OPERATIONS. WHAT IS THE ECONOMIC ENVIRONMENT IN AMEREN MISSOURI'S SERVICE TERRITORY?

A. More than half of the Company's customers reside in the St. Louis Metropolitan Area. The Federal Reserve Bank of St. Louis ("St. Louis Fed") reports that economic activity in the St. Louis Metropolitan Statistical Area, which includes both Missouri and Illinois, has been slower to recover from the 2007-2009 recession than the rest of the nation. Specifically, the report states:

> For several quarters before the national recession, which started in the last quarter of 2007, Illinois' personal income growth was roughly similar to the nation's, while Missouri's was slightly lower. The recession's impact on personal income in Missouri and Illinois was stronger than in the nation. The recovery (since 2010) has been generally weaker in both states compared with the nation. Between the second quarter of 2010 and the second quarter of 2011, personal

> income grew 2.1 percent in Missouri and 3.2 percent in Illinois, respectively, while it grew 2.9 percent for the nation as a whole.[14]

The St. Louis Fed report also assesses the outlook for economic activity, using the Philadelphia Federal Reserve's coincident index, which combines information on payroll, employment, wages, unemployment and hours of work to give a single measure of economic performance. In that regard, the report notes:

> The coincident indexes for both Illinois and Missouri reveal a stronger impact of the recession and a slower recovery in these states compared with the nation. The index bottomed out at 89.5 for Illinois and at 87.6 for Missouri, while it bottomed out at 92.1 for the nation. Current values of the index suggest that economic activity in Illinois is at 93.4 percent of its pre-recession level, while it is at 89.8 percent in Missouri and 96.3 percent in the nation. Despite the large difference in the recovery of economic activity between Missouri and the nation ... during the last half of 2011, economic activity in Missouri has begun to increase appreciably.[15]

However, the Federal Reserve in November 2011 stated: "Overall economic activity increased at a slow to moderate pace since the previous report across all Federal Reserve Districts except St. Louis, which reported a decline in economic activity."[16]

Q. HOW DOES THE MISSOURI REGULATORY ENVIRONMENT COMPARE TO OTHER JURISDICTIONS?

A. As noted by Company witness Hevert, Ameren Missouri's regulatory risks are notably higher than those of the proxy group of companies he relied upon to establish the Company's proposed ROE. As discussed in more detail in Mr. Hevert's testimony, Standard and Poor's ("S&P") ranks regulatory jurisdictions in one of five

[14] Current Economic Conditions in the Eighth Federal Reserve District, St. Louis Zone, Research Division of the Federal Reserve Bank of St. Louis, December 23, 2011, at 5.
[15] Ibid, at 3.
[16] Summary of Commentary on Current Economic Conditions by Federal Reserve District, U.S. Federal Reserve Board, November 30, 2011, at i.

categories from most credit supportive to least credit supportive. S&P ranks the regulatory environment in Missouri as "less credit supportive," which is the second lowest ranking. Only four jurisdictions (*i.e.*, Arizona, Delaware, the District of Columbia, and New Mexico) are ranked lower than Missouri.[17]

This level of increased regulatory risk is influenced by the issues I am discussing here – regulatory lag and earnings attrition. The fact that the Company must use a historical test year when establishing rates, has only a single rider, the FAC, to provide for real time cost recovery, has only a few targeted trackers, and, at this time, has no mechanism for mitigating the impact on its earnings from additions made to rate base between rate cases, contributes to regulatory risk that is significantly higher than that of most jurisdictions. As I discuss in more detail in Section VII of my testimony, Missouri has simply not kept pace with the rest of the industry.

Q. HOW DOES THE USE OF A HISTORICAL TEST YEAR SPECIFICALLY IMPACT AMEREN MISSOURI?

A. Using this rate filing as an example, the Company is employing a test year for the twelve months ended September 30, 2011. Rate base reflects the prudent investments made in the Company's generation, transmission, distribution and general and intangible plant since the end of the true up period in the Company's last case (*i.e.*, March 2011). The Company will not be able to commence earning a return on these assets until the rates approved in this proceeding go into effect, essentially at the beginning of 2013. Therefore, the Company will be denied the ability to earn a return on over $700 million of assets it anticipates placing in service between March 2011

[17] Standard and Poor's Updates its U.S. Regulatory Assessments, Standard and Poor's, April 12, 2010, at 1-2.

and the end of the true-up period (proposed to be July 31, 2012). In addition, the Company will absorb the incremental depreciation expense on these assets during this time frame.

Q. DOESN'T THE COMMISSION'S ALLOWANCE OF UPDATING UTILITY PLANT IN SERVICE DURING A RATE CASE ADDRESS REGULATORY LAG?

A. Only to a very limited degree. This practice allows for the inclusion in rate base – and *prospective recovery in rates* -- plant that is placed in service up to a certain point (typically about 6 months into an 11-month proceeding), if the Company has an active rate proceeding. However, it fails to capture costs associated with non-revenue producing investments that begin serving customers during the remaining approximately five months, and it completely fails to capture those costs for non-revenue producing investments made between proceedings. As noted in the testimony of Company witness Barnes, Ameren Missouri estimates that the lost return and depreciation expense will total approximately $15 million for assets placed in service between the end of the true-up period from the last rate case (March 2011) and the end of 2011. As Ms. Barnes also indicates, that number could easily double by the time further in-service investments made through the end of the Company's proposed true-up period in this case are reflected in rates in January 2013. Again, the opportunity for the Company to recover these costs is not simply delayed, it is lost forever.

Q. HAS AMEREN MISSOURI BEEN DENIED THE OPPORTUNITY TO EARN ITS AUTHORIZED RATE OF RETURN?

A. Yes. As shown in Company witness Baxter's testimony, since June 2007, Ameren Missouri has been granted four rate increases. Despite these increases, on a weather-normalized basis based on a rolling 12-month average, the Company has failed to earn its authorized return in even a single month from June 2007 through November 2011. The shortfall between authorized and earned rates of return has ranged from approximately 60 basis points to over 450 basis points over the 4+ year period. On average the shortfall has been approximately 260 basis points. Even if we were to not consider the well-established principal of weather normalization, the Company still failed to earn its allowed return in just 46 of the 54 months of this period. This extraordinary failure is directly attributable to regulatory lag, which in turn is directly attributable to the failure of the ratemaking approaches historically used in Missouri to give the Company a reasonable opportunity to earn its allowed return.

Q. HAVE CREDIT RATING AGENCIES COMMENTED ON THE EFFECTS OF REGULATORY LAG ON AMEREN MISSOURI'S ABILITY TO EARN ITS AUTHORIZED RETURN?

A. Yes. Moody's recently addressed the impact that regulatory lag has on Ameren Missouri's earnings in a credit rating report, as follows:

> Union Electric operates in what Moody's has considered to be a below average regulatory framework, which has resulted in significant regulatory lag and prevented the utility from earning its allowed return on equity. Factors contributing to Moody's below average regulatory assessment include lengthy 11 month base rate case timelines; the lack

> of interim rate relief; the use of historical test years; and less than full recovery of fuel costs.[18]

Similarly, S&P notes that regulatory commissions should eliminate, or at least greatly reduce, the issue of rate-case lag.[19]

Q. WHAT ARE YOUR CONCLUSIONS REGARDING AMEREN MISSOURI'S BUSINESS AND REGULATORY RISKS?

A. Like many electric utilities today, the Company's costs are increasing while sales volumes are static or decreasing. Given the incremental costs associated with a variety of items, including increased energy efficiency, potential carbon regulation and mitigation, compliance with regulations such as the Maximum Allowable Toxicant Content ("MATC") rules and the Cross-State Air Pollution Rule ("CSAPR"), system hardening, implementation of smart grid, reliability enhancement, and a general increasing trend of operations and maintenance expenses, weather-normalized revenues are increasingly insufficient to ensure cost recovery in the traditional ratemaking paradigm still being used in Missouri. This means that Missouri ratemaking practices have not kept up with the industry at large, making it a less attractive place for investment. As a result, customers face increased risk due to delayed capital expenditures and increased costs.

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[18] Moody's Investor Service, Credit Opinion: Union Electric Company, August 12, 2011, at 2.

[19] Standard and Poor's, *Assessing Vertically Integrated Utilities' Business Risk Drivers*, U.S. Utilities and Power Commentary, November 2006, at 10.

VI. THE COMPANY'S PROPOSED COST RECOVERY MECHANISMS

Q. YOU'VE DISCUSSED REGULATORY LAG THAT LEADS TO EARNINGS ATTRITION. WHAT CAN THE COMMISSION DO TO ADDRESS THIS PROBLEM?

A. As I discuss in detail below and as I alluded to earlier, there are many tools utilized in other jurisdictions to address the systemic problems associated with earnings attrition. Because of Missouri statutes, some of those tools are not available in Missouri. However, the Commission does have tools at its disposal, including continuation of the Company's FAC and cost trackers for vegetation management and infrastructure inspection, pension/OPEB costs, and FIN 48 tax liability. The Commission can and should employ the other tools Ameren Missouri is proposing in this case, namely the Company's proposed use of "Plant-in-Service Accounting" for non-revenue producing capital investments and the two-way storm cost restoration cost tracker. In fact, since many of the utilities with whom Ameren Missouri (and its parent, Ameren Corporation) must compete for capital operate in jurisdictions that have at their disposal more tools than available in Missouri, it is even more important that Missouri use the tools that it does have to address the chronic and systemic earnings attrition being experienced by Ameren Missouri.

Q. PLEASE DESCRIBE THE ADDITIONAL MECHANISMS AMEREN MISSOURI IS PROPOSING TO ADDRESS THE TIMELY RECOVERY OF ITS COSTS.

A. As discussed more fully in the testimony of witnesses Barnes and Wakeman, Ameren Missouri is proposing a two-way storm restoration cost tracker and as Ms. Barnes discusses, is also proposing a Plant-in-Service Accounting treatment for non-revenue producing investments that are serving customers but which are not yet in rate base.

Q. HAVE YOU REVIEWED THESE MECHANISMS?

A. I have. Each of them is well-designed to provide the Company with an appropriate means to capture and ultimately have the opportunity to recover certain costs of providing safe and reliable service to its customers that are incurred between test years.

Q. ARE MECHANISMS LIKE THESE COMMONLY USED IN THE INDUSTRY?

A. Yes. As I discuss in Section VII of my testimony, measures to reduce regulatory lag and mitigate earnings attrition are widely used in the utility industry. Ameren Missouri has proposed appropriate measures here which are permissible under existing Missouri legislation, and, if approved, will provide benefits similar to those that are discussed in Section VII. By approving the proposed measures, which are modest by comparison to some that have been approved and implemented in other states, the Commission would be taking an important step toward providing regulatory support for Ameren Missouri in this new era of utility regulation.

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE NEW PLANT-IN-SERVICE ACCOUNTING TREATMENT PROPOSED BY AMEREN MISSOURI IN THIS CASE.

A. As described in more detail in the testimony of Company witness Barnes, the Company is requesting that the Commission grant it accounting authority for investment in non-revenue producing plant to (1) accrue for lost return on its investment (offset by retirements and changes to the accumulated depreciation reserve) at its Commission-approved weighted average cost of capital, (2) defer depreciation expense for all non-revenue producing assets (offset by retirements) placed in service between rate cases, and (3) record these amounts as a regulatory asset. At the time of the Company's next rate case, the Company would propose to place these deferred expenses into its rate base for amortization over the lives of the assets.

Q. WHY IS PLANT-IN-SERVICE ACCOUNTING TREATMENT FOR NON-REVENUE PRODUCING ASSETS NECESSARY?

A. As I described earlier in my testimony, under the existing regulatory framework the Company cannot recover the costs, both return and depreciation expense, that it incurs on behalf of customers between rate cases to provide them with safe and reliable service. In other words, as things currently stand, the Company cannot recover the full cost of its investment in capital assets. This violates the regulatory compact, provides a disincentive to the Company to invest in its system, and is harmful to customers. As noted by witness Barnes, this will result in approximately $15 million of lost recovery for the Company during the period from March 2011 to December 2011, a figure that could easily double by the time new rates from this case take effect in early 2013.

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE NEW TWO WAY STORM RESPONSE COST TRACKER PROPOSED BY AMEREN MISSOURI IN THIS CASE.

A. As described in more detail in the testimony of Company witnesses Barnes and Wakeman, the Company is requesting that the Commission approve (1) the inclusion in the Company's revenue requirement of a base level of non-internal labor operations and maintenance ("O&M") costs applicable to restoration of service following major storms, (2) a tracker comparing actual major storm-related O&M expenses (excluding internal labor) to the base level of expense included in rates, and (3) the creation of regulatory assets (when the actual level of major storm expenses exceeds the tracker base) or liabilities (when actual major storm restoration expenses are less than the tracker base). At the time of the Company's next rate case, the Company would include these regulatory assets or liabilities in the Company's revenue requirement with the intention of having them reflected in the Company's rates, and amortized over a reasonable period, as proposed by the Company at that time.

Q. WHY IS A STORM COST TRACKER APPROPRIATE?

A. As the Commission has recognized, major storms are unpredictable and storm restoration costs can vary greatly from year-to-year. The storm cost tracker provides the Company with the opportunity to recover costs it must incur to restore safe and reliable service to its customers following a major storm, and protects customers by ensuring the Company recovers only the level of costs incurred.

Q. WILL THESE MECHANISMS BENEFIT THE COMPANY'S RATEPAYERS?

A. Yes. The Plant-in-Service Accounting and the two-way storm restoration cost tracker will provide regulatory efficiencies that ultimately benefit customers through (1) a reduced cost of service, and (2) helping to reduce pressure to limit or reduce investments in the Company's system. More timely cost recovery will allow the Company to attract capital at reasonable rates. As noted earlier in my testimony and in the testimony of Company witness Baxter, this is particularly important given the Company's capital expenditure plans. Providing Ameren Missouri with the opportunity to earn its allowed return will improve the Company's cash flows, enabling it to invest in its system and infrastructure to facilitate long-term safe and reliable service.

These measures will provide Ameren Missouri with a more reasonable opportunity to earn its authorized ROE, and ultimately will benefit the Company's customers through a more reliable electric system at rates that remain among the lowest in the nation.

VII. RATEMAKING SOLUTIONS

Q. EARLIER YOU MENTIONED THAT THE RISKS OF REGULATORY LAG AND EARNINGS ATTRITION ARE BEING ADDRESSED THROUGH RATEMAKING AND REGULATORY POLICIES IN MANY JURISDICTIONS. PLEASE EXPLAIN

A. Utilities and regulators alike are finding innovative solutions to address this new paradigm of increasing costs and declining use per customer, including those associated with the substantial capital investment needs to address aging infrastructure issues and comply with environmental mandates. For example, revenue-stabilizing alternative regulation plans have emerged and are becoming increasingly prevalent as an accompaniment to energy efficiency programs, where declining usage is an objective. My understanding is that Ameren Missouri is proposing mechanisms that will enable it to recover its energy efficiency related costs in its Missouri Energy Efficiency Investment Act filing now pending at the Commission. Frequently, electric utilities adopt alternative regulatory mechanisms, since the utility is no longer able to offset its increased capital requirements with increasing sales. These mechanisms may take a variety of alternative forms such as the implementation of a forecast test year, revenue decoupling, straight-fixed variable rate design, comprehensive cost recovery riders, capital expenditure recovery or deferral mechanisms or annual revenue requirement true-ups. Schedule No. JJR-3 provides a summary of these mechanisms.

Q. ARE YOU AWARE OF ANY REPORTS OR INDUSTRY PUBLICATIONS THAT ADDRESS THE ISSUE OF HOW REGULATORY COMMISSIONS ARE ADDRESSING THE ISSUE OF REGULATORY LAG AND EARNINGS ATTRITION FOR ELECTRIC UTILITIES?

A. Yes, EEI published a report in April 2011 entitled "Innovative Regulation: A Survey of Remedies for Regulatory Lag." The report, which was prepared for EEI by Pacific Economics Group Research LLC, states:

> Many utilities are experiencing the problem of regulatory lag today. They are struggling with a tendency of costs to grow more rapidly than the delivery volumes and other billing determinants that cause revenue growth. Some utilities need major generation or transmission plant additions. Others are engaged in accelerated programs to modernize distribution plant or install advanced metering infrastructure ("AMI").

> Growth in the volume of utility service used by a typical customer ("average use") once helped to finance plant additions because it bolstered revenue more than cost. However, growth in average use has slowed with a weak economy and increased energy efficiency. Traditional approaches to regulation can fail to provide rate relief under these conditions. The result can be chronic financial attrition that increases risk and can discourage needed investment.[20]

Q. ARE THERE SPECIFIC EXAMPLES WHERE REGULATORY COMMISSIONS HAVE APPROVED INITIATIVES DESIGNED TO REDUCE REGULATORY LAG AND/OR MITIGATE EARNINGS ATTRITION?

A. Yes. As discussed earlier in my testimony, there are a variety of methods that regulators can use to reduce regulatory lag depending on the situation and the specific needs to be addressed.[21] These methods include: (1) the ability to earn a cash return on CWIP by including it in rate base; (2) the ability to establish rates based on a forecasted test year; (3) the approval of interim rates while a rate case is pending; (4) the approval of various regulatory adjustment mechanisms; (5) the use of formula rate plans or multi-year rate plans which adjust rates automatically each year without the need for a full rate case filing; and (6) revenue decoupling mechanisms to offset declining average use per customer. The following section of my testimony provides examples of each method, and how each contributes to a reduction in regulatory lag so that utilities have a better opportunity to earn their authorized ROE.

[20] Innovative Regulation: A Survey of Remedies for Regulatory Lag, Edison Electric Institute, prepared by Pacific Economics Group Research LLC, April 2011, at 1.

[21] As I earlier noted, I recognize that some of these mechanisms are not available to the Commission due to Missouri law, but, the point is that given those limitations, it is even more important that this Commission utilize the mechanisms it can.

Q. PLEASE DISCUSS HOW REGULATORY LAG HAS BEEN REDUCED THROUGH THE INCLUSION OF CWIP IN RATE BASE.

A. Regulatory lag is an important consideration for investors when a utility undertakes major capital construction projects, such as new generation or transmission facilities. By allowing utilities to place CWIP in rate base and by pre-approving certain levels of cost recovery, regulators have alleviated investor concerns about possible cost disallowances and pressure on cash flows during the construction phase, as well as mitigated ratepayer concerns about rate shock once the construction project is completed and the plant is placed in service.

States such as Florida, South Carolina and Georgia have addressed this concern through legislation that allows utilities to include construction costs in rate base for new nuclear generation plants before the facility is placed in service. Even before the legislation in Georgia was signed into law, the Georgia Public Service Commission approved the request by Georgia Power to include CWIP in rate base to recover the financing costs attributable to the construction of two nuclear plants through retail base rates. In approving the application, the Commission noted that including CWIP in rate base would protect Georgia Power's credit quality and financial integrity, and would ultimately benefit ratepayers. The Order states:

> The record contains ample evidence regarding the benefits of CWIP. First, Georgia Power presented evidence that its proposal for CWIP would reduce the cost of the plant \$300 million in nominal dollars. (Tr. 639-40). Granting the Company's request for CWIP also protects the Company's credit quality by minimizing the risk of a downgrade. (Tr. 640). A downgrade to the Company's credit rating would increase Georgia Power's financing costs, and these increased costs would ultimately be passed on to ratepayers. (Tr. 640). Based on this

> record, the Commission finds that the Company's CWIP proposal will benefit ratepayers.[22]

Similarly, the Colorado Public Utilities Commission approved a Stipulation and Settlement Agreement, in which the parties agreed that Public Service Company of Colorado ("PSCO") should be allowed to place CWIP in rate base without an AFUDC offset for generation and transmission expenditures. The CWIP was related to construction of PSCO's new 750 MW Comanche 3 coal-fired generation facility, which was projected to cost approximately $1.35 billion between 2006 and 2010.[23] In support of PSCO's request to include these capital expenditures in rate base, the Company's Chief Financial Officer explained:

> The additional capital expenditures we are spending at Public Service Company are perceived by the financial community very much like a double-edged sword. With the proper regulatory treatment it is viewed as a positive. If, on the other hand, the market perceives the Company is receiving a sub-optimal return, the additional investment will be perceived as a liability making it more difficult to attract capital.[24]

In assessing U.S. regulatory environments, S&P has commented on the importance of regulators' willingness to support capital projects as follows:

> Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible

[22] Georgia Public Service Commission, Docket No. 27800, Georgia Power's Application for the Certification of Units 3 and 4 at Plant Vogtle and Updated Integrated Resource Plan, Order on Remand, June 17, 2010, at 16-17.
[23] Colorado Public Utilities Commission, Docket No. 06S-234EG, Public Service Company of Colorado, Inc., Decision C06-1379, Order Approving Settlement Agreement with Modifications, December 1, 2006, at 20-21.
[24] Direct Testimony and Exhibits of Benjamin G.S. Fowke, III, Public Service Company of Colorado, Docket No. 06-0234EG, at 8.

> to construction delays. Allowance of a cash return on construction work in progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program.[25]

Q. HOW DO FORECASTED TEST YEARS HELP TO REDUCE REGULATORY LAG AND MITIGATE EARNINGS ATTRITION?

A. The ability to use a forecasted test year to establish base rates significantly increases the probability that a utility will have a reasonable opportunity to earn its authorized ROE because the projected revenues, expenses, and investments better reflect the circumstances during the period when rates will be in effect. As noted in the EEI report, the use of historical test years contributes to regulatory lag especially during periods when utility costs are increasing more rapidly than average customer usage or billing determinants.[26] The EEI report shows that 20 states now use a fully or partially forecasted test year to establish base rates for electric utilities.[27] Further, several states including New Mexico and Colorado recently have passed legislation that gives utilities the option to file rate case requests based on forecasted test years rather than historical test years.

The Wisconsin Public Service Commission is notable in its use of forecasted test years, a practice which has been in place for about 40 years. Regulated utilities in Wisconsin generally file a rate case every two years using a forecasted test year. This

[25] Assessing U.S. Utility Regulatory Environments, Standard and Poor's Global Credit Portal RatingsDirect, March 11, 2010, at 6.
[26] Innovative Regulation: A Survey of Remedies for Regulatory Lag, Edison Electric Institute, prepared by Pacific Economics Group Research LLC, April 2011, at 31.
[27] Ibid, Table 1, at 2-3.

practice alleviates concerns that the utility is not recovering operating or capital costs in a timely manner, and provides investors with assurance that the Commission has reviewed the companies' cost structure on a regular basis so that adverse regulatory outcomes are much less common. In its summary of the Wisconsin regulatory environment, SNL Financial notes:

> As has been the case for several years, Wisconsin regulation is constructive from an investor viewpoint. The utilities are regulated under a traditional framework, and the most recently authorized equity returns have approximated or been slightly above the national averages. The use of forecasted test periods and other constructive financial practices, such as adopting comparatively equity-rich capital structures and typically permitting a current, cash return on 50% of construction work in progress, have provided the state's utilities a reasonable opportunity to maintain solid credit quality metrics and to earn their authorized returns.[28]

Q. HOW HAVE INTERIM RATES BEEN USED TO REDUCE REGULATORY LAG AND EARNINGS ATTRITION?

A. The ability to implement interim rates while a rate case is pending provides a utility with more immediate cost recovery, especially when costs are higher or average customer usage/billing determinants are lower than during the test period used to establish current rates. Several jurisdictions (*e.g.*, Minnesota, North Dakota, and Iowa) routinely approve interim rate requests whenever a rate case is filed, subject to customer refund with interest if the ultimate rate increase approved by the Commission is lower than the interim rates. Many other jurisdictions have the ability to grant interim rates under certain circumstances when the utility demonstrates that

[28] Source: SNL Financial, Summary of State Commissions, accessed January 2012.

economic conditions or financial distress would inhibit its ability to attract capital or maintain its financial integrity or credit rating.

For example, the Minnesota Public Utilities Commission approved Interstate Power and Light's ("IPL") request to implement interim rates, subject to customer refund, if the ultimate approved revenue requirement was lower than the amount authorized in interim rates. In the order approving interim rates, the Minnesota Commission noted that Minnesota statutes require the Commission to order an interim rate schedule into effect within 60 days from the filing of a general rate case, unless the Commission allows the proposed rates to go into effect. The order further explained the principles that are used to establish interim rates:

> Interim rates are based on the proposed test year cost of capital, the proposed test year rate base, and the proposed test year expenses. They are calculated using existing rate design and the rate of return on common equity authorized in the Company's last rate case. Only rate base and expense items similar in nature and kind to those allowed under the company's last general rate order can be included in interim rate calculations.[29]

Moody's has commented on the benefit of interim rates in terms of reducing regulatory lag as follows:

> Because of the length of base rate cases, with many lasting 12 months and some as long as 18 months, interim rate relief is an effective way to accelerate rate relief, reduce regulatory lag, and maintain utility cash flow while rate cases are pending.[30]
>
> ***
>
> Other cost recovery related factors Moody's considers to be favorable to utility credit quality include granting of interim rate relief, which we view as an effective way to accelerate the lengthy and cumbersome

[29] Minnesota Public Utilities Commission, Docket No. E-001/GR-10-276, Interstate Power and Light, Order Setting Interim Rates, June 30, 2010, at 1-2.
[30] Cost Recovery Provisions Key to Investor Owned Utility Rating and Credit Quality, Evaluating a Utility's Ability Recover Costs and Earn Returns, Moody's Investors Service, June 18, 2010, at 10-11.

> rate case process, reduce regulatory lag, and maintain utility cash flow while rate cases are pending.[31]

The use by Missouri utilities of an historical test year suggests that there is a significant lag between the time when expenses have increased, new plant has been placed in service, and customer usage has declined and the time when new rates become effective. The fact that Missouri utilities have not thus far been allowed to routinely implement interim rates, due to the stringent threshold standards adopted by the MoPSC, contributes substantially to regulatory lag and chronic earnings attrition at utilities such as Ameren Missouri.

Q. HAVE CAPITAL TRACKING MECHANISMS BEEN USED TO REDUCE REGULATORY LAG AND EARNINGS ATTRITION?

A. Yes. Capital trackers have been used to recover costs for infrastructure replacement programs and to enhance system reliability, among other things. According to the EEI report on innovative ways to reduce regulatory lag, 24 jurisdictions have approved capital tracking mechanisms for electric utilities, while three additional jurisdictions (including Missouri) have approved capital trackers for gas utilities only.[32] For example, the Public Utility Commission of Texas recently adopted rules to implement Senate Bill 1693, which allows electric utilities in Texas to recover changes in distribution costs that occur between rate case proceedings through the Distribution Cost Recovery Factor ("DCRF"). In the Order adopting the new rules, the Texas Commission stated:

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[31] Ibid, at 2.

[32] Innovative Regulation: A Survey of Remedies for Regulatory Lag, Edison Electric Institute, prepared by Pacific Economics Group Research LLC, April 2011, Table 1, at 2-3.

> With respect to the general impact of a DCRF on an electric utility's financial condition, the commission observes that the opportunity for a DCRF application as often as once every calendar year clearly provides for reduced regulatory lag, which eliminates at least some degree of uncertainty with respect to the timing of an electric utility's recovery of investment. A reduction in regulatory lag during a period when an electric utility is increasing its investments positively impacts the electric utility's financial condition.[33]

Q. PLEASE DESCRIBE HOW THE IMPLEMENTATION OF OTHER REGULATORY MECHANISMS, ESPECIALLY COST TRACKING MECHANISMS AND RATE RIDERS, CAN REDUCE REGULATORY LAG AND EARNINGS ATTRITION.

A. Regulatory mechanisms, including cost tracking mechanisms and rate riders, generally are designed to support recovery of costs associated with expenses or capital costs that fluctuate significantly from period to period, as well as costs that are beyond the control of utility management, and costs that are difficult to predict with any degree of accuracy. For example, utilities in Illinois and Michigan have been authorized to implement riders for uncollectible accounts and bad debt expenses; utilities in Massachusetts have been allowed to use annual adjustment clauses for pension and post-retirement benefit expenses; and utilities in Mississippi have been granted approval for riders related to storm damage, while those in New Hampshire have been allowed to recover storm-related costs through a cost tracking mechanism that defers costs for future recovery.

[33] Public Utility Commission of Texas, Project No. 39465, September 15, 2011, at 146.

Q. PLEASE EXPLAIN HOW FORMULA RATE PLANS HAVE EFFECTIVELY REDUCED REGULATORY LAG AND PROVIDED UTILITIES WITH A BETTER OPPORTUNITY TO EARN THEIR AUTHORIZED ROE.

A. Formula rate plans generally allow utilities to adjust rates automatically every year without the need to file a time consuming and costly rate case. The plans include various components such as expense and rate base adjustments for inflation less a productivity factor, updated assumptions with regard to customer usage and billing determinants, changes to the authorized return based on financial market conditions, and earnings sharing mechanisms that allow the utility and its ratepayers to share some specified percentage of any over- or under-earning. Some formula rate plans, such as the one for Alabama Power, have been in effect for many years, while others have been adopted recently, such as new legislation in Illinois which allows electric utilities including Ameren Illinois to adjust rates annually using an ROE based on the yield on 30-year Treasury bonds plus a risk premium of approximately 5.80%.

Under terms of Alabama Power's formula rate plan, which was originally adopted in 1982 for the purpose of stabilizing rates, by each December 1, the Company's ROE is computed for the upcoming twelve-month period ending December 31. If the resulting ROE is less than 13.00% or more than 14.50%, then monthly bills are increased or decreased by amounts per kilowatt-hour necessary, in total, to restore the ROE to 13.75%. Consecutive increases are limited such that adjustments for any consecutive two-year period, when averaged together, do not exceed 4.00%. The maximum increase in any one year cannot exceed 5.00% of the projected total retail revenues of the Company for the rate year used to compute the ROE. If the

Company's actual retail ROE for the immediately preceding calendar year is above the equity return range, then the Company must refund to retail customers the amount of revenue that caused the actual retail return to exceed the top end of the designated range. There is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.[34]

SNL Financial ranks the Alabama regulatory environment as constructive, due in large part to the timely recovery of costs and investments through the formula rate plan. SNL notes:

> Alabama regulation, as it has been for many years, is constructive from an investor viewpoint, largely the result of formulary rate adjustment mechanisms that provide for the timely rate recognition of utility costs and investments and tend to de politicize the regulatory process. In addition, the equity return ranges included in these frameworks are well above the average equity returns that have been authorized energy utilities nationwide over the last several years.[35]

Q. HOW DO MULTI-YEAR RATE PLANS HELP TO REDUCE REGULATORY LAG?

A. Multi-year rate plans are similar to formula rate plans, in that both adjust rates annually based on updated information or assumptions with respect to revenues, expenses, and plant investment. Multi-year rate plans generally are in effect for three to five years, which provides some degree of earnings and cash flow certainty for investors and some degree of rate stability for ratepayers. Since rates are adjusted automatically each year during the rate plan, there is no delay between the time when a rate case is filed and the time when the Commission issues its decision. According

[34] Southern Company, Form 10-K for the fiscal year ended December 31, 2010, at II-74, and Alabama Power Rate Stabilization and Equalization Factor (tariff)

[35] Source: SNL Financial, State Commission Summaries, accessed January 2012.

to the EEI report, multi-year rate plans are currently used in eight jurisdictions, including New York, California and Massachusetts.[36] In addition to reducing regulatory lag, these multi-year rate plans have been effective in terms of achieving regulatory efficiency by reducing the frequency of rate case filings, while allowing the utilities to adjust their rates based on projected changes in expenses and rate base. The New York Public Service Commission noted the benefit of multi-year rate plans in terms of reducing the number of rate filings, as follows:

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing—the third in three years—ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[37]

Such an approach could be particularly useful in Missouri, where the Commission has been faced with the second highest number of rate case filings (*i.e.*, 16) of any jurisdiction in the past three years.[38] Only Wisconsin has received more rate filings in that period, and, as noted earlier in my testimony, utilities in Wisconsin generally file a rate case every two years.

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[36] Innovative Regulation: A Survey of Remedies for Regulatory Lag, Edison Electric Institute, prepared by Pacific Economics Group Research LLC, April 2011, Table 1, at 2-3.
[37] New York Public Service Commission, Order 08-E-0539, April 24, 2009, at 282.
[38] Source: SNL Financial, State Commission Summaries, accessed January 2012.

Q. PLEASE DESCRIBE HOW REVENUE DECOUPLING MECHANISMS HAVE HELPED MITIGATE REGULATORY LAG OR EARNINGS ATTRITION.

A. Revenue decoupling mechanisms have been adopted by regulatory commissions for electric utilities, especially in jurisdictions with more aggressive demand-side management ("DSM") and energy efficiency programs that have resulted in declining average use per customer. As average use per customer declines, the utility does not fully recover that portion of fixed costs that is recovered through variable rates. Decoupling mechanisms sever the link between revenues and customer usage, and remove the disincentive for utilities to promote energy efficiency and DSM programs. In that way, revenue decoupling mechanisms stabilize revenues and cash flows from year to year, which enhances the ability of the utility to earn its authorized ROE.

Revenue decoupling has become increasingly prevalent in the industry. In Massachusetts, for example, all regulated utilities are required to file revenue decoupling mechanisms by no later than 2012. New York and California also have approved revenue decoupling mechanisms in recognition of the trend toward declining average use per customer that is prevalent among both electric and natural gas utilities in those states.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING INITIATIVES THAT HAVE BEEN ADOPTED IN OTHER JURISDICTIONS TO REDUCE REGULATORY LAG AND MITIGATE EARNINGS ATTRITION?

A. My primary conclusion is that regulatory commissions can reduce regulatory lag and earnings attrition through the effective use of the different options described above.

More importantly, reducing regulatory lag not only provides the utility with an improved opportunity to earn its authorized return, but it also benefits customers through a financially sound utility that can make the necessary investments to continue to provide safe and reliable electric utility service, and potentially through a higher credit rating that would allow the utility to issue debt at more favorable interest rates.

Q. IF THE COMMISSION DOES NOT TAKE STEPS TO MITIGATE EARNINGS ATTRITION, WHAT IS THE PROBABLE EFFECT ON THE COMPANY?

A. If the Commission authorizes a competitive ROE but then allows it to be eroded by regulatory lag, Ameren Corporation is placed at a distinct disadvantage in raising capital compared to companies with commensurate risk who do have a reasonable opportunity to earn their authorized returns. This directly impacts Ameren Missouri and its customers through higher capital costs, less internally generated cash to fund operations, and less investment. This is especially problematic given the earnings attrition Ameren Missouri is already experiencing in its normal operations where costs are increasing while sales are declining, and rates created during the historical test year will be inadequate to provide for both cost recovery and the opportunity to earn the allowed ROE. Satisfying long-term energy policy objectives, investing in non-revenue producing energy infrastructure, and meeting the increasing expectations of customers all suffer. This is not sustainable and must be addressed.

Further, as mentioned previously, the Illinois legislature recently passed "formula rate plan" legislation. Absent the Missouri Commission addressing the issues of timely cost recovery and a fair opportunity for Ameren Missouri to earn its allowed ROE, the Illinois legislation will have the effect of making Ameren Illinois a significantly better investment for Ameren Corporation than Ameren Missouri.

Q. WILL ADOPTION OF THE MECHANISMS PROPOSED BY AMEREN MISSOURI IN THIS CASE ELIMINATE THE ISSUE OF REGULATORY LAG IN MISSOURI?

A. They will not completely solve the issue. But even if they cannot entirely solve the issue, they can improve it. They can give the Company a more reasonable opportunity to earn a fair return; they can encourage the Company to invest in its system instead of deferring beneficial investment; they can improve Ameren Corporation's ability to provide investment capital needed to make those investments; and they can improve credit metrics and help make investment capital more available at lower costs.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I recommend that the Commission continue the Company's existing FAC and trackers, and approve the Company's proposed Plant-In-Service Accounting and two-way storm restoration cost tracker. Though a compensatory allowed ROE, as proposed by witness Hevert, is important, Ameren Missouri must also have the opportunity to earn that return. The Plant-In-Service Accounting treatment and storm cost tracker will provide Ameren Missouri with a more reasonable opportunity to recover its expenses and earn its authorized ROE, maintain its operating practices and make necessary non-revenue producing investments in infrastructure, and benefit the Company's customers with the level of safe and reliable electric service they expect.

Q. IS THIS SIMPLY AN EFFORT ON BEHALF OF AMEREN MISSOURI TO INCREASE RATES?

A. No. Ameren Missouri's rates are among the lowest in the country and are, in fact, the lowest in Missouri. As I have previously discussed, the Company must compete for funds to sustain operations. Given the returns that Ameren Missouri has historically earned, the cost to obtain those funds will be higher than those of other utilities that earn closer to their authorized return.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a	)	
Ameren Missouri's Tariffs to Increase Its Revenues	)	**Case No. ER-2012-0166**
for Electric Service.	)	

AFFIDAVIT OF JOHN REED

STATE OF MASSACHUSETTS)
) ss
CITY OF MARLBOROUGH)

John Reed, being first duly sworn on his oath, states:

1. My name is John Reed and my office is located in Marlborough, Massachusetts and I am Chairman and Chief Executive Officer with Concentric Energy Advisors, Inc.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 49 pages and Schedules JJR-1 through JJR-3, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

John Reed

Subscribed and sworn to before me this 1st day of February, 2012.

Joanne P. Bickford
Notary Public

My commission expires: 10/15/15

JOANNE P. BICKFORD
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
MY COMMISSION EXPIRES
OCTOBER 15, 2015

JOANNE P. BICKFORD
NOTARY PUBLIC

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 30 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	11/87, 2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91, 11/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline
Southern Connecticut Gas	5/06	Southern Connecticut Gas	Docket No. 05-03-17PH01	LNG/Trunkline
Southern Connecticut Gas	8/08	Southern Connecticut Gas	Docket No. 06-05-04	Peaking Service Agreement
District Of Columbia PSC				
Potomac Electric Power Company	3/99, 5/99, 7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87, 5/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	7/93, 8/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94, 3/95	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates; rate design
Tennessee GSR Group	1/95, 3/95, 1/96	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
PG&E and SoCal Gas	8/96, 9/96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04 2/05	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	
Portland Natural Gas Transmission System	6/08	Portland Natural Gas Transmission System	Docket No. RP08-306-000	Market Assessment, natural gas transportation; rate setting
Portland Natural Gas Transmission System	5/10, 3/11, 4/11	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Business risks; extraordinary and non-recurring events pertaining to discretionary revenues
Morris Energy	7/10	Morris Energy	Docket No. RP10-	Affidavit re: Impact of Preferential Rate
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 070650-EI	Need for new nuclear plant
Florida Power and Light Co.	5/08	Florida Power & Light Co.	Docket No. 080009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/09	Florida Power & Light Co.	Docket No. 080677-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/09, 5/09, 8/09	Florida Power & Light Co.	Docket No. 090009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/10; 5/10, 8/10	Florida Power & Light Co.	Docket No. 100009-EI	New Nuclear cost recovery, prudence

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Florida Power and Light Co.	3/11, 7/11	Florida Power & Light Co.	Docket No. 110009-EI	New Nuclear cost recovery, prudence
Florida Senate Committee on Communication, Energy and Utilities				
Florida Power and Light Co.	2/09	Florida Power & Light Co.		Securitization
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08, 03/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Northern Indiana Public Service Company	08/08	Northern Indiana Public Service Company	Cause No. 43526	Fair Market Value Assessment
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Municipalization
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Municipalization
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Municipalization
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Municipalization
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Municipalization
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy Consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Integrated Resource Management
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Merge approval
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling, risk
NStar	6/11	NStar, Northeast Utilities	DPU 10-170	Merger approval
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06, 1/07	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
WE Energies	12/11	Wisconsin Electric Power Co.	Case No. U-16830	Economic Benefits/Prudence
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	PPA, Financial Impacts
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity
Northern States Power	11/08, 05/09	Northern States Power Company	Docket No. E002/GR-08-1065	Return on Equity
Northern States Power	11/09 6/10	Northern States Power Company	Docket No. G002/GR-09-1153	Return on Equity
Northern States Power	11/10, 5/11	Northern States Power Company	Docket No. E002/GR-10-971	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Missouri Gas Energy	11/10, 1/11	KCP&L	Case No. ER-2010-0355	Natural Gas DSM
Missouri Gas Energy	11/10, 1/11	KCP&L GMO	Case No. ER-2010-0356	Natural Gas DSM
Laclede Gas Company	5/11	Laclede Gas Company	Case No. CG-2011-0098	Affiliate Pricing Standards
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH-1-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Toll Design
Brunswick Pipeline	5/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	3/07, 04/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	Toll Design
Repsol Energy Canada Ltd	3/08	Repsol Energy Canada Ltd	GH-1-2008	Market Study
Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory policy, toll development

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Enbridge Gas New Brunswick	MCTN #298600	Rate Setting for EGNB
Atlantic Wallboard/Flakeboard	09/09, 6/10, 7/10	Enbridge Gas New Brunswick	NBEUB 2009-017	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
Morris Energy Group	11/09	Public Service Electric & Gas	BPU GR 09050422	Discriminatory Rates
New Jersey American Water Co.	4/10	New Jersey American Water Co.	BPU WR 1040260	Tariff Rates and Revisions
Electric Customer Group	01/11	Generic Stakeholder Proceeding	BPU GR10100761 and ER10100762	Natural gas ratemaking standards and pricing
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70, Approval of New Facilities
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Rochester Gas and Electric and NY State Electric & Gas Corp	2/10	Rochester Gas & Electric NY State Electric & Gas Corp	Case No. 09-E-0715 Case No. 09-E-0716 Case No. 09-E-0717 Case No. 09-E-0718	Depreciation policy
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Storage issues
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Oklahoma Gas & Electric Company	03/08	Oklahoma Gas & Electric Company	Cause No. PUD 200800086	Acquisition of Redbud generating facility
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Rate Design, unbundling
ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Design, unbundling

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices, Prudence
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Oncor Electric Delivery Company	6/08	Oncor Electric Delivery Company	Docket No.35717	Regulatory policy
Oncor Electric Delivery Company	10/08, 11/08	Oncor, TCC, TNC, ETT, LCRA TSC, Sharyland, STEC, TNMP	Docket No. 35665	Competitive Renewable Energy Zone
CenterPoint Energy	6/10 10/10	CenterPoint Energy/Houston Electric	Docket No. 38339	Regulatory policy, risk, consolidated taxes
Oncor Electric Delivery Company	1/11	Oncor Electric Delivery Company	Docket No. 38929	Regulatory policy, risk
Texas Railroad Commission				
Western Gas Interstate Company	1/85	Southern Union Gas Company	Docket 5238	Cost of Service
Atmos Pipeline Texas	9/10; 1/11	Atmos Pipeline Texas	GUD 10000	Ratemaking Policy, risk
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Benchmarking in support of ROE
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Cost of Service
Green Mountain Power	7/98, 9/00	Green Mountain Power	Docket No. 6107	Rate development
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant
Wisconsin Electric Power Company	10/09	Wisconsin Electric Power Co.	Docket No. 6630-CE-302	CPCN Application for wind project

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern		Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Nevada Power Company	4/08	Nevada Power v. Nevada Cogeneration Assoc. #2		Power Purchase Agreement
Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC	1/11	Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC v. Pepco Energy Services	Case No. 11-198-Y-00848-10	Change in usage dispute/damages
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07, 10/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
State of New York, Nassau County Supreme Court				
Steel Los III, LP	6/08	Steel Los II, LP & Associated Brook, Corp v. Power Authority of State of NY	Index No. 5662/05	Property seizure
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service
State of Texas District Court of Nueces County				
Northwestern National Insurance Company	11/11	ASARCO LLC	No. 01-2680-D	Damages

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, No. District of New York				
Cayuga Energy, NYSEG Solutions, The Energy Network	09/09	Cayuga Energy, NYSEG Solutions, The Energy Network	Case No. 06-60073-6-sdg	Going concern
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06, 11/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing, tax dispute
Consolidated Edison Company	2/08, 6/08	Consolidated Edison Company v. United States	No. 04-0033C	SNF Expert Report

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Vermont Yankee Nuclear Power Corporation	6/08	Vermont Yankee Nuclear Power Corporation	No. 03-2663C	SNF Expert Report
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99, 8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Electric restructuring, environmental impacts
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05, 2/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
Council of the District of Columbia Committee on Consumer and Regulatory Affairs				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

Table 1

Innovations to Reduce Regulatory Lag: An Overview of Current Precedents

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Multiyear Revenue Cap[3]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
					Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Alabama								Yes	Yes
Arizona									
Arkansas	Yes				Yes (gas only)				
California	Yes		Yes (electric only)	Yes	Yes				Yes
Colorado	Yes (electric only)	Yes			Yes (gas only)	Yes (electric only)			Pending
Connecticut					Yes (electric only)	Yes (gas only)	Yes (electric only)		Yes
Delaware							Pending		
District of Columbia					Yes (electric only)				
Florida	Yes (electric only)	Yes					Yes (gas only)		Yes
Georgia	Yes	Yes	Yes (electric only)				Yes (gas only)		Yes
Hawaii	Yes (electric only)			Yes (electric only)	Yes (electric only)				Yes
Idaho					Yes (electric only)				
Illinois	Yes (gas only)				Yes (gas only)		Yes (gas only)		Yes
Indiana	Yes	Yes			Yes (gas only)	Yes (electric only)			
Iowa	Yes (electric only)								
Kansas	Yes	Pending							
Kentucky	Yes					Yes			Yes
Louisiana	Yes (electric only)	Yes						Yes	
Maine	Yes (electric only)		Yes						Yes
Maryland		Yes			Yes				
Massachusetts	Yes		Yes		Yes	Yes			
Michigan		Pending			Yes				Yes

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Multiyear Revenue Cap[3]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
					Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Minnesota	Yes (electric only)	Yes			Yes (gas only)				Yes
Mississippi	Yes (electric only)	Yes					Yes (electric only)	Yes	Yes
Missouri	Yes (gas only)						Yes (gas only)		
Montana					Yes (electric only)				
Nebraska									
Nevada					Yes (gas only)	Yes (electric only)			
New Hampshire									
New Jersey	Yes				Yes (gas only)				
New Mexico		Pending							Pending
New York	Yes			Yes	Yes				Yes
North Carolina		Yes			Yes (gas only)	Yes (electric only)			
North Dakota		Pending					Yes (gas only)		Yes
Ohio	Yes		Yes (electric only)			Yes (electric only)	Yes (gas only)		
Oklahoma	Yes (electric only)	Pending				Yes (electric only)	Yes (gas only)	Yes (gas only)	
Oregon	Yes				Yes	Yes (gas only)			Yes
Pennsylvania	Yes (electric only)								
Rhode Island					Pending				Yes
South Carolina		Yes				Yes (electric only)		Yes (gas only)	
South Dakota		Pending							
Tennessee					Yes (gas only)				Yes
Texas	Yes (electric only)	Yes						Yes (gas only)	
Utah	Yes (gas only)				Yes (gas only)				Yes
Vermont	Yes (electric only)			Yes	Yes				
Virginia	Yes (electric only)	Yes			Yes (gas only)				
Washington					Yes (gas only)				
West Virginia		Yes							
Wisconsin		Yes			Yes				Yes
Wyoming					Yes (gas only)	Yes (electric only)			Yes (electric only)

[1] This column pertains only to electric utilities.

[2] This column excludes plans involving rate freezes.

[3] Revenue caps are also denoted as decoupling true up plans. However, many decoupling true up plans do not involve multiyear revenue caps because they do not have broad-based revenue adjustment mechanisms.