FILED
DECEMBER 22, 2016
INDIANA UTILITY
REGULATORY COMMISSION

44893

VERIFIED DIRECT TESTIMONY

OF

JOHN J. REED

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

<u>SPONSORING IPL WITNESS JJR ATTACHMENTS 1 THROUGH 2</u>

VERIFIED DIRECT TESTIMONY OF JOHN J. REED
ON BEHALF OF
INDIANAPOLIS POWER & LIGHT COMPANY

I. INTRODUCTION AND BACKGROUND

Q1. Please state your name and business address.

A1. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q2. By whom are you employed and in what capacity?

A2. I am the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. and CE Capital Advisors, Inc. (together "Concentric").

Q3. What is your background and experience in the energy and utility industries?

A3. I have more than 35 years of experience in the energy and utility industries, and have worked as an executive in, and consultant and economist to, the energy and utility industries. Over the past 26 years, I have directed the energy consulting 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 Federal Energy Regulatory Commission, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. My experience is described in more detail in IPL Witness JJR Attachment 1.

Q4. Please describe Concentric's activities in energy and utility engagements.

A4. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory economic and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, corporate and business unit strategy development, demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy and sell-side merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America. CE Capital Advisors, Inc. is a fully registered broker-dealer securities firm specializing in merger and acquisition activities. As CEO of CE Capital Advisors, Inc., I hold several securities licenses that cover all forms of securities and investment banking activities.

II. PURPOSE OF TESTIMONY AND CONCLUSION

Q5. What is the purpose of your testimony?

A5. I have been asked by Indianapolis Power & Light Company ("IPL") to address two topics in my testimony: first, the policy implications of rate recovery for new plant additions and second the valuation of the electric generating facilities that were in service as of June 30, 2016.

Q6. Please summarize your testimony with respect to the policy implications of rate recovery for new plant additions.

A6. My testimony contrasts the opportunities that utilities had to recover the costs of new capital additions in the more robust electric markets that existed prior to 2000 with the opportunity for cost recovery that exists today. In particular, I discuss how movement from an environment of system expansion and increasing customer usage to a more mature system, with limited expansion potential, conservation and declining customer usage can affect a company's ability to recover its investments. This issue is critical for most major electric utilities in the country, the majority of which are faced with the requirement for large capital investments for system improvements and modernizations that are not revenue generating. In addition, I provide some examples of how other jurisdictions are addressing capital additions outside of general rate proceedings. My conclusion on this issue is that now, more than ever before, as utilities are faced with significant infrastructure improvements, ratemaking decisions that provide a real opportunity for the utility to recover through rates a return of and on the costs of these improvements is critical for the financial stability of the utilities.

Q7. How did you conduct the valuation of the generating assets?

A7. In conducting this analysis, I relied on an income approach, specifically the discounted cash flow methodology ("DCF Approach" or "DCF"), which is most commonly relied on by market participants valuing operating generation assets. The purpose of my testimony is to discuss the assumptions I relied on to develop the DCF of IPL's electric generation assets and the resulting Current Value of the production assets.

Q8. What generation assets did you value using the DCF Approach?

A8. The assets that I included in the analysis are summarized in Table 1below and are further discussed by IPL Witness Bradley Scott. These assets are referred to in the remainder of my testimony collectively as "the IPL Generation Assets". Notably, my analysis does not include the combined cycle gas turbine ("CCGT") at Eagle Valley that is under construction at the time of my analysis and scheduled to be placed in service on approximately April 30, 2017.

Table 1: IPL Generation Assets[1]

Plant	Unit	Capacity (MW)	Fuel
Harding Street	5	100.0	Natural gas
Harding Street	6	98.0	Natural gas
Harding Street	7	420.0	Natural gas
Harding GT	4	73.1	Natural gas
Harding GT	5	75.4	Natural gas
Harding GT	6	145.6	Natural gas
Petersburg	1	222.0	Coal
Petersburg	2	410.0	Coal
Petersburg	3	520.0	Coal
Petersburg	4	520.0	Coal
Georgetown	1	74.3	Natural gas
Georgetown	4	75.3	Natural gas
Total		2,733	

Q9. What conclusion did you reach regarding the value of IPL's Generation Assets using the DCF Approach?

A9. In my opinion, the Current Value of the IPL Generation Assets based on the DCF Approach is $931.3 million.

[1] The capacity shown in Table 1 is the normal operating generating capacity of the plants based on the 2016 Organization of MISO States ("OMS") Survey. These values differ slightly from the planning capacity which is presented in IPL Witness Scott's Schedule 1 but are appropriate to be used for valuation purposes. Harding Street, and Petersburg also have diesel or oil generation on site. These small generators, which are generally available for black start capability, were considered part of the larger facility and were not valued separately.

III. <u>REGULATORY TREATMENT OF CAPITAL INVESTMENT</u>

Q10. How have utilities traditionally recovered the costs of capital investments?

A10. As utilities' service territories were being developed, capital investment was closely linked to the expansion of the service territory, increasing the number of customers served and expanding the usage per customer. In these growth oriented markets, the used and useful capital investment was included in rate base through full blown general rate cases and in that way rates were designed and implemented to provide the utility a return on and of the investments in the system. Customer growth and increases in usage following the general rate case helped to offset post rate case cost increases and otherwise supported the utility's opportunity to earn the return "of" and "on" its investment necessary to maintain both the financial viability of the utility and investor confidence in the utility and the ratemaking framework.

Q11. How does the capital investment today differ from the scenario you just described?

A11. Electric utilities are mature businesses with a high market saturation. Therefore, the capital investment today is often not expanding the reach of the utility transmission and distribution system, nor is it connecting significant numbers of new customers. The demands on our utilities to maintain reliability and service quality, replace aging infrastructure and to invest in the environmental enhancements required to meet our public policy objectives in the face of declining use have created significant regulatory challenges. While these investments are critical to maintaining system integrity, safety, and service quality, they do not generate incremental revenue. Unlike investments in prior decades, the return "of" and "on" incremental investments and the associated costs are not supported by revenues stemming from customer/service area growth and usage increases. Further compounding this cost recovery risk is that customer usage is declining, as the efficiency of appliances increases and customer premises become more energy efficient. The effect of higher capital spending and lower customer usage is an increase in the overall cost to serve a customer base that is “mature” (*i.e.* slow-growing) as compared to the expanding customer base and related growth noted above.

Q12. What has been the traditional method for cost recovery of plant-related capital under the cost of service ratemaking model?

A12. Traditionally, the costs associated with new plant investment are capitalized as Construction Work in Progress (“CWIP”) along with the associated allowed debt and equity financing costs: Allowance for Funds Used During Construction (“AFUDC”). Costs accumulate in the CWIP account but are not incorporated into gross plant or rate base until the project is placed in service and deemed to be used and useful. At that point, the utility discontinues the accrual of AFUDC and commences recording depreciation expense on the new plant in service. The delay in recovery of those costs through the ratemaking process (often for several years) was less of a problem for a utility where ongoing investments were relatively small (compared to investment levels during the construction of power plants), and the utility could offset its unrecovered cash outlays with revenue increases associated with customer load growth. However, without the benefit of customer load growth, the accumulation of invested capital for the newly-constructed plant and other investments places a significant strain on utility cash flows and credit metrics prior to placing the assets in service. Further, the sudden addition of this substantial accumulation of costs to rate base once the plant is placed in service can lead to sharp increases in customer rates.

Q13. Have the credit rating agencies weighed in on the importance of cost recovery for significant capital expenditure ("CapEx") programs?

A13. Yes, they have. This is among the most important considerations for evaluating a utility's credit profile. Specifically, Moody's states, "[A] utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings."[2] Moody's specifically identifies the importance of cost recovery mechanisms for major capital expenditures and their importance in supporting credit quality and reducing regulatory lag:

> Regulatory pre-approval of major capital expenditures, especially for large, complex projects like new nuclear plants, are also important in the maintenance of utility credit quality. Similarly, the inclusion of CWIP in rate base provides greater regulatory certainty, reduces the chance of rate shock or regulatory disallowance at the end of the construction period, and helps moderate financial pressure on a utility during a capital build cycle. Some of these concepts require a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service.[3]

In its rating methodology, Moody's applies 25 percent weighting to the regulatory framework, which includes the legislative and judicial underpinnings of regulation and the consistency and predictability of regulation, and an additional 25 percent weighting to the ability to recover costs and earn returns, thereby equally weighing the timeliness of recovery of operating and capital costs and the sufficiency of rates and returns.[4]

---

2 Moody's Investors Service, Special Comment, *Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, Evaluating a Utility's Ability to Recover Costs and Earn Returns* (June 18, 2010), at 1.

3 *Id.*, at 2.

4 Moody's Investor Service, Rating Methodology, Regulated Electric and Gas Utilities, December 23, 2013, at 6.

Q14. Is there evidence that delayed or disallowed cost recovery has led to the degradation of utility credit quality?

A14. Yes. As Moody's chronicles in its Report on cost recovery mechanisms, 5 of 7 utility defaults over the past 50 years have been the result of insufficient or delayed rate relief for the recovery of costs or capital investments.[5] Moody's notes that the regulators' reluctance to provide rate relief in some cases reflected regulators' concerns about the impact of large rate increases on customers as well as concerns over prudence. Moody's stated that given the industry's sizable capital investment requirement to maintain its infrastructure and ensure environmental compliance there will be a heightened need for rate relief for utilities. Moody's has recognized however that the recovery requirement of the utility must also be balanced with the customers' ability to absorb the charges.[6]

Q15. What factors does Moody's consider when assessing the level of cost recovery provided by a regulatory authority?

A15. Moody's considers the following provisions in assessing the cost recovery mechanisms for a jurisdiction:

> Cost recovery provisions and a utility's ability to earn an adequate return are important considerations in determining credit quality and credit ratings in the regulated utility sector, so much so that they account for a significant 25% weighting when determining utility credit ratings under our Rating Methodology. Among the provisions we consider when judging this factor include a utility's ability to earn its allowed return on equity, which must be examined in conjunction with its actual earned return on equity resulting from its overall cost recovery provisions. These provisions could include automatic adjustment clauses, the use of a forward test year, regulatory pre-approval of major capital expenditures,

---

5 Moody's Investors Service, Special Comment, *Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, Evaluating a Utility's Ability to Recover Costs and Earn Returns* (June 18, 2010), at 3.

6 *Id*.

> construction work in progress (CWIP) in rate base, interim rate relief, decoupling, and the option of issuing cost recovery or securitized bonds to recovery [sic] large or unexpected costs. The presence of most or all of these provisions is likely to lead to a higher score for the cost recovery and earned return factor in our ratings methodology.[7]

In my view, Moody's would regard Indiana's practice of regulatory pre-approval and sometimes allowing for recovery of a cash return on CWIP through its use of adjustment mechanisms as relatively strong in promoting credit quality, providing that such recovery was not contentious, subject to unreasonable prudence challenges, or unnecessarily delayed in subsequent regulatory proceedings.

Q16. How have U.S. regulatory agencies addressed the challenges associated with significant capital expenditure requirements and mitigating the impact on customer rates?

A16. Many regulators have responded to these challenges with innovative mechanisms and frameworks geared towards preserving the utility's credit worthiness and mitigating rate shock by allowing the utility to recover a return on invested capital outside of a full rate case and/or before the plant is placed in service. Each regulatory solution is tailored to the utility and its specific circumstances, but they are generally designed to accomplish two things: 1) fund necessary long lead CapEx; and 2) allow up front determinations of prudence, so there is less uncertainty about the recovery of the investments.

---

7 *Id* at 13. *See also*, Moody's Investor Service, Rating Methodology, Regulated Electric and Gas Utilities, December 23, 2013, Factor/Sub-Factor Weighting- Regulated Utilities, at 6.

Cost recovery mechanisms that are commonly used include:

- Capital trackers – mimic rate case recovery but expedite recovery outside of a normal rate case. These trackers provide for investment cost, accumulating depreciation, returns on invested capital, and property taxes.
- CWIP in rate base – construction work in progress is added to rate base as it is incurred so it earns a return in rates immediately and would not be recovered using an AFUDC charge.
- Forward test years and multi-year rate plans– allow the utility to include forecasted capital investment in its test years and accordingly receive recovery through base rates, sometimes using stepped rates over a period of years.
- Decoupling mechanisms- establish a revenue requirement that does not fluctuate with actual usage.

These regulatory mechanisms can provide financial support to the utility to execute on its capital investment programs by stabilizing revenue, expediting cost recovery, neutralizing the effects of regulatory lag and preventing a deterioration in a utility's credit metrics. This is accomplished by establishing a fixed revenue requirement, allowing the utility to earn a return on its invested capital before the asset is placed in service, (allowing a return on and of the new investment without a general rate case), or by establishing stepped rates that anticipate the need for cost recovery and pre-approve rate increases tied to the future in-service dates or both. Further, these mechanisms may eliminate the need to "pancake" rate cases and lessen the eventual rate impacts on customers. As discussed below, and also discussed by IPL Witness McKenzie, there are significant differences between the above ratemaking framework and that which applies to IPL's capital investment.

Q17. What are the differences between capitalizing AFUDC in rate base versus allowing CWIP in rate base?

A17. Traditionally, regulators have allowed the financing costs associated with new plant construction to be capitalized as a regulatory asset known as AFUDC. The amounts allowed are determined through a regulatory review process, and are intended to mimic the actual financing costs that will be incurred in construction. AFUDC is capitalized and accumulated as part of the cost of the plant. This capitalized AFUDC earns a return that is also capitalized, thereby compounding the AFUDC costs in the total project costs. Once the plant is completed and placed in service, the accumulated AFUDC is added to rate base along with the costs of the completed project. The amount of AFUDC that is capitalized as part of the project in rate base can be significant given the financial magnitude and duration of the construction project, which can exacerbate the rate impact once the project is placed in service and rolled into rates. One approach to mitigating that rate impact is allowing CWIP into rate base, providing a cash return on the project as it is being constructed, so it is not necessary to capitalize and compound AFUDC. Adding CWIP to rate base effectively reduces the final capitalized cost of the project and "phases in" rate increases for the project over time, thereby mitigating potential rate shock.

Q18. How are tracking mechanisms typically implemented for significant capital projects?

A18. Capital trackers typically mimic rate base treatment for significant capital investments. The capital tracker isolates the costs of the investment, calculates the associated return on the addition to rate base, and rolls the incremental revenue requirement into rates through an adjustment mechanism or rider. In some cases, these mechanisms have been established for a development period as long as 5 to 10 years and can comprise a significant percentage of rate base that relates to new capital investments. These rate adjustment mechanisms are essential in that they allow the utility continuous access to funding for projects that would otherwise be beyond its ability to fund through current cash flows.

Q19. How do forward test years and multi-year rate plans provide for the ability to earn a return on and recovery of significant capital projects?

A19. Multi-year rate plans and forecast test years are both means of incorporating projected future CapEx in rates in the year they are budgeted to occur. The capital budget projections form the basis for rate adjustments from one year to the next. Similarly, multi-year rate plans often incorporate projected test years and provide some flexibility to phase in major plant additions in a stair-step pattern. Many multi-year rate plans are accompanied by capital trackers that allow the inclusion of capital additions outside the base rate calculation, as an incremental adjustment to rates.

Q20. How prevalent are alternative cost recovery mechanisms among investor-owned electric utilities?

A20. According to a 2015 EEI Survey of alternative regulatory mechanisms, some form of capital trackers are in use in all but 3 regulatory jurisdictions. These capital tracking mechanisms are predominantly used for generation, renewable investment, infrastructure replacement, smart grid investments, environmental compliance, reliability, and safety investments. The same report shows that forward test years are in effect in nearly half of the U.S. regulatory jurisdictions and multi-year rate plans are in effect in approximately

16 U.S. jurisdictions.[8] Finally, Regulatory Research Associates reports that 23 states have enacted laws or adopted rules allowing for the inclusion of at least some CWIP in rate base.

Q21. Please provide some examples where ratemaking mechanisms and processes support funding of significant capital projects.

A21. There are many, but I will highlight a few. South Carolina provides a good example with the passage of the Base Load Review Act ("BLRA") which effectively constitutes pre-approval of a utility's decision to construct a baseload power plant and deems the plant used and useful and prudent, providing recovery as long as the project proceeds in accordance with its budget and construction schedule. One year after filing for the BLRA Order, the utility may request to revise rates and earn a cash return on CWIP. In Virginia, riders are approved for recovery of investment in certain types of generation facilities, including a cash return on CWIP, and incentive ROE adders are awarded for new-nuclear and clean coal or carbon capture facilities. In Colorado, the PUC has allowed utilities to earn a cash return on CWIP for new generation facilities on a plant-specific basis. This is also the case in Florida where utilities may be authorized a cash return on CWIP for any new nuclear or integrated gasification combined cycle facilities and for upgrades to existing facilities that increase capacity. In Kentucky, the electric utilities have been allowed to include virtually all CWIP in rate base and earn a cash return. Generally, those states that allow CWIP in rate base do so as part of a general rate

[8] EEI, Alternative Regulation for Emerging Utility Challenges: 2015 Update (November 11, 2015).

case; but, in some states, such as South Carolina or Florida, the commission would allow the cash return on CWIP to occur through a rider or adjustment mechanism.[9]

Q22. To what extent are these mechanisms available to the utilities in IPL Witness McKenzie's cost of capital proxy group?

A22. As Mr. McKenzie states in his testimony, the rate adjustment mechanisms in place for IPL are more limited than those approved for the specific operating companies associated with the cost of capital proxy group.

Q23. What is the importance of prompt regulatory recovery to IPL?

A23. Prompt recovery is critical to the financial integrity of IPL. Investors, utility management and credit rating agencies need assurance that the utility will have a reasonable opportunity to earn a return "of" and "on" its capital projects, particularly those that are not eligible for timely cost recovery via a rate adjustment mechanism but must wait until the completion of construction and the implementation of new rates following the completion of a full general rate case. Without that assurance, IPL's ability to attract capital on reasonable terms going forward may be impaired.

Q24. How are IPL's capital investments recognized in the ratemaking process in Indiana?

A24. Much of the investment IPL has made for environmental compliance has been reviewed and pre-approved by the Commission pursuant to a statutory pre-approval process that also provides for timely cost recovery of all or most (80 percent) of the pre-approved cost through a rate adjustment mechanism including a return on CWIP and recovery of O&M

[9] RRA, Regulatory Focus, RRA Topical Special Report, Construction Work in Progress – Getting reacquainted with an old issue – (April 22, 2013).

costs once the project is placed in service.[10] Where timely cost recovery is limited to 80 percent, the remaining costs are deferred for ratemaking recognition in a general rate case.[11]

IPL's Eagle Valley CCGT and the Harding Street Units 5 & 6 Refueling Projects were pre-approved by the Commission , but there is no timely cost recovery via a rate adjustment mechanism for this investment.[12] The Commission authorized IPL to continue to accrue AFUDC and to defer depreciation expense following the commercial operation of these projects and until such costs are reflected in the ratemaking process. The investment cannot be reflected in rates until the property is placed in service and IPL implements new rates following the conduct of a rate case that recognize these costs. IPL's ability to earn a return "on" and "of" its new generation investment depends on the decision in the rate case and on post rate case circumstances which are largely outside the control of the utility, such as economic conditions and weather.

IPL's Harding Street Unit 7 Refueling was pre-approved and allowed to receive 80 percent timely cost recovery with the remaining cost deferred to a general rate case. A regulatory asset was created to record post-in-service AFUDC and deferred depreciation associated with the project until the costs are reflected in IPL's retail rates. [13]

Other infrastructure investments made to meet the ongoing need for adequate and reliable service and facilities, such as IPL's investment in its transmission and distribution

---

[10] See Ind. Code Ch. 8-1-8.4 and 8-1-8.8. IPL's MATS compliance project was approved under Chapter 8.8 in Cause No. 44242, at 38.

[11] See Ind. Code Ch. 8-1-8.4. IPL's NPDES compliance project was approved under this statute. July 29, 2015 Order in Cause No. 44540.

[12] See Ind. Code Ch. 8-1-8.5. See IURC decision in Cause No. 44339, July 29, 2015, at 40.

[13] See July 29, 2015 Order in Cause No. 44540, at 36.

system, are generally subject to the cost recovery via a general rate case, meaning that capital is advanced and the return "of'" and "on" used and useful investment follows a general rate case and depends on the rate case result and on whether the new rates produce the level of utility net operating income sufficient to allow the return "of" and "on" the investment. For these investments, there is no deferral of depreciation expense or continuing accrual of AFUDC following the in-service date of the new electric plant in service.

This filing reflects new IPL investment of nearly $1.6 billion for additions, replacements and improvements to used and useful electric utility property.[14] Of this total, $1.1 billion of new capital investment (approximately 36 percent of total rate base) is not currently included in a capital tracker or otherwise reflected in IPL's rates. This investment will not be recognized in rates until this proceeding is completed and new rates recognizing this investment are placed into effect. IPL's ability to earn a return on and of this significant investment depends on both the Commission's decision and post rate case conditions.

As noted above, this investment will not be accompanied by offsetting customer load growth. In fact, customer load will most likely continue to remain flat or a minimal increase during the period.[15] We know that other factors, such as the economy will also affect whether the rates established in this proceeding produce the authorized level of net operating income.

A supportive ratemaking decision that fully recognizes IPL's cost of service and uses the ratemaking tools available to the Commission is necessary to provide a real opportunity

---

14 Direct Testimony of Sanchez, Table 1.
15 IPL Integrated Resources Plan Volume 1, Figures 4.4 and 4.5, November 1, 2016, p. 41-42.

for IPL to earn the return of and on this investment. Absent a supportive ratemaking framework, IPL's credit profile and financial position could be compromised. The strain on utility cash flows and credit ratings could cause other desired investment to be delayed, could push utility capital costs higher and could ultimately impact the utility's access to capital. Ultimately, this scenario would translate to higher overall costs and higher than necessary rates for utility customers.

IV. DESCRIPTION OF THE IPL GENERATION ASSETS

Q25. Please describe each of the generation stations that you valued.

A25. IPL Witness JJR Attachment 2 provides an overview of the IPL Generation Assets that were in service as of June 30, 2016. Specifically, IPL Witness JJR Attachment 2 presents the name, location, operating capacity, technology, fuel type, commercial operation date, and retirement date for each of the facilities. This attachment also provides the estimated value of the asset as determined through a discounted cash flow ("DCF") analysis.

Q26. What records, information and data about the IPL Generation Assets did you review in order to develop an opinion about their value?

A26. I reviewed historical and projected information related to each of the facilities, including output, operating cost data, environmental performance, age, location, and capital expenditures.

Q27. Were the assets inspected as part of the analysis?

A27. Yes. IPL Witness Bulkley conducted an inspection of the generation assets as part of the valuation of IPL's electric utility plant. I have also visited and inspected each of the generating assets in prior years. As discussed in Ms. Bulkley's testimony, the site inspections included discussions with the plant personnel at each facility to understand the current and expected operation of each facility and to determine whether there are any material factors that would need to be considered as part of my overall valuation.

Q28. Based on the results of that inspection, do you have an opinion as to whether the IPL Generation Assets are used and useful in the provision of electric utility service?

A28. Yes. In my opinion, all of the IPL Generation Assets included in my valuation are used and useful and necessary in the provision of reliable electric utility service by IPL to its customers.

Q29. In your opinion, have you studied the IPL Generation Assets in sufficient detail to render an opinion as to their value?

A29. Yes, I have.

V. VALUATION METHODOLOGY

Q30. Please explain the income approach to valuing property.

A30. The Income Approach is defined as the measurement of "the present value of the anticipated future benefits of property ownership."[16] The DCF analysis is one generally accepted approach to estimating the value of revenue producing assets. This methodology is applicable to all types of businesses, including utilities generally and electric generation assets. The premise of any DCF analysis is that the value to an investor of an asset or investment is the cash that is able to be derived from owning that asset or investment. Using a DCF analysis, an analyst can estimate the present value of

[16] The Appraisal of Real Estate, Fourteenth Ed., Appraisal Institute, 2013, p. 46.

the expected future cash flows to be generated from an asset over a specified period of time plus any residual (or resale) value, and less any demolition costs associated with the asset at the end of the specified time. While the most significant element of value for an income producing property or asset is the present value of the expected future cash flow, the residual value of the asset, if any, must also be considered in the valuation of the asset.

Q31. What specific assets are you valuing?

A31. I am valuing IPL's generation assets that were operational as of June 30, 2016. These assets include the specific generating plants identified in Table 1. Those generating stations also include small diesel and oil-fired generators that are used for blackstart capability. The diesel and oil-fired generators would not have meaningful value in the marketplace without the remainder of the generating station and therefore have been implicitly included in the valuations developed for each of the plants. It is important to note that my analysis is valuing the generating assets as individual assets, not as part of a business or business unit of a larger corporation. Therefore, I have not considered any going concern or goodwill value that might exist if the assets were included in the sale of a going concern.

Q32. What are the advantages of using the DCF approach?

A32. The primary advantage of the DCF approach is that it provides the framework in which the numerous benefits and risks of the specific assets being valued and thus the future ongoing economic value of those assets can be quantified. This methodology is particularly useful when the expected income stream from the asset is not constant over the analytical period, as is the case with electric generating assets. Conducting a DCF analysis is one element of a due diligence effort when a potential purchaser is evaluating an income-producing asset that is not expected to have a steady income stream. The resulting value is an estimate of the market value of the assets which takes into consideration current and expected market conditions and current and expected costs.

Q33. What are the other traditional approaches to valuation?

A33. The two other traditional approaches to estimating value are the Sales Comparison Approach (valuing an asset by considering the sales prices in transactions involving the sale of comparable assets) and the Cost Approach (valuing an asset by considering its replacement cost, adjusted for its current condition). In the marketplace for generating assets, the income approach is most often relied on to estimate the value of an asset that is in operation, with the sales comparison approach often being developed to provide a check on the primary valuation approach.

Q34. Did you prepare a Sales Comparison analysis?

A34. No, I did not. While the Sales Comparison Approach can provide information about the price at which assets were transferred, in order for these data to be a meaningful indicator of the value of the subject assets, it is necessary to find examples of asset sales that are comparable to the subject asset. Establishing comparability between market transactions and the subject property can be difficult since all of the terms of a transaction are not transparent. For example, transaction value can be attributed to a variety of conditions, underlying sales and fuel agreements, market location, and going concern value. Many of these factors and terms are not publicly disclosed and therefore, it is often difficult to make the appropriate adjustments to reflect a premium or discount due to differences between the comparable group of assets and the subject assets. Furthermore, transactions that involve the purchase or sale of a corporation or interest in a going concern do not make reasonable comparable transactions for an asset valuation. The transaction value related to a corporation can be very difficult to allocate to specific assets of the business because transaction value for a corporation often includes some value related to other intangible assets such as brand, going concern value, management talent, experienced workforce, all of which would not be specifically attributed to individual assets. Therefore, I did not rely on comparable sales of assets or generation businesses in developing my opinion of the value of the IPL generation assets. Instead, I relied on the DCF approach for the purpose of valuing the IPL Generation Assets that were operational as of June 30, 2016.

Q35. Please explain how you conducted your analysis.

A35. The market value of an asset is "the price that property would sell for on the open market. It is the price that would be agreed on between a willing buyer and a willing seller, with neither being required to act, and both having reasonable knowledge of the relevant facts."[17] In order to estimate the value of the generating assets, I developed a DCF model to estimate the present value of the projected after-tax operating cash flows that would be generated by each of the IPL Generation Assets that were operational as of June 30, 2016, over the expected remaining useful life of each asset. I assumed that the assets would be acquired by a party operating in the unregulated power market and therefore I assumed that the output of the assets and the capacity value of the assets would be sold at market-based prices. Furthermore, I assumed an unregulated cost of capital.

---

[17] Internal Revenue Service, Publication 561, p. 2.

In very simple terms, net operating cash flow for each plant is calculated as follows:

Capacity Revenue (at market-based prices)
\+ Energy Revenue (at market-based prices)
− Fixed Costs (including fixed operations and maintenance expenses, administrative and general expenses, and insurance)
− Dispatch Cost (including fuel, emissions allowances, and variable operating expenses)
− <u>Income Taxes</u>
Net Operating Income
<u>− Capital Expenditures</u>
Net Operating Cash Flow

The DCF approach uses assumptions based on the historical operating experience of the IPL Generation Assets as well as projected future market conditions in order to project the net operating cash flows over the complete useful lives of each of the generating units. The total DCF value of the assets is the sum of the present value of the Net Operating Cash Flow.

Q36. What is the date of your valuation?

A36. My analysis estimates the value of the assets produced by the DCF Approach as of June 30, 2016.

Q37. What did you assume to be the retirement dates of the IPL Generation Assets?

A37. I assumed the same retirement schedule that was developed for the Company's ongoing Integrated Resource Plan ("IRP").[18] <u>IPL Witness JJR Attachment 2</u> provides a complete listing of the retirement dates that I assumed.

[18] See Indianapolis Power & Light Company, 2016 Integrated Resource Plan, November 1, 2016, p. 157.

Q38. What are the key assumptions that are included in the DCF Approach?

A38. The key assumptions in the DCF Approach include capacity and energy revenue projections, operations and maintenance expense projections, fuel expense projections, emission expense projections, capital expenditure projections, and general inflation and discount rate assumptions that were applied across all units.

Q39. Please describe the source of your capacity and energy revenue projections.

A39. The energy and capacity revenue projections used in the DCF model are consistent with those developed by ABB for the Company to be relied on in the Integrated Resource Planning process.

Q40. Please describe ABB.

A40. ABB, formerly known as Ventyx, is a leading provider of utility industry solutions for generation asset and portfolio optimization, energy trading and risk management, schedule management, price and load forecasting, maintenance optimization, resource planning, fuel budgeting, plant betterment and environmental compliance analysis. With offices in North America, Europe, the Middle East and Asia-Pacific, ABB has more than 700 clients in select asset-intensive service-based industries. ABB holds a prominent position in electricity market forecasting, serving a multitude of electric utilities, investors, banks, and others with market forecasting services in the context of strategic planning, valuation, and mergers and acquisitions.

Q41. Is ABB a reasonable and reliable source of capacity and energy market forecasts for purposes of financial analysis and valuation?

A41. Yes, it is. ABB publishes regional reference case energy and capacity price forecasts on a semi-annual basis. These forecasts are relied on by energy market participants for the purposes of valuation of energy assets. I have relied on the ABB reference case forecasts in other consulting and valuation projects.

Q42. Please explain how you used the ABB analysis in your DCF Approach.

A42. I relied on the assumptions used in the ABB portfolio dispatch modeling, as well as the resulting revenue data from that model in the DCF methodology. In relying on these data, I benchmarked the assumptions against IPL's historical data and compared market price forecasts to other available sources to verify the data set. For example, the ABB model relies on projected fuel and emissions costs. I reviewed the assumptions used in the ABB model and considered the reasonableness of those assumptions based on other available data and my knowledge of the energy markets. For operating costs, I considered the assumptions used in the ABB model as well as the operating costs reported by IPL in other public filings and historical and projected cost data provided by the Company.

Q43. Why is a market-based pricing model appropriate for valuing these assets when the IPL Generation Assets are still subject to regulation?

A43. As noted above, the purpose of my analysis is to determine the value of the IPL Generation Assets produced by the DCF Approach assuming a competitive market. This approach is also consistent with one of the traditional principles of valuation, *i.e.*, that a property or asset should be valued based on its highest and best use. This valuation can only be done if revenues are based on competitive market prices, not regulated rates. If regulated rates are used to determine revenues, the approach will become circular, because future income will depend upon the rates authorized by the regulator.

Q44. What was your source for operating expense projections used in the analysis?

A44. I relied on a combination of ABB's portfolio dispatch model and the Company's operating expense forecasts for the plants as of June 30, 2016. These projections include unit-specific heat rates, fuel costs, emissions rates, and fixed and variable operations and maintenance costs. I reviewed the forecast information for reasonableness based on the historical performance and financial results of the IPL Generation Assets.

Q45. What assumption did you make with respect to general inflation?

A45. The analysis was prepared using nominal dollars. I relied on the projected 10-year average year-over-year percent change of the Consumer Price Index as reported by Blue Chip Financial Forecasts.[19] The average for 2018 to 2022 is 2.3 percent while the average for 2023 to 2027 is 2.2 percent; the average of these two five-year periods is 2.25 percent. I used this general inflation rate to escalate fixed and variable operations and maintenance expenses and capital expenditures in periods beyond the Company's explicit forecasts for these items.

Q46. Please explain the assumptions made with respect to environmental emissions.

A46. I relied on the output of ABB's portfolio dispatch model for unit-specific nitrogen oxide ("NO_x"), sulfur dioxide ("SO_2") and carbon dioxide ("CO_2") emissions costs. These costs are the product of (1) the total heat input measured in million British Thermal Units

[19] Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, p. 14.

("MMBtu"); (2) emissions rates measured in tons per MMBtu; and (3) emissions costs measured in dollars per ton of NO_x, SO_2, and CO_2. The emissions price forecasts that were used in the study for NO_x, SO_2, and CO_2 are from the ABB Fall 2015 Clean Power Plan Carbon Tax forecast scenario. This scenario was also relied on in the Company's Integrated Resources Planning process.

Q47. Did the analysis include any consideration for future planned investments in environmental compliance?

A47. Yes. The Company provided a projection of capital expenditures for the period from 2016 through 2025. Beyond that period, I relied on an average of the expected recurring capital investment, adjusted for inflation.

Q48. How was depreciation factored into the analysis?

A48. Depreciation is a permissible deduction for tax purposes using Internal Revenue Service-prescribed accelerated tax depreciation rates. As noted earlier in my testimony, I assumed that a buyer has acquired the IPL Generation Assets at the valuation date, thereby increasing the tax basis of those assets to the level of the purchase price. I, therefore, assumed that the buyer may then depreciate the full value of the transaction for tax purposes. This assumption creates an iterative step in the valuation process, as the value of the tax depreciation is added to the asset value, and this process is repeated until negligible value is added by the next iteration. In addition, projected capital improvements in each year were depreciated going forward in the DCF model. For both purposes, I have assumed a 20-year depreciation rate under the Internal Revenue Service system known as the Modified Accelerated Cost Recovery System ("MACRS") for steam production plant (*i.e.*, Harding Street, and Petersburg) and a 15-year depreciation rate for combustion turbine production plant (*i.e.*, Georgetown and Harding Street CT). It is important to note that in the DCF analysis, depreciation is deducted as an expense in order to calculate income taxes, but is added back to calculate Net Operating Cash Flow because it is a non-cash item. Therefore, the amount of depreciation in any year affects Net Operating Cash Flows solely through its effect on income taxes.

Q49. Why did you use tax depreciation rather than book depreciation in the DCF model?

A49. The purpose of the DCF analysis is to calculate the future stream of cash generated by each facility. The depreciation amount that determines the cash needed to pay income taxes is the depreciation deductible on the income tax return. Book depreciation expense may be quite different from tax depreciation expense due to the differences in the accounting methods that are used for these purposes.

Q50. What assumptions did you use regarding tax rates?

A50. Income tax rates were based on existing Federal and existing and published projections of the State of Indiana corporate income tax rates.[20] Since property taxes are based on the value of an asset, the level of property taxes assumed in a DCF analysis in a given year is dependent on the net present value of the asset in that year. In order to avoid the circularity that results from this assumption in the DCF model, Concentric incorporated the property tax rates for the municipalities in which the IPL Generation Assets are located into the discount rate. As such, the property tax expense in a given year is dependent on the current valuation of the asset.

---

[20] The State of Indiana has published a declining corporate income tax rate beginning at 6.50 percent in 2016 and declining to 4.90 percent as of 2023. I assumed that the Indiana corporate tax rate remained at 4.90 percent in all subsequent years of the analysis.

Q51. Does the analysis consider future capital additions?

A51. Yes. The Company provided estimated capital budgets for the years 2016 through 2025, which were included in the analysis. I reviewed the capital budgets to determine those expenditures that would likely be recurring in order to derive an annual capital budget for the remainder of the useful lives of each of the IPL Generation Assets. I then added the capital expenditures for associated specific projects expected to take place after June 30, 2016, as provided by the Company.

Q52. Does your consideration of future capital additions mean that you included property that is not currently in service in your estimate of the value produced by the DCF Approach?

A52. No, quite the contrary. I deducted future capital expenditures at each facility because these expenditures reduce cash flow. Therefore, required future capital expenditures reduce the DCF value of the generating asset.

Q53. Did you include the combined cycle gas turbine generator that is planned to be constructed on the Eagle Valley site?

A53. No, I did not. I estimated the value of the existing generating assets and the projected changes in those assets. It is my understanding that the Eagle Valley Combined Cycle Combustion Turbine ("CCGT") generator will be placed into service approximately on April 30, 2017. Since there is no operating history on this asset, I did not include this asset in the DCF analysis. As discussed by IPL Witness Bulkley, the Eagle Valley CCGT is included in the Current Value of the electric utility assets at the construction cost of the unit.

Q54. Did you consider the cost of decommissioning the plants?

A54. Yes. Demolition cost estimates were provided by the Company based on a study prepared by Sargent & Lundy, L.L.C.[21] The demolition and site restoration costs were deducted from the Net Operating Income at the end of each unit's useful life.

Q55. Having derived all of the projected cash flows for the IPL Generation Assets, how did you arrive at a value for these assets using the DCF Approach?

A55. I used a discount rate to express these cash flows in the value of present-day dollars.

Q56. How did you develop the discount rate for your DCF analysis?

A56. As I noted previously, the DCF analysis produces a value for an asset in current dollars based on that asset's future cash flow stream. Future cash flows are converted into current dollars using the discount rate that is appropriate for the asset. The discount rate represents the rate of return an investor would seek for the asset being valued, and should therefore reflect the risk of the projected cash flows from the asset.

Q57. How did you calculate the discount rate for the DCF analysis?

A57. The DCF Approach is intended to establish the value of the assets to a third party in an arm's length transaction where neither buyer nor seller is under any compulsion to enter into the agreement. Therefore, the discount rate should reflect the return that is required by a non-rate-regulated merchant generator who would be purchasing the assets to sell capacity and energy at market-based rates. The discount rate includes an equity return and a cost of debt. I estimated the cost of common equity using the Capital Asset Pricing Model ("CAPM"), a well-recognized and commonly-used methodology for this purpose.

[21] Sargent & Lundy, L.L.C., "Decommissioning Study, Eagle Valley, Harding Street, Petersburg and Georgetown Stations," August 15, 2016.

My CAPM model refers to the relative market risk of four companies that are engaged primarily in the independent electric generation business.[22] The equity return for the proxy group of comparable merchant generators is 13.72 percent.

I calculated a pre-tax cost of debt as of June 30, 2016, based on the 120-day average yield-to-maturity of the Bloomberg Corporate B value curve. This curve is a composite debt rate for companies with a B rating, which is generally consistent with the debt ratings of the four independent generation companies. The average yield on the Bloomberg Corporate B Value Curve for that time period was 7.85 percent. Since interest on debt is tax deductible, I then converted the pre-tax cost of debt to an after-tax figure based on a 35.0 percent Federal corporate income tax rate and a State of Indiana corporate income tax rate. Because the State of Indiana corporate income tax rate is declining over time, the discount factor was calculated separately for each year of the analysis, reflecting the declining state tax rates.

Lastly, I estimated the capital structure based on the eight-quarter average capital structure of the proxy group of independent electric generation companies, as of March 31, 2016. The resulting capital structure is 62.46 percent debt and 37.54 percent equity.

Q58. Why didn't you rely on IPL's discount rate in your DCF analysis?

A58. IPL's discount rate reflects the risks associated with owning regulated generation as well as the risk of owning regulated electric transmission and distribution assets. Given the relatively high risk of price variation in the restructured generation markets, along with higher rates of technological failure for generating assets relative to electric transmission

[22] Calpine Corporation, Dynegy Inc., NRG Energy, Inc. and Talen Energy, Inc.

and distribution assets, the discount rate that would be required by the market to own the IPL Generation Assets in an unregulated environment is higher than the discount rate for IPL as a regulated, vertically integrated utility.

VI. <u>SUMMARY AND CONCLUSION</u>

Q59. What were the results of the DCF Approach?

A59. A summary of the results of the DCF Approach for IPL's Generation Assets is provided in Table 2 below and in IPL Witness JJR Attachment 2. The DCF Approach resulted in an overall value for IPL's Generation Assets of approximately $927.1 million or an average of approximately $339.2 per kilowatt. This is a reasonable valuation using the DCF approach.

Table 2: Summary of DCF Results

Station	Units	MW	Value ($ million)	$/kW
Georgetown	1,4	149.6	86.4	577.5
Harding Street	5,6,7	618.0	31.3	50.6
Harding Street CT	4,5,6	294.1	137.9	468.9
Petersburg	1,2,3,4	1,672.0	671.6	401.6
Total		**2,733.7**	**927.1**	**339.2**

Q60. Does this conclude your Verified Direct Testimony?

A60. Yes, it does.

VERIFICATION

I, John J. Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. and CE Capital Advisors, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

John J. Reed

Dated: December 22, 2016

RÉSUMÉ OF JOHN J. REED

Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 35 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 200 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. Has 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 and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

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, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most 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, 24, 79 and 99 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

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

ARTICLES AND PUBLICATIONS

"Maximizing U.S. federal loan guarantees for new nuclear energy," *Bulletin of the Atomic Scientists* (with John C. Slocum), July 29, 2009
"Smart Decoupling – Dealing with unfunded mandates in performance-based ratemaking," *Public Utilities Fortnightly*, May 2012

EXPERT TESTIMONY OF JOHN J. REED

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
Alberta Utilities Commission				
Alberta Utilities (AltaLink, EPCOR, ATCO, ENMAX, FortisAlberta, Alta Gas)	1/13	Alberta Utilities	Application 1566373, Proceeding ID 20	Stranded Costs
Arizona Corporation Commission				
Tucson Electric Power	7/12	Tucson Electric Power	Docket No. E-01933A-12-0291	Cost of Capital
UNS Energy and Fortis Inc.	1/14	UNS Energy, Fortis Inc.	Docket No. E-04230A-00011 and Docket No. E-01933A-14-0011	Merger
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
Federal Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Forecast 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 Allocation/Rate Design
AMAX Magnesium	12/88 1/89	Questar Pipeline Company	Docket No. RP88-93-000	Cost Allocation/Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Allocation/Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Allocation/Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Allocation/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 Allocation/Rate Design Comparability of Service
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern Distributor Group	9/92 11/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92 7/97	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
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	EC99-33-000	Market Power Analysis – Merger

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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. EC01-7-000	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. RP10-79-000	Affidavit re: Impact of Preferential Rate
Gulf South Pipeline	10/14	Gulf South Pipeline	Docket No. RP15-65-000	Business Risk, Rate Design

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
BNP Paribas Energy Trading, GP South Jersey Resource Group, LLC	2/15	Transcontinental Gas Pipe Line Corporation	Docket No. RP06-569-008 and RP07-376-005	Regulatory Policy, Incremental Rates, Stacked Rate
Tallgrass Interstate Gas Transmission, LLC	10/15 12/15	Tallgrass Interstate Gas Transmission, LLC	Docket No. RP16-137-000	Market Assessment, Rate Design, Rolled-in Rate Treatment
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
Florida Power and Light Co.	3/11 7/11	Florida Power & Light Co.	Docket No. 110009-EI	New Nuclear Cost Recovery, Prudence
Florida Power and Light Co.	3/12 7/12	Florida Power & Light Co.	Docket No. 120009-EI	New Nuclear Cost Recovery, Prudence
Florida Power and Light Co.	3/12 8/12	Florida Power & Light Co.	Docket No. 120015-EI	Benchmarking in Support of ROE
Florida Power and Light Co.	3/13 7/13	Florida Power & Light Co.	Docket No. 130009	New Nuclear Cost Recovery, Prudence

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Florida Power and Light Co.	3/14	Florida Power & Light Co.	Docket No. 140009	New Nuclear Cost Recovery, Prudence
Florida Power and Light Co.	3/15 7/15	Florida Power & Light Co.	Docket No. 150009	New Nuclear Cost Recovery, Prudence
Florida Power and Light Co.	10/15	Florida Power and Light Co.	Docket No. 150001	Recovery of Replacement Power Costs
Florida Power and Light Co.	3/16	Florida Power & Light Co.	Docket No. 160021-EI	Benchmarking in Support of ROE
Florida Senate Committee on Communication, Energy and Utilities				
Florida Power and Light Co.	2/09	Florida Power & Light Co.		Securitization
Hawai'i Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Docket No. 99-0207	Standby Charge
NextEra Energy, Inc. Hawaiian Electric Companies	4/15 8/15 10/15	Hawaiian Electric Company, Inc.; Hawaii Electric Light Company, Inc., Maui Electric Company, Ltd., NextEra Energy, Inc.	Docket No. 2015-0022	Merger Application
Illinois Commerce Commission				
Renewables Suppliers (Algonquin Power Co., EDP Renewables North America, Invenergy, NextEra Energy Resources)	3/14	Renewables Suppliers	Docket No. 13-0546	Application for Rehearing and Reconsideration, Long-term Purchase Power Agreements

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
WE Energies Corporation	8/14 12/14 2/15	WE Energies/Integrys	Docket No. 14-0496	Merger Application
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Cause No. 41746	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
Indianapolis Power & Light Company	12/14	Indianapolis Power & Light Company	Cause No. 44576	Asset Valuation
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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 Allocation/Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Allocation/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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	Merger Approval

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	2/99	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
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 Markets
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Consumer Energy Company	7/13	Consumers Energy Company	Case No. U-17429	Certificate of Need, Integrated Resource Plan
WE Energies	08/14 03/15	WE Energies/Integrys	Case No. U-17682	Merger Application
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 10/06 11/06	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
Northern States Power Company d/b/a Xcel Energy	01/16	Northern States Power Company	Docket No. E002/GR-15-826	Industry Perspective

EXPERT TESTIMONY OF JOHN J. REED

Missouri House Committee on Energy and the Environment				
Ameren Missouri	3/16	Ameren Missouri	HB 2816	Performance Based Ratemaking
Missouri Public Service Commission				
Missouri Gas Energy	1/03 04/03	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 2/06 7/06	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
Union Electric Company d/b/a Ameren Missouri	2/12 8/12	Union Electric Company	Case No. ER-2012-0166	ROE, Earnings Attrition, Regulatory Lag
Union Electric Company d/b/a Ameren Missouri	06/14	Noranda Aluminum Inc.	Case No. EC-2014-0223	Ratemaking, Regulatory and Economic Policy
Union Electric Company d/b/a Ameren Missouri	1/15 2/15	Union Electric Company	Case No. ER-2014-0258	Revenue Requirements, Ratemaking Policies

EXPERT TESTIMONY OF JOHN J. REED

Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment				
Ameren Missouri	3/16	Ameren Missouri	SB 1028	Performance Based Ratemaking
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjustment 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
Independent 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.	12/06 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

EXPERT TESTIMONY OF JOHN J. REED

Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory Policy, Toll Development
TransCanada Pipelines Ltd	9/11 5/12	TransCanada Pipelines Ltd.	RH-3-2011	Business Services and Tolls Application
Trans Mountain Pipeline LLC	6/12 1/13	Trans Mountain Pipeline LLC	RH-1-2012	Toll Design
TransCanada Pipelines Ltd	8/13	TransCanada Pipelines Ltd	RE-001-2013	Toll Design
NOVA Gas Transmission Ltd	11/13	NOVA Gas Transmission Ltd	OF-Fac-Gas-N081-2013-10 01	Toll Design
Trans Mountain Pipeline LLC	12/13	Trans Mountain Pipeline LLC	OF-Fac-Oil-T260-2013-03 01	Economic and Financial Feasibility and Project Benefits
Energy East Pipeline Ltd.	10/14	Energy East Pipeline	Of-Fac-Oil-E266-2014-01 02	Economic and Financial Feasibility and Project Benefits
NOVA Gas Transmission Ltd	5/16	NOVA Gas Transmission Ltd	GH-003-2015	Certificate of Public Convenience and Necessity
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
Atlantic Wallboard/Flakeboard	1/14	Enbridge Gas New Brunswick	NBEUB Matter 225	Rate Setting for EGNB

EXPERT TESTIMONY OF JOHN J. REED

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 & Acquisition Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acquisition 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
Public Service Co. of New Hampshire	7/14	Public Service Co. of NH	Docket No. DE 11-250	Prudence
Public Service Co. of New Hampshire	7/15 11/15	Public Service Co. of NH	Docket No. 14-238	Restructuring and Rate Stabilization
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 Allocation/Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Allocation/Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design, Weather Normalization Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Allocation/Rate Design

EXPERT TESTIMONY OF JOHN J. REED

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	1/11	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 Allocation/Rate Design
Southwestern Public Service Co., New Mexico	12/12	SPS New Mexico	Case No. 12-00350-UT	Rate Case, Return on Equity
PNM Resources	12/13 10/14 12/14	Public Service Co. of New Mexico	Case No. 13-00390-UT	Nuclear Valuation/In Support of Stipulation
New York State 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

EXPERT TESTIMONY OF JOHN J. REED

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
National Fuel Gas Corporation	9/16 9/16	National Fuel Gas Corporation	Case No. 16-G-0257	Ring-fencing Policy
Nova Scotia Utility and Review Board				
Nova Scotia Power	9/12	Nova Scotia Power	Docket No. P-893	Audit Reply
Nova Scotia Power	8/14	Nova Scotia Power	Docket No. P-887	Audit Reply
Nova Scotia Power	5/16	Nova Scotia Power	2017-2019 Fuel Stability Plan	Used and Useful Ratemaking
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
Oklahoma Gas & Electric Company	08/14 01/15	Oklahoma Gas & Electric Company	Cause No. PUD 201400229	Integrated Resource Plan

EXPERT TESTIMONY OF JOHN J. REED

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 4/96	Equitrans	Docket No. P-00940886	Rate Design, Unbundling
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 Allocation/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 3/02	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

EXPERT TESTIMONY OF JOHN J. REED

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
Cross Texas Transmission	08/12 11/12	Cross Texas Transmission	Docket No. 40604	Return on Equity
Southwestern Public Service	11/12	Southwestern Public Service	Docket No. 40824	Return on Equity
Lone Star Transmission	5/14	Lone Star Transmission	Docket No. 42469	Return on Equity, Debt, Cost of Capital
CenterPoint Energy Houston Electric, LLC	6/15	CenterPoint Energy Houston Electric, LLC	Docket No. 44572	Distribution Cost Recovery Factor
NextEra Energy, Inc.	10/16	Oncor Electric Delivery Company LLC, NextEra Energy	Docket No. 46238	Merger Application, Ring-fencing
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

EXPERT TESTIMONY OF JOHN J. REED

Texas State Legislature				
CenterPoint Energy	4/13	Association of Electric Companies of Texas	SB 1364	Consolidated Tax Adjustment Clause Legislation
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Allocation/Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90 8/90	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
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

EXPERT TESTIMONY OF JOHN J. REED

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
Northern States Power Wisconsin	10/13	Xcel Energy (dba Northern States Power Wisconsin)	Docket No. 4220-UR-119	Fuel Cost Adjustments
Wisconsin Electric Power Company	11/13	Wisconsin Electric Power Co.	Docket No. 6630-FR-104	Fuel Cost Adjustment
WE Energy	8/14 1/15	WE Energy/Integrys	Docket No. 9400-YO-100	Merger Approval

EXPERT TESTIMONY OF JOHN J. REED

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
Canadian Arbitration Panel				
Hydro-Québec	4/15 5/16 7/16	Hydro-Fraser et al v. Hydro-Québec		Electric Price Arbitration
Commonwealth of Massachusetts, Appellate Tax Board				
NStar Electric Company	8/14	NStar Electric Company		Valuation Methodology
Western Massachusetts Electric Company	2/16	Western Massachusetts Electric Company v. Board of Assessors of The City of Springfield	Docket No. 315550 Docket No. 319349	Valuation Methodology

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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

EXPERT TESTIMONY OF JOHN J. REED

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
Mitsubishi Heavy Industries, Ltd., and Mitsubishi Nuclear Energy Systems, Inc.	12/15 2/16	Southern California Edison Company, Edison Material Supply LLC, San Diego Gas & Electric Co., and the City of Riverside vs. Mitsubishi Heavy Industries, Ltd., and Mitsubishi Nuclear Energy Systems, Inc.	Case No. 19784/AGF/RD	Damages Arising Under a Nuclear Power Equipment Contract
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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 f 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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. District Court, Northern District of Illinois, Eastern Division				
U.S. Securities and Exchange Commission	4/12	U.S. Securities and Exchange Commission v. Thomas Fisher, Kathleen Halloran, and George Behrens	Case No. 07 C 4483	Prudence, PBR
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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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, Western District of Virginia				
Washington Gas Light Company	8/15 9/15	Washington Gas Light Company v. Mountaineer Gas Company	Civil Action No. 5:14-cv-41	Nominations and Gas Balancing, Lost and Unaccounted for Gas, 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

EXPERT TESTIMONY OF JOHN J. REED

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
U.S. Tax Court in Illinois				
Exelon Corporation	4/15 6/15	Exelon Corporation, as Successor by Merger to Unicom Corporation and Subsidiaries et al. v. Commission of Internal Revenue	Docket Nos. 29183-13, 29184-13	Valuation of Analysis of Lease Terms and Quantify Plant Values
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

Indianapolis Power & Light Company
Generation Assets

Line No. (a)	Plant Name (b)	Unit Number (c)	Location (d)	Capacity (MW) (e)	Technology (f)	Fuel Type (g)	Commercial Operation Date (h)	Retirement Date (i)	Income Approach Value $ millions (j)	Income Approach Value $/kW (k)
1	Georgetown Generating Station	1	Indianapolis, IN	74.3	Combustion Turbine	Natural Gas	Jun-00	Dec-40		
2	Georgetown Generating Station	4	Indianapolis, IN	75.3	Combustion Turbine	Natural Gas	May-01	Dec-40		
3				149.6					$86.4	$577.5
4	Harding Street Generating Station	5	Indianapolis, IN	100.0	Steam Turbine	Natural Gas	Apr-16	Dec-30		
5	Harding Street Generating Station	6	Indianapolis, IN	98.0	Steam Turbine	Natural Gas	Apr-16	Dec-30		
6	Harding Street Generating Station	7	Indianapolis, IN	420.0	Steam Turbine	Natural Gas	Jun-16	Dec-33		
				618.0					$31.3	$50.6
7	Harding Street Generating Station	4	Indianapolis, IN	73.1	Combustion Turbine	Natural Gas	Apr-94	Dec-34		
8	Harding Street Generating Station	5	Indianapolis, IN	75.4	Combustion Turbine	Natural Gas	Jan-95	Dec-34		
9	Harding Street Generating Station	6	Indianapolis, IN	145.6	Combustion Turbine	Natural Gas	May-02	Dec-34		
10				294.1					$137.9	$468.9
11	Petersburg Generating Station	1	Petersburg, IN	222.0	Steam Turbine	Coal	Jun-67	Dec-32		
12	Petersburg Generating Station	2	Petersburg, IN	410.0	Steam Turbine	Coal	Dec-69	Dec-34		
13	Petersburg Generating Station	3	Petersburg, IN	520.0	Steam Turbine	Coal	Nov-77	Dec-42		
14	Petersburg Generating Station	4	Petersburg, IN	520.0	Steam Turbine	Coal	Apr-86	Dec-42		
15				1,672.0					$671.6	$401.6
16	**TOTAL**			**2,733.7**					**$927.1**	**339.2**