BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CAUSE NO. PUD 200800086
GRANTING PREAPPROVAL OF THE PURCHASE	)	
OF THE REDBUD GENERATING FACILITY	)	
AND AUTHORIZING A RECOVERY RIDER	)	

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CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

John J. Reed

On behalf of

Oklahoma Gas & Electric Company

(REDACTED VERSION)

March 20, 2008

I. INTRODUCTION

Q. Please state your name and your business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Marlborough, Massachusetts 01752.

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

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

Q. Please summarize your professional experience in the energy and utility industries.

A. I have more than 30 years of experience in the energy industry, having served as an executive in energy consulting firms, including the position of Co-CEO of the nation's largest publicly-traded management consulting firm, and as Chief Economist for the nation's largest gas utility. I have advised more than 100 clients over the course of my career on a wide range of strategic, economic, financial and regulatory matters. My experience is described in more detail in Attachment A to my testimony. I have appeared as an expert witness and provided expert testimony on a wide variety of economic, financial and valuation issues related to the energy and utility industry on numerous occasions before administrative agencies, courts, arbitration panels and elected bodies across North America. Attachment B to my testimony is a list of my appearances in the past four years as an expert witness.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying on behalf of Oklahoma Gas and Electric Company ("OG&E" or "Company") in support of its proposed acquisition from Kelson Holdings LLC ("Kelson") of a 51% operating interest in the Redbud generating facility. Redbud is a 1,230 MW natural gas-fired combined cycle generating facility located near Luther, Oklahoma, less than an hour outside of Oklahoma City and within OG&E's service territory. More specifically, I have been asked to testify as to the prudence of the acquisition of Redbud. In doing so, I discuss the following:

- Policies and requirements of the Oklahoma Corporation Commission ("OCC" or "Commission") which are pertinent to the Company's proposed acquisition of Redbud and the requested approval thereof, most notably the prudence of the acquisition of Redbud (Section II of my testimony);
- Trends in the national and regional electricity market which, in part, led to the Company's decision to pursue the acquisition (Section III of my testimony);
- My assessment of OG&E's decision to consider the acquisition of Redbud (Section IV of my testimony);
- My assessment of the value paid by OG&E for Redbud based on both my independent financial valuation of Redbud and my review of comparable transactions during this same time period (Section V of my testimony); and
- The Company's proposed ratemaking treatment for the acquisition of Redbud (Section VI of my testimony).

Q. How does your testimony relate to the testimony of the Company witnesses?

A. The proposed acquisition and its benefits to OG&E's customers are described in considerable detail in the testimony of Company witness Mr. Jesse Langston. The resource planning considerations which led to the Company's proposed acquisition of Redbud are described in the testimony of Company witness Mr. Leon Howell. The Company's proposed ratemaking treatment for the acquisition is described by Company witness Jim Hatfield. Although I will cite many of the same facts, circumstances, and decisions as do Messrs Langston, Howell, and Hatfield, the focus or my testimony remains on the prudence of OG&E's acquisition of Redbud.

Q. Please summarize the principal conclusions that you reach in your testimony.

A. My principal conclusions are:

1) The Company's decision to consider the purchase of and to ultimately acquire Redbud was appropriate and prudent. Kelson's sale of Redbud presented the Company with a unique opportunity. Kelson's sale process required that OG&E

either immediately evaluate the plant outside of a traditional competitive bidding or Request for Proposal ("RFP") process or pass on the opportunity. The Company evaluated the potential acquisition of Redbud in the context of OG&E's resource planning efforts, and determined that the acquisition of an interest in this plant is the appropriate addition to its resource portfolio to meet its customers' needs.

2) The current market environment favors the acquisition of Redbud. In particular, the tightening supply and demand balance, greenhouse gas ("GHG") considerations, practical limitations on other resource alternatives in the near term, and cost pressures all make Redbud a very attractive resource.

3) The value paid by OG&E for Redbud of $852 million (or $692.7/kW) is well within the reasonable range of value for the plant based upon a discounted cash flow ("DCF") analysis of the value of the plant, an assessment of comparable transactions, and an assessment of new build costs.

4) The proposed ratemaking treatment for the Redbud transaction, namely the use of a rider to recover Redbud's annual revenue requirement until OG&E's next rate case is completed and new rates, which provide for the recovery of Redbud's revenue requirement, are implemented, is reasonable and appropriate.

5) The Redbud transaction is a good deal for customers and should remain a valuable asset in OG&E's portfolio throughout its useful life.

II. COMMISSION POLICIES

Q. Please identify Commission policies that are pertinent to the Company's proposed acquisition of Redbud.

A. The primary policy of the OCC, which must be satisfied in order for the Company's proposed acquisition of Redbud to be approved, is the prudence standard. Other pertinent and informative policies include those related to integrated resource planning ("IRP") and competitive bidding.

Q. Please describe the prudence standard.

A. The Commission considered the prudence of the Company's acquisition of a power plant in Cause No. PUD 200500151 wherein the Company requested the Commission's approval of, among other things, its acquisition of an interest in the McClain power plant. In approving that acquisition, the Commission summarized its application of the prudence standard:

> It is well settled that prudence inquiries involve a determination whether the utility management made a reasonable decision in light of the circumstances existing at the time of the decision and the knowledge of such circumstances that management had or should have had.[1]

Q. Is the Commission's summary of the prudence standard consistent with that used in common utility ratemaking?

A. Yes. In the testimonies I sponsored in Cause No. PUD 200500151, I provided a comprehensive explanation of the prudence standard, which is consistent with the standard articulated by the Commission in that proceeding. While I will not restate the full discussion that I offered in that case, I believe it is useful to highlight the principles articulated by the National Regulatory Research Institute ("NRRI"), the regulatory research affiliate of the National Association of Regulatory Utility Commissioners ("NARUC"). NRRI identified the following four principles to be followed by state utility commissions when evaluating the prudence of a utility's actions:

1) A presumption of prudence;
2) A rule of reasonableness under the circumstances;
3) A proscription against hindsight; and
4) A retrospective, factual inquiry.[2]

The Commission's application of the prudence standard in Cause No. PUD 200500151 is consistent with these principles.

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1 OCC Cause No. PUD 200500151 – Final Order, p. 103

2 *The Prudent Investment Test in the 1980s*, Burns, Poling, Whinihan and Kelly, 1984, p. 55.

Q. You indicated that IRP policies are also pertinent to the Commissions' review of the proposed acquisition of Redbud. Please explain.

A. As discussed in detail by Witnesses Howell and Langston, Section 165:35-37 establishes the procedures for the Commission's review of utilities' resource plans. In particular, the procedures require that utilities (1) submit IRP plans every three years, unless otherwise ordered by the Commission, which include strategy for, among other things, fuel procurement, purchased-power procurement, risk management, and environmental compliance; (2) monitor markets and inputs and notify the Commission of any material changes in planning assumptions; and (3) submit plans which include specific forecasts, descriptions, and assessments, and in support of their proposed IRPs. The Commission's IRP objectives include ensuring the prudence of resource planning and major investment decisions in the context of an overall "fit" in the utility's portfolio, and that the overall cost of power supply to retail ratepayers is fair, just, and reasonable.

As discussed throughout my testimony and in the testimony of Company witnesses Howell and Langston, I believe that OG&E's proposed acquisition of Redbud satisfies the Commission's IRP objectives. Notably, Mr. Howell explains that the Company has updated its resource planning analyses and based its assessment of the Redbud opportunity on a current perspective of key Company and global drivers.

Q. What are the Commission's requirements with regard to competitive bidding?

A. The competitive bidding requirements of Section 165:35-34.3(e) state that:

> Prior to a utility taking long-term procurement action other than that contemplated by these rules, a utility shall seek a waiver of all or any part of these competitive bidding rules by filing a cause with the Commission.

It is apparent that OG&E was not able to compare the acquisition of Redbud to options that may have been proposed through a competitive bidding process. OG&E did not independently seek out the acquisition of a generating facility, rather Redbud's owner, Kelson, decided to offer its assets, including Redbud, providing interested parties a targeted opportunity to consider the acquisition and present proposals. This is not at all unusual in the sale of a merchant plant by an unregulated owner. Moreover, OG&E

would not have had nearly enough time to design, issue and evaluate a competitive solicitation for long-term resources and to simultaneously comply with the transaction schedule imposed by Kelson.

Q. What are the implications of the Commission's requirements with regard to both IRP and competitive bidding for the Company's proposal to acquire an interest in Redbud?

A. While the Commission has articulated specific requirements to determine if a particular resource best satisfies the need of a utility's customers, the Commission's procedures recognize the complexity of the resource planning process and provide for a number of things:

> Establishing the need for additional resources serving as the basis for long-term ***competitive procurement*** of resources, including, but not limited to, utility construction of new electric generation facilities, the ***utility purchase of existing electric generation***, facilities, and the purchase of long-term power supplies.[3]
>
> (Emphasis added)

As discussed in more detail by Witness Howell and later in my testimony, resource planning and procurement is a complex undertaking. In some cases, traditional competitive bidding or RFP processes are the best means of securing the appropriate next resource. Conversely, in situations like the Redbud transaction, an opportunity is brought to the utility and, in the best interest of customers, must be immediately evaluated. Both of these types of resource planning processes and decisions should be evaluated in an overall resource planning context, which is consistent with my understanding of the intent of the Commission's rules. The Company was presented with a unique opportunity to purchase Redbud, which it evaluated it in the context of its IRP and in accordance with the schedule of the unregulated seller, and determined that the acquisition of an interest in this plant was the appropriate addition to its resource portfolio to meet its customers needs with regard to reliability, cost effectiveness and environmental considerations. Not

[3] OAC 165:35-37-1(4) and (7)

considering the acquisition of Redbud would have, in my opinion, been unreasonable and not in the best interests of the Company's customers.

III. ELECTRIC MARKET TRENDS

Q. Please describe recent trends in the national and regional electric market environment.

A. In recent years we have seen a number of significant changes in the electric power market. Key drivers of the market include a significant increase in concerns about GHG emissions, energy security, and energy price volatility. Deteriorating macro-economic conditions including inflationary pressures, credit availability and recessionary conditions are affecting all sectors of the economy, including the electric generation sector. Escalation of construction costs is beginning to have meaningful impacts on electricity prices. While the balance of supply and demand has returned to more of a state of equilibrium in many parts of the United States, there is still a need for resources which are environmentally friendly, reliable and cost effective. Financial markets continue to have concerns about utilities' reliance on power purchase contracts as well as the challenges to building large, base load plants. OG&E, like other utilities, faces significant challenges harmonizing all of these factors while continuing to provide adequate, reliable, and reasonably priced electric service to its customers.

Q. Why are these trends important?

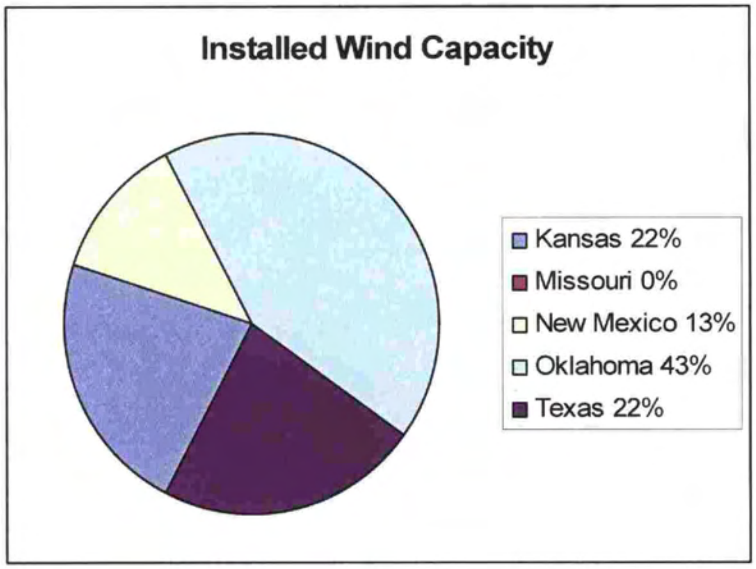
A. They are driving resource investment decisions throughout this country. Demand continues to grow, even with an apparent slowdown in the economy, and yet there are questions that remain regarding the roles that can be played by various sources of supply including coal, nuclear and IGCC plants and by demand side management ("DSM") programs.

Q. How has the increase in concern about GHG emissions impacted the market?

A. The prospect of carbon regulation is the major factor driving investment in new generation and DSM resources. It is widely believed that some form of legislation regulating carbon emissions is likely, although not until after the Presidential election.

The concern about GHG emissions has led various jurisdictions to shift policies in favor of renewable energy, new nuclear facilities, advanced clean coal facilities, and a renewed commitment to DSM, demand response measures, and strategic investment in transmission. I understand the Commission is also conducting a rulemaking proceeding to establish more aggressive DSM targets.

Oklahoma leads the five SPP states with 43% of the installed wind generation in the SPP market,[4] more than 26% of which is owned or contracted for by OG&E.



OG&E currently owns 120 MW of wind capacity and has a 15-year PPA for an additional 50 MW. OG&E has announced its intention to develop 600 MW of additional wind capacity. The transmission investment required to deliver new wind capacity to OG&E's load areas is being studied by the SPP. Further, as discussed by Witness Howell, the Oklahoma Electric Power Transmission Task Force is examining transmission investments necessary to deliver wind power to major load areas in the state.

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[4] SPP *Expansion Planning for Oklahoma and Beyond*, January 24, 2008.

In Arkansas, the 2007 Legislature created a new commission to address global warming issues. Act 696 creates a 21-member commission to study issues related to global warming and devise a comprehensive plan to address the problem.

Q. Are there particular issues with regard to wind power resources?

A. While wind -generated energy clearly has a role in the power supply mix, the availability of wind -generated energy during times of peak demand may be limited. Wind energy is clearly only available when there is sufficient wind to turn the turbines to generate energy. This is recognized by SPP in its decision to count approximately 5% of wind capacity as available capacity for the SPP system. Thus, if OG&E were to install 50MWE of new wind capacity, it would receive capacity credit for approximately 2.5MWE. Therefore, more other forms of capacity, usually natural gas-fired resources that are capable of following load, are necessary to "backstop" wind capacity and insure that there is enough capacity and energy during periods of peak demand.

Q. Please describe the role of renewable resources in this new energy economy.

A. Renewable power generation resources have received broad public support for almost two decades. The Energy Information Administration ("EIA") projects that with a continued policy push, technological advancement, and higher fossil fuel prices, non-hydro renewables will grow by 2.1% per year and could account for 11% of electric production by 2030.[5]

Q. Are other non- or minimally-GHG emitting generating resources available today?

A. No. With sufficient time, however, I believe new nuclear generation and advanced clean coal facilities will be commercially available. A current primary hurdle to both is cost and development lead times. There is strong opposition to new conventional, coal-fired generation. Advanced technologies with CO2 capture and sequestration are years away from commercial viability. In addition, it is virtually certain that new nuclear plants also

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[5] EIA Annual Energy Outlook ("AEO") 2008 Overview.

will require many years for planning, permitting and construction.[6] Natural gas-fired resources continue to be the most economical and timely of the lesser-GHG emitting resources available today.

Q. What are your conclusions regarding the combination of more robust renewables development and DSM programs to satisfy the near to mid term need for generation?

A. I do not believe these resources will be sufficient to satisfy near to mid-term needs. This is even more unlikely if we are to consider the "need" for a resource to be based on both the ability to serve load and the ability to reduce GHG emissions. The EPRI study referenced early in my testimony concluded that in order to return to 1990 levels for CO2 emissions from the power sector (the target studied), on a national level, all of the following must be achieved over the next 23 years:

- growth in renewable generation must triple;
- energy efficiency measures must slow load growth by 0.4% per year;
- the rate of efficiency improvement in clean coal technologies must double and those technologies must be retrofitted into about one-half of the existing coal fired fleet;
- carbon capture and sequestration must be widely deployed at coal plants after 2020;
- major breakthroughs in Plug-In Hybrid Electric Vehicles, which can be utilized as resources on an "intelligent grid", must be achieved and those vehicles must achieve a 30% market share by 2030; and
- the role of distributed energy resources (including distributed solar) must be increased from less than 0.1% of baseload requirements to at least 5% of baseload requirements.

Achieving any one of these objectives would be a challenge. Achieving the GHG target studied by EPRI requires that every single one of these strategies be fully successful.

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[6] Id.

Q. You mentioned construction cost escalation as drivers of energy market trends. Please explain.

A. As referenced by Company witness Langston in his testimony in Cause No. PUD 200700012, a major driver of energy prices is the cost of building new generation. In the past several years, construction cost components have dramatically increased. Raw materials (e.g., steel, cement) and manufactured products (e.g., wire, cable) costs have increased due to high global demand (and a weakening U.S. dollar) as well as increased production and transportation costs. Labor costs have grown. Additionally, large engineering, procurement and construction ("EPC") firms experienced a 37% increase in the backlog of contracts from 2005 to 2006 which may be expected to decrease the cost competitiveness of proposals.[7] This trend was discussed in detail in a recent study prepared for The Edison Foundation:

> The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic increase on the estimated cost of proposed utility infrastructure projects, which fully incorporate recent price trends.[8]

The study specifically highlights the cost of new combustion turbines, a key element of a new combined cycle facility, as rising 18% in 2006, nearly 10 times the rate of inflation.[9] The overall increase in construction costs can be seen by the trend in the Handy-Whitman Index (below).

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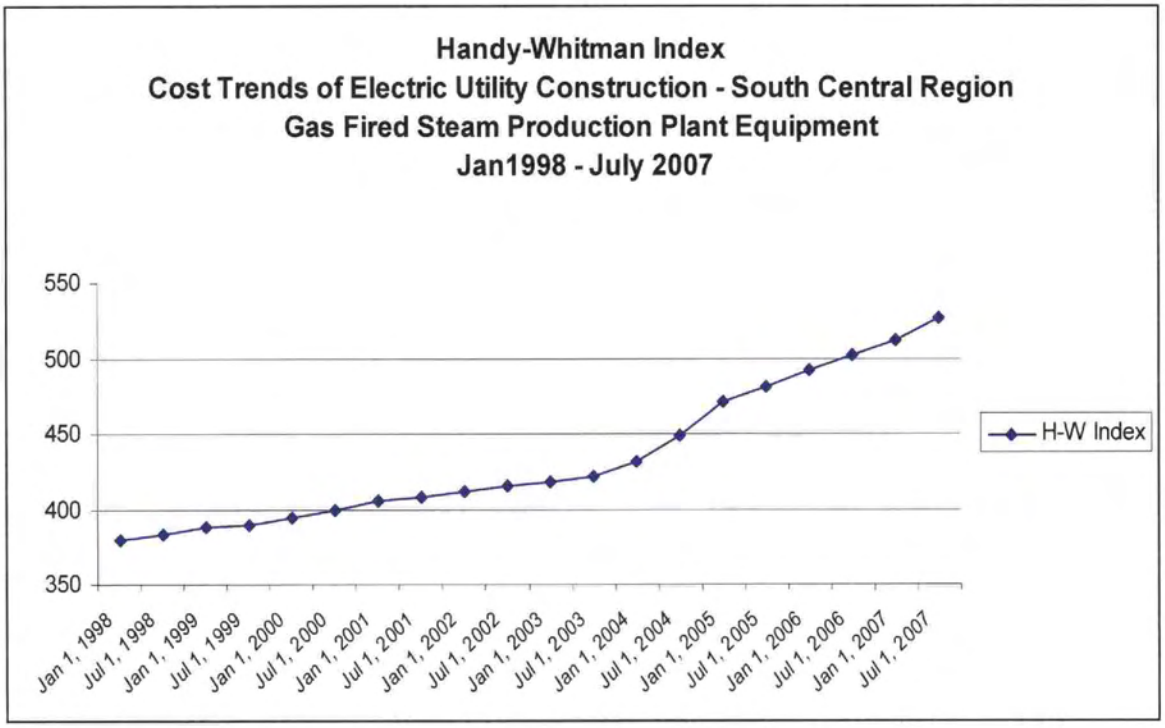
[7] *Rising Utility Construction Costs: Sources and Impacts.* © 2007. Prepared for The Edison Foundation. Prepared by: The Brattle Group.

[8] Id., p. 3.

[9] Id, p. 25.



Q. Please describe the Handy-Whitman Index.

A. The Handy-Whitman Indices show the level of costs for different types of utility construction. Separate sets of indices are published for the electric, gas and water industries. Each set of indices is maintained for general items of construction, such as reinforced concrete, and specific items of material or equipment, such as pipe or turbo-generators. These publications are used by regulatory bodies, operating bodies, operating utilities, service companies, valuation engineers, and equipment industries. Handy-Whitman Index numbers are widely used to trend earlier valuations and original cost at prices prevailing at a certain date. They are the only published construction cost indices specifically tailored to the utility industry. The electrical indices have been published semiannually since 1924, and compile construction cost indices for various categories of plant capital for the electric utility industry.

Q. Have natural gas prices increased as well?

A. Yes. As described by Witness Howell, OG&E's updated fuel forecasts predict higher and more volatile commodity prices. The lack of new coal generation is expected to drive wholesale electric prices higher as well; as such prices will reflect new gas construction costs which, as noted above, may exceed $900/kW.

Q. Please describe the changing balance of supply and demand across the country.

A. As I discussed in my testimonies filed in Cause No. PUD 200500151, a substantial imbalance of supply and demand existed during the 2001/2002 period. This imbalance was driven by a combination of reduced power demand coupled with the significant number of merchant plants being developed in anticipation of perceived deregulation opportunities.

In recent years, supply and demand has returned to more of an equilibrium condition. Demand has grown steadily (annual average growth of approximately 4.7% between 2004 and 2006).[10] At the same time, growth in supply has dramatically tapered off (approximately 1.7% over the same time period).[11] The resulting capacity reserve margins declined from a high of 21% in 2004, to a more moderate 16% in 2006. This state of equilibrium is expected to continue over the coming years. And although coal is among the least desirable resources from a GHG perspective, it is expected to continue its prominent place in our nation's resource portfolio. Of course, the balance of supply and demand is most important in the relevant market area.

Q. What has been the experience in the SPP market?

A. As described by Witness Howell, due to overbuilding earlier in the decade, SPP is in excess capacity status for the near-term. North American Electric Reliability Corporation's ("NERC's") 2007 reliability assessment projects higher average annual energy load growth in SPP – 1.8% as compared to 1.3% in its 2006 assessment. As discussed by Witness Howell, OG&E has arranged supplies to meet demand in 2008/2009, but has a projected 400 MW need for additional capacity in 2010, increasing by approximately 100 MW in subsequent years.

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[10] Source: EIA Electric Power Annual 2006. Released: October 22, 2007. Next Update: October 2008.

[11] Id.

Q. Are there other notable trends or developments in the SPP market?

A. Yes. SPP is primarily a bilateral market in which power trades are the result of negotiated contracts between specific power sellers and buyers. SPP does not have a separate capacity market. As a result, SPP is somewhat less fluid and transparent than other energy markets.

On February 1, 2007, however, SPP launched its Energy Imbalance Services ("EIS") Market. Imbalance energy is priced using locational imbalance pricing ("LIP"). This location-specific imbalance pricing varies based on market conditions at the time of the imbalance. The market participant that needs the energy, such as an entity like OG&E which serves load, pays for the amount of increase or decrease in generation at the LIP. The intent of the LIP Market is to increase market coordination, transparency and liquidity.

In addition, SPP is working on a "EHV Overlay" study to assess the viability of creating a "superhighway" of extra high voltage transmission lines (345kV, 500 kV, and 765 kV or greater). If the Redbud acquisition by OG&E goes forward, the impact on transmission costs, regional market prices, and the ability to import and export power will need to be assessed.

Q. How have the financial markets reacted to these trends in the electric markets?

A. Financial markets have reacted in several ways. First, a tightening credit market is making it much more difficult to obtain project financing for new development as well as to finance deals involving new assets.

The major ratings agencies continue to view fixed obligations under power purchase contracts as debt equivalents or substitutes for debt-financed capital investments in generation capacity. Thus, the use of PPAs may result in the imputation of debt by the ratings agencies.

The financial community is also concerned about GHG and the challenges to large base load coal and nuclear plants. Three of the nation's largest investment banks, Citigroup Inc., JPMorgan Chase & Co, and Morgan Stanley, recently articulated new environmental standards to help lenders evaluate the risks associated with investments in coal-fired power plants. The genesis of these banks' new standards is their belief that the U.S. government will cap GHG emissions from power plants, causing the banks to require utilities seeking financing to demonstrate the economic viability of their projects even under federal caps on carbon dioxide as well as to encourage energy efficiency, renewables, and low carbon distributed energy technologies.[12]

> "We have to wake up some people who are asleep," Jeffrey Holzschuh, vice chairman of institutional securities at Morgan Stanley.[13]

> "What is earth-shakingly different between now and two years ago is the focus on CO2," Eric Fornell, vice chairman of natural-resources banking at JPMorgan Chase.[14]

> "Leading utilities and financial institutions understand that the rules of the road have changed for coal... These principles are a first step in facilitating an honest assessment of electric generation options in light of the obvious and pressing need to substantially reduce national greenhouse gas pollution" Mark Brownstein, managing director of business partnerships, Environmental Defense.[15]

Q. What are your conclusions regarding the impact of the trends in the electric market on the Company's decision to pursue Redbud?

A. Appropriately valuing the Redbud opportunity must include consideration of the state of the electric market – supply and demand balance, near-term viability of various resource options, GHG implications and new build considerations. Redbud, on its face, is an attractive resource given these considerations.

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12 *Wall Street Shows Skepticism Over Coal*, New York Times, February 4, 2008, p. A6.

13 Id.

14 Id

15 *Citigroup, JPMorgan, and Morgan Stanley Unveil 'Carbon Principles'*, Environmental Leader, February 4, 2008

IV. THE DECISION TO CONSIDER THE ACQUISITION OF REDBUD

Q. Please describe your understanding of how the Company came to consider the acquisition of Redbud.

A. Company witness Langston described the Company's decision, the opportunity, and the proposed acquisition in detail. It is my understanding that OG&E was attracted to Redbud based on several factors including its location within OG&E's control area, age and condition of the plant, portfolio fit to meet near-term capacity needs, price, and as a hedge against higher CO2 prices and a tightening SPP market.

Q. Was it appropriate for OG&E to consider the acquisition of Redbud outside of a formal RFP process?

A. Yes. As noted earlier in my testimony, the Commission's procedures recognize the complexity of the resource planning process. In some cases, traditional competitive bidding or RFP processes are the best means of securing the appropriate next resource. In other situations, an opportunity like Redbud is available to the utility and, in the best interest of customers, must be immediately evaluated.

It was a practical impossibility for OG&E to evaluate Redbud and simultaneously conduct an RFP process. Kelson articulated a specific schedule for the submittal of bids to acquire Redbud. Although the original schedule was shorter, OG&E was required to submit its initial bid on November 15, 2007 providing a little more than two months before the agreements were executed. It can take up to a year to conduct an RFP process to add a significant long-term resource to the portfolio. There was insufficient time for OG&E to conduct and RFP process during the Redbud sale process.

The fact that there was insufficient time to conduct an RFP process does not in any way reflect on the Company's decision to evaluate and ultimately pursue the acquisition of Redbud on behalf of its customers. Management made the appropriate and prudent decision to evaluate a unique opportunity at the time it was presented. As described by Witnesses Langston and Howell, the Company evaluated the resource it in the context of OG&E's IRP, and determined that the acquisition of an interest in this plant is the appropriate addition to its resource portfolio to meet its customers' needs with appropriate consideration of reliability, cost effectiveness and environmental considerations. I concur with the Company.

Q. Were there other opportunities available to OG&E at the time of the Redbud acquisition that it did or should have considered?

A. OG&E periodically tests the market through RFP processes. The most recent RFP for capacity in the 2008-2010 time period resulted in approximately ten bids, but only two of the prospective sellers could actually deliver to OG&E. OG&E ultimately executed an agreement to purchase 300 MW of Redbud capacity for 2008 and 2009.

Q. You stated that Redbud presented a unique opportunity. Please explain.

A. As described by Witness Langston, Redbud has a number of attributes which make it an extremely and uniquely attractive resource to OG&E's customers. First, Redbud is located within the SPP West-Central sub-region, just outside of Oklahoma City within OG&E's control area. Due in large part to its geographic proximity to load, OG&E has periodically relied upon Redbud for peaking power. As the SPP market tightens over time, OG&E would likely have needed to acquire Redbud capacity and energy at increasingly higher prices. OG&E's acquisition of Redbud eliminates this advantage. Further, the location of Redbud should result in the lowest expenditures for transmission and system investments by OG&E.

Second, ownership of a majority interest in and operational control of Redbud presents a number of advantages. OG&E has proven itself to be a strong operator. It is reasonable to expect that, in OG&E's hands, Redbud will be well-run. Through OG&E's operations and maintenance practices, it will preserve the long-term value of the asset (including efficiency, reliability, and availability). OG&E's partners, Grand River Dam Authority ("GRDA") and the Oklahoma Municipal Power Authority ("OMPA") will share proportionate to their respective ownership interests in all costs and output.

Third, gas-fired generation is the only viable incremental mid-term option available at this point in time. The lead-time and environmental issues associated with coal-fired generation make it unviable. OG&E is already actively pursuing significant renewable (i.e., wind) and DSM investments. As discussed by Witness Howell, gas-fired generation is the best "fit" for OG&E's mid-term needs.

Finally, as discussed by Witness Langston, the acquisition of Redbud improves OG&E's overall supply portfolio. In particular, Redbud will substitute for combined cycles/combustion turbines (or PPAs based on these types of plants) to serve load, and improve the overall efficiency and reliability of the Company's portfolio (e.g., improved heat rate as compared to older gas-fired plants). Redbud will also make it possible for OG&E to expand its commitment to wind energy.

Q. Are there additional opportunities presented by Redbud which other alternatives do not offer?

A. Yes. Alternatives to the Redbud acquisition include increased renewables or DSM, contracting for supplies, or building a new plant. I have addressed the Company's efforts with regard to renewables and DSM and concur with the Company's other witnesses that OG&E is actively and appropriately pursuing these resources.

Due to the way in which the Redbud opportunity arose, contracting with a merchant generator for power supplies was not a viable option – there simply was insufficient time to conduct a solicitation. Further, as I discussed in detail in my testimonies in Cause No. PUD 200500151 and highlighted earlier in my testimony, the merchant power segment of the SPP market has faced a number of challenges that have had negative consequences in the financial markets, in particular the potential for ratings agencies to impute debt related to PPAs when considering credit ratings. Acquiring a controlling, operating interest in Redbud does not come with these negative attributes.

Aside from the fact that OG&E could not now construct a new power plant in time to satisfy its need for incremental power, the acquisition of Redbud insulates the Company from cost risk. As discussed in Section V of my testimony, the price paid by the Company for Redbud is lower than the cost of new construction. Further, as discussed in Section II of my testimony, construction costs have dramatically escalated over time. As "steel in the ground", Redbud is not subject to development and construction cost risks and has interconnections in place to natural gas and electric transmission facilities. Further, the acquisition of Redbud decreases the need to purchase power in a tightening SPP market. The acquisition of Redbud locks in a favorable price for capacity, removing both construction cost risk and increasing purchase power costs.

Q. Was OG&E's decision to pursue the acquisition of Redbud prudent?

A. Yes. The combination of all of these benefits offered by Redbud, coupled with the financial value of the plant described in Section V of my testimony, support the prudence of the Company's actions and decisions. Not considering the acquisition of Redbud would have, in my expert opinion, been unreasonable and not in the best interests of the Company's customers.

V. ASSESSMENT OF THE VALUE PAID FOR REDBUD

Q. Please describe the valuation you performed of Redbud.

A. The objective of my valuation study was to establish the range of value that OG&E and its customers would enjoy, and therefore should be willing to pay, for Redbud. The valuation study consisted of three parts. First, I calculated the merchant value of the plant using a Discounted Cash Flow ("DCF") model ("Merchant Value Present Value Analysis"). The Merchant Value Present Value Analysis attempted to quantify, on a DCF basis, the value of the plant in the marketplace today as a merchant plant. In theory, in order to acquire Redbud, OG&E and its partners need to pay what both the seller and the market generally believe to be the plant's "market price". If OG&E had the opportunity to conduct an RFP, the Redbud plant would have been compared to other merchant facilities offered in response to the RFP. Determining the merchant value of the plant to OG&E is one element in establishing a prudent valuation for Redbud.

Next, I performed an analysis of what it would cost to build a new plant like Redbud today ("New Build Value Analysis"). Given OG&E's current short-term supply surplus, one would expect some discount off full new build costs.

Third, I examined other recent transactions for gas fired generating plants ("Comparable Value Analysis"). While my Comparable Value Analysis was challenged by the lack of a meaningful sample of similar transactions, it still provides valuable input regarding the marketplace for gas fired generating plants.

Finally, I established the range of reasonable values for the plant in consideration of each of the above analyses and my assessment of other, strategic value offered by the plant.

Q. Please describe the Merchant Value Present Value Analysis.

A. The Merchant Value Present Value Analysis relied upon a DCF model. A DCF analysis calculates the current value (the Net Present Value or "NPV") of an asset based upon the estimate of its future after tax cash flows discounted to a current or present value at an appropriate after tax discount rate. DCF analysis is a commonly used tool for this type of financial examination and is used by most acquirers and investors when valuing assets.

The key inputs to a present value analysis include forecasts of revenue, expenses, future capital expenditure requirements, income tax rates, and the discount rate. For a merchant plant, revenue is based on selling energy and capacity into the market going forward, including short term sales and potentially longer term sales under contracts. The ability to generate revenue depends on the expected market or contract pricing for electrical energy and capacity coupled with the plant's operating and locational characteristics. Expenses include the cost of fuel (natural gas) and the fixed and variable operating costs of operating the plant (which includes taxes of various types). Future capital expenditures include those required expenditures to maintain the plant's operating performance and make regular and necessary overhauls or replacement of equipment.

The discount rate, or "cost of capital", is the rate at which the after tax cash flows are "discounted" to determine the present value of a project. In theory, the discount rate is the rate of return that investors would require on projects and investments with similar risk characteristics to the project being analyzed.

The NPV result of the DCF modeling is an important indicator of the appropriate valuation of the plant. However, this is not the only method of valuing the plant and there may be reasons to pay more or less than the DCF value, as I will discuss later in my testimony.

Q. Please describe the key inputs and assumptions underlying your DCF analysis.

A. As noted above, a DCF analysis requires a forecast of expected future revenues and costs. I developed the necessary information based on a number of sources, including plant costs information received from Kelson (the seller) during the due diligence process (which was modified somewhat by OG&E based on their knowledge of their similar plants) such as McClain), various forecasts (energy and capacity prices, fuel costs, CO2/carbon taxes) from the forecasting firm of Global Energy Decisions ("GED") which was retained by OG&E to perform these analyses, and my own professional expertise. Underlying all elements of the valuation were the following assumptions:

- A January 1, 2009 "start date" for the valuation which assumes that ownership of the plant would transfer to OG&E on that date.
- An analysis period of 30 years from the January 1, 2009 start date which assumes a useful life of the plant of approximately 34.5 years, given that the plant entered service in mid 2004.

Q. Please discuss your revenue projections methodology.

A. OG&E engaged GED to develop revenue, fuel costs, and operating forecasts for the plant. As noted earlier, the goal of the DCF analysis is to determine the market value of the plant as a "merchant plant". I attempted to consider both the "capacity" value of the plant, usually considered to be the value of payments necessary in the market to recover the fixed costs of a plant (including the cost to build or acquire the plant) and the "energy" value, usually considered to be the value or payments necessary to recover the marginal costs of running the plant (including fuel). GED has sophisticated capabilities to model the SPP and surrounding regions to forecast how often the plant would be expected to operate in the marketplace and to estimate the pricing the plant would receive in the market for the energy generated. Furthermore, GED has the capability to estimate the value of "capacity" in the marketplace and I relied upon GED's projections of the value of capacity over the 30-year valuation period.

GED assumes a 2.5% general inflation rate in all of its projections for energy, capacity, and fuel costs.

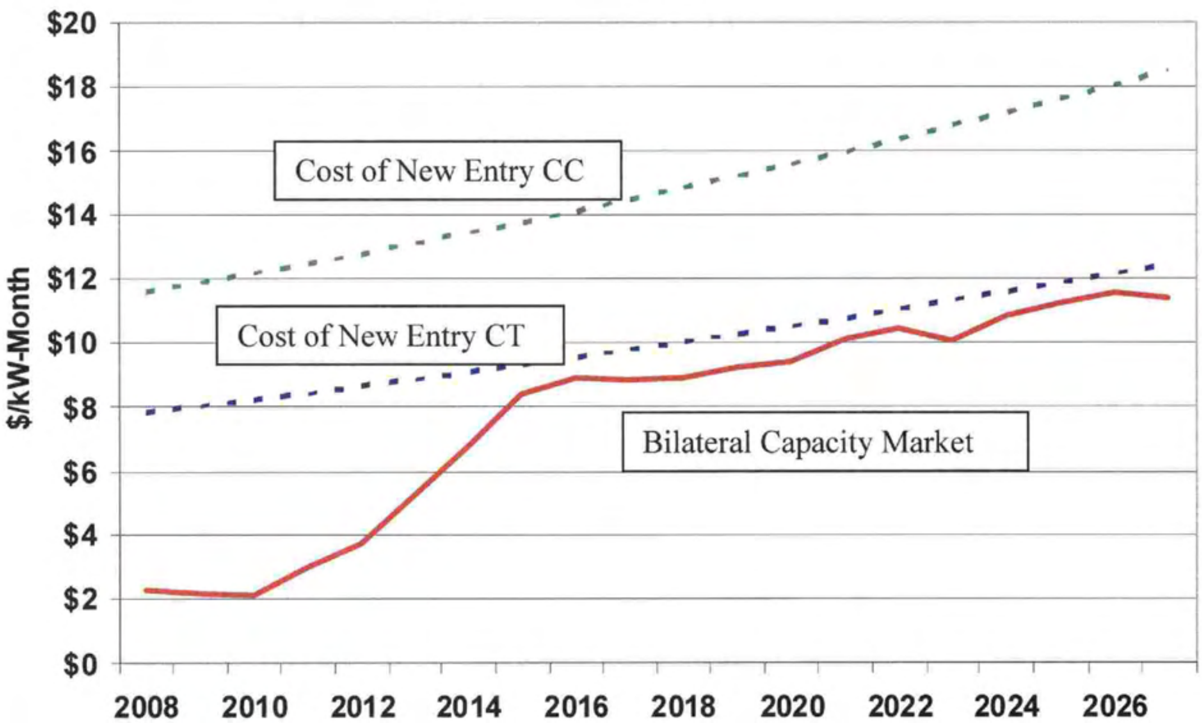
Q. Please discuss the valuation of "capacity" that you referred to above.

A. Developed wholesale energy markets, such as the New England ISO, have mechanisms that provide "capacity payments" to owners of generation facilities. Usually, these payments are described in terms such as \$/kW-month or \$/kW-year. While the capacity payments are designed to allow generation owners to recover the fixed costs of their plants and provide an incentive to build new plants, the capacity payments are sensitive to market conditions. In regions or during periods where there is excess generation, low or no capacity payments might be normal because there is considerable excess capacity. In regions where capacity is short, the capacity payments would generally rise to levels at, or even above, those levels necessary to support the construction of new capacity.

The SPP region does not have a "formal" capacity payment process. However, capacity payments can be structured on a bi-lateral basis, between a willing buyer and a willing seller. As an example, in an arms-length transaction negotiated in 2007 before this acquisition was contemplated, OG&E contracted with the Redbud plant for 300MW of capacity for the summers of 2008 and 2009. OG&E agreed to pay Redbud $**REDACTED**/kW-month ($**REDACTED** per month per kilowatt of capacity) in 2008 for the 4 "summer" months of the year, equivalent to $2.33/kW-month if paid over the full year. The price for 2009 is $**REDACTED**/kW-month, equivalent to

$REDACTED/kW-month if paid over the full year. OG&E has indicated to me that both OMPA and GRDA, the co-purchasers of the Redbud plant with OG&E, have contracts in place with the Redbud plant that include capacity payments.

GED estimated the future "value" of capacity in the SPP region. The values, as shown on the chart below, start in 2009 at $2.09/kW-month and escalate to $8.65/kW-month in 2015. GED is assuming the growing demand for power in the region will absorb excess capacity and will reduce the reserve margin, thus the "value" of capacity will increase significantly. As one can see on the chart, GED's expectations for the capacity value rises to a level approximately equal to the cost of constructing a new gas turbine facility in the region. A single cycle gas turbine (combustion turbine or "CT") is generally considered to be the cheapest form of capacity available.



I have used these capacity values in my analysis as the basis for capacity revenue available from the plant over its life. Essentially, the assumption is that if Redbud remained as a merchant, one or more load serving entities would contract with the plant (in the absence of a formal SPP capacity market) for its capacity, just as OG&E did for a portion of the plant's capacity in 2009. I assumed that the amount of capacity sold is equal to the lower summer capacity value of the plant (1,160MW).

While I believe that GED's analysis is reasonable, it may be conservative. GED's forecasted capacity value never exceeds the cost of a new combustion turbine. If capacity tightens significantly in the market in the absence of new generation (keeping in mind that some forms of generation, such as wind power, have limited capacity value), I believe that the capacity value could rise much higher than that forecasted by GED for periods of time. Furthermore, the costs of new facilities is growing at very high rates of inflation (as utilities experienced relative to recent previous plans to build new facilities) and it is likely the cost of new capacity could be significantly above the numbers estimated by GED and shown on the chart. This increase in the cost of new capacity is discussed later in my testimony.

Q. Please describe the energy revenue projections.

A. Again, I relied upon GED's projections for the value of energy over the 30-year valuation period. GED's models include data on plant costs and capabilities for all generating facilities in the SPP region (as well as transfer potential to/from other regions) and also include forecasts of plant additions and retirements. GED's model sets up a dispatch order and assumes that the lowest cost plants operate each hour (subject to plant characteristics) to meet the forecasted load. This dispatch order also determines the price of power in the marketplace each hour (the price of power in the market would normally be equal to the cost or price of power from the highest cost or "marginal" generator that is operating during that time period). Therefore, the GED model provides an estimate of the amount of time that the Redbud plant would operate in a "merchant" mode and the revenues that the plant would earn during its hours of operation if the plant were not acquired by OG&E.

GED projects that the capacity factor of the plant would rise from a level of approximately 28.0% in 2009 to a peak of 34.2% in 2016. It would then decline slowly through the end of its life. This reflects several factors:

- Redbud, and other gas plants, will tend to run only during peak hours. SPP's coal plants (which are cheaper to run on a marginal basis) are able to supply much of the load during off peak times.
- Growing supplies of wind energy (which has a near zero marginal cost) supplant energy sales from plants such as Redbud. It should be noted that although wind power is a good source of energy at times, there is limited capacity value in wind power, given that wind energy is only available when the wind blows, an uncertain element. I understand that SPP, for example, which requires load serving entities to maintain certain capacity margins during the summer periods, allows only a limited amount of wind capacity to be actually counted in its capacity margin calculations.
- In the latter years of the plant's life, GED assumes that more efficient new generators are developed and come on line in the SPP region. Therefore, Redbud becomes a relatively more costly energy producer and would be supplanted by the more efficient generators during many hours of the day.

GED's analysis takes into consideration transmission constraints between SPP and other regions and also between SPP Central (where OG&E and Redbud are located) and other SPP sub-regions. It does not, however, consider transmission constraints within SPP Central itself. This could have both positive and negative impacts on the merchant value of Redbud. On the negative side, transmission constraints could limit Redbud's potential market within SPP Central, reducing the potential number of buyers and limiting potential sales from the plant. On the positive side, potential purchasers close to Redbud may have been limited in their ability to contract with generators or utilities farther away in SPP Central, thus forcing them to purchase more power from Redbud than they would have in a market without transmission constraints. I am comfortable that in the context of this overall analysis, these two factors are likely to have an offsetting impact on the analysis.

Q. Please identify the Redbud-specific cost inputs and assumptions.

A. Key Redbud-specific costs include fixed and variable operational costs, capital expenditures, depreciation and amortization, and taxes.

Operational cost inputs and assumptions were developed primarily based upon budgets and forecasts produced by Kelson and OG&E's own assessment of this information through its due diligence on the plant, and its own experience in operating the McClain facility. Key assumptions are as follows:

- Fuel costs were obtained from GED. GED uses estimated fuel prices as an input to developing power market prices (since the price of energy in the market is heavily determined by the cost of fuels). Therefore, it is appropriate to use GED's natural gas pricing forecasts in our analysis for consistency. GED used the ANR SW pricing point for natural gas.
- Non-fuel fixed costs are estimated to be approximately $15 million in 2009 (excluding property taxes), and escalate. While costs are estimated to increase at a rate of 2.5% per year in the latter years, OG&E estimates that costs are increasing at a higher rate currently and I used a 4% inflation rate through 2012.
- Variable costs are assumed to be $1/MWHR of generation.
- Property taxes are assumed to be approximately 1% of the purchase price ($8.5 million per year is assumed) and do not escalate with inflation, given that the plant is a depreciating asset.
- Capital expenditures are primarily assumed to be a major overhaul of each turbine of the four turbines every four years, with a cost of $8 million per turbine (escalating with inflation) assumed. Other capital expenditures are assumed to be approximately $300,000 per year and increase with inflation.

- 20-year MACRS tax deprecation is assumed on the plant. This is the method of tax depreciation that OG&E (and other potential buyers) would use for the major equipment in the plant.
- A carbon tax, beginning in 2012, is assumed in the analysis. The 2012 level is assumed to be \$2.30/ton of CO2 and it rises to \$30.70/ton in 2038, the end year of the analysis. This assumption was obtained from GED. Given that the overall level of energy prices will be impacted by any CO2 tax and the mix of generating units, it is important to use GED's forecast to maintain consistency throughout the analysis. The small costs of SO2 and other environmental pollutant removal is assumed in the variable cost assumption.
- A combined federal/state income tax rate of 38.7% is utilized in the analysis, which includes a 5.69% Oklahoma state income tax rate.

Q. Please identify other inputs and assumptions.

A. A general inflation level of 2.5% was assumed throughout the analysis. This is a figure that OG&E has used in previous analyses and is consistent with GED's projections. As noted above, certain costs were inflated at higher levels for some years based on OG&E's input.

I assume that there is zero terminal value to the plant in 2038, the end date of my analysis (I assume that the demolition costs are offset by scrap value). This may be a conservative assumption given that many well-maintained generating plants operate for 50 years or more and the Redbud plant may have continuing value as a "peaking" plant after 2038, even assuming that newer generators have come on line.

Q. How did you develop the appropriate discount rate for the analysis?

A. Because I am evaluating this plant on a "merchant" basis, it is appropriate to utilize a discount rate that is consistent with the risk characteristics of merchant plants generally. My analysis indicates that the appropriate after tax discount rate for a merchant plant in the applicable market is approximately 8.8%. This compares with an OG&E after tax discount rate, based on its capital structure and costs of debt and equity, of 7.62%. The higher discount rate that I have utilized resulted in a significantly lower valuation than if I had used the actual OG&E discount rate.

To develop this discount rate, I examined the financial characteristics of the three publicly traded independent generating companies: AES Corp., NRG Energy, and Reliant Energy, as shown in the table below:[16]

Company	Ticker	Domicile Code	Industry Name	Beta	% Common Equity/Capital	% LTD/Capital Latest Qtr
AES Corp.	AES	US	Power	1.25	16.93	82.93
NRG Energy	NRG	US	Power	1.05	40.58	59.48
Reliant Energy	RRI	US	Power	1.20	55.42	41.4
MEAN				1.17	37.64	61.27
MEDIAN						
MEAN EXCL. AES				1.13	48.00	50.44

As is shown, the mean beta of the companies is 1.17 and the common equity to capital ratio is 37.64% (although excluding the highly levered AES Corp the equity ratio is 48.0%). I used a 45% equity ratio in my analysis given that it is within the range of the two figures and is more conservative than the mean of the three companies.

I then developed the appropriate return on equity using the capital asset pricing model ("CAPM") methodology. This methodology provides that the required equity return is equal to the risk free rate plus the market risk premium times beta. The risk free rate utilized is 4.5%[17]. The market risk premium utilized is 7.1%[18]. Taking the risk free rate plus the market risk premium times the adjusted beta of the companies (1.21)[19] provides a desired after tax return on equity of 13.08%.

[16] Information on capital structures and betas from Value Line
[17] Blue Chip Financial Forecasts risk free rate Q1 2009
[18] Morningstar, Inc. 2007 Yearbook Valuation Edition
[19] Adjusted upward from 1.15 due to the use of a 45% equity ratio

To complete the analysis and develop the appropriate discount rate, I researched the appropriate interest rate for BB companies, which is 8.5%, a 400 basis point premium over the risk free rate[20].

Applying the 55/45 debt/equity ratio previously describe, to the 8.5% debt rate and 13.08% after tax cost of equity, and considering the 38.7% state and federal consolidated income tax rate applicable in Oklahoma, results in an average cost of capital or WACC of 8.8%. I utilized this 8.8% WACC in my analysis of Redbud.

It is important to note that this discount rate is appropriate for a merchant plant in today's market in a relatively "balanced" power supply region such as SPP, but the rate may have been much different (higher) even a year ago or in a different region. As power supplies have tightened in many regions, the value of merchant plants has increased. Investors see lower risk in buying a merchant plant in today's market, where plants can operate at higher capacity factors and potentially receive growing capacity payments than they did a few years ago, where many plants would rarely operate due to excess capacity.

The most direct example of this is in the comparison of OG&E's purchase of McClain versus this proposed purchase of Redbud. McClain and Redbud are fairly similar plants, both combined cycle gas turbines, and both fairly strategically located within OG&E's service territory. OG&E was able to purchase the McClain plant for approximately $400/kW in 2004. The valuations of plants have increased markedly in that time frame (as I will discuss later in my testimony when looking at comparable transactions) and the value of Redbud (and McClain) have increased.

Q. Please review the results of your DCF analysis.

A. My deterministic analysis consisted of a base case and various scenario analyses. The base case DCF analysis, using the parameters discussed above, results in a net present value of the plant of $**REDACTED**/kW, as compared with the proposed purchase price

[20] CEA estimate.

of $692.7/kW (based on 1,230 MW of total plant capacity). This excludes any strategic value to OG&E from the plant, as I will discuss later in this testimony.

I performed various sensitivities around the base valuation, including variations in discount rate, energy margin, capacity pricing, and operating costs. The results are shown in Schedules JJR-1(a) through JJR-1(d). The results are most sensitive to changes in the discount rate, and least sensitive to changes in operating costs. As an example, if OG&E's 7.62% after tax discount rate is utilized, the value of the plant rises significantly to $**REDACTED**/kW.

I also performed a "stochastic" analysis. The stochastic analysis as done here considers a number of potential operating scenarios for the plant and determines an "average" valuation. GED provided information on revenues and fuel costs for 50 potential operating scenarios for the plant. I took the mean of this information and developed an NPV based on this data. The value of the plant using this information (keeping constant the discount rate and costs that were used in the base analysis) was $**REDACTED**/kW, compared with the proposed purchase price of $692.7/kW.

While not the primary purpose of this DCF analysis, the value of the plant based on OG&E's discount rate should not be completely ignored. There is clearly "strategic" value to OG&E over and above the "merchant" value of the plant (as described more fully in the next answer). Given that SPP is not a fully "integrated" or "least cost" market, Redbud as an OG&E plant is likely to run more than it would have as a merchant plant, and OG&E can dispatch the unit to displace its higher cost generators. Because of this and because of other factors such as the increased certainty and reduction in volatility that ownership brings to OG&E as opposed to the uncertainty of having to procure power in the market or to build a new plant when plant construction costs continue to rise, Redbud should have more value to OG&E than to other potential bidders. Furthermore, Redbud's location within the OG&E footprint and near the Oklahoma City load center is very valuable to OG&E. My DCF analysis, however, shows that OG&E is paying a price slightly under the value of the plant as a "merchant" plant in the marketplace today. It is not paying a "premium" for the OG&E strategic value issues mentioned here.

Q. Please describe the other sources of value you considered in your analysis.

A. While I did not include any "strategic" valuation potential to OG&E in my DCF analysis, I have considered various other sources of strategic value to OG&E in reviewing the value of owning 51% of Redbud. I previously discussed the various locational advantages Redbud offers. As discussed by Company witness Crissup, limited transmission investment will be needed to make full use of the 51% of Redbud that OG&E is proposing to acquire. Redbud will also provide immediate savings to OG&E due to the higher heat rate and lower cost of operation as compared to some of OG&E's older, less efficient plants. Finally, Redbud offers significant operating flexibility and optionality. Redbud's four CT/HRSG combination provides greater operating flexibility than plants with larger sized individual units. The plant's ability to cycle on and off line fairly quickly to respond to favorable market conditions would provide "option value" to OG&E.

Q. Please summarize the results of your Merchant Plant Valuation.

A. Based upon my assessment, described above, the reasonable range of value for Redbud is between $**REDACTED** million (or $**REDACTED**/kW) to $**REDACTED** million (or $**REDACTED**/kW) with a base deterministic valuation of $**REDACTED** million (or $**REDACTED**/kW). The stochastic valuation, which considers an average of the impact to revenues and fuel costs of 50 potential scenarios, is $ **REDACTED** million (or $**REDACTED**/kW). The base deterministic valuation and the stochastic valuations are both above the price being paid by POG&E and its partners for Redbud.

Major drivers of value include the bilateral capacity value assumed for the plant, the discount rate (WACC) assumptions, and the energy value due to running times and gross margin available from energy sales. Utilizing OG&E's lower WACC (7.62% versus the base merchant WACC of 8.8%) results in a significant increase in plant valuation, to approximately $**REDACTED** million (or $**REDACTED**/kW). I should note that my

Merchant Plant Valuation analysis does not include the sources of other value discussed above, including the locational advantages and the potential substitution of Redbud power by OG&E for more expensive power generated from other OG&E plants. Also, I did not take into consideration the potential higher capacity value that would result from higher future plant construction costs or from the use of a combined cycle plant as the "value" of capacity.

The purchase price of $852 million (or $692.7/kW) being paid by OG&E and its partners is well within the reasonable range of value for the plant

Q. Please describe the New Build Value analysis.

A. For comparison purposes, I developed an estimate of the all-in cost to OG&E to build a new combined cycle generating facility. In doing this, I relied on recent engineering information prepared by Sargent & Lundy, a well known engineering and construction firm, on costs of new generating facilities. OG&E engaged Sargent & Lundy in late 2007 to prepare this information as part of its integrated resource planning process[21].

In early 2008, Sargent & Lundy provided estimated "overnight" costs to construct facilities in 2008 dollars. These "overnight" costs include all of the equipment and other construction related costs of the plant expended over the construction cycle for a plant completed in 2008. However, these costs do not include AFUDC during construction, owner's costs, and transmission related costs, appropriate costs to include in my analysis.

Sargent & Lundy provided costs for several different types of combined cycle natural gas plants (as well as for other types of generating facilities). For purposes of my analysis, I utilized the cost of a new 2x1 General Electric 7FA combined cycle plant configuration. The 2x1 configuration involves 2 combustion turbines connected to one steam turbine. I utilized this configuration because OG&E indicated to me that this is the type of plant that it would build, absent the acquisition of Redbud, probably at the McClain site. This

[21] Sargent & Lundy preliminary analysis dated 2-4-08.

configuration is consistent with the design of the existing McClain plant. It is also the least expensive configuration to build, and, therefore, the most conservative value to use in my analysis. If I had used the 1x1 configuration similar to that of the Redbud plant, the "overnight" cost, according to the S&L estimates, would have been between 1% and 18% higher[22].

To obtain the total cost of the hypothetical plant on a comparable basis to Redbud when placed in service, I have included certain other costs that were provided to me by OG&E. These include the estimated costs of transmission improvements necessary to equalize the transmission position of a new plant built at the McClain site versus value of the existing plant at the Redbud site[23]. I also include estimated "owners costs" that are not included in the Sargent & Lundy overnight costs[24]. I further added in approximate AFUDC costs as the normal allowance for financing costs during construction. Transmission costs are in 2006 dollars and I have escalated them at 2.5% per year for inflation, the rate that OG&E often uses in its analysis. However, this rate would be highly conservative given the recent cost increases experienced by utilities in construction projects[25]. While I cannot comment specifically on the values used for the transmission costs, it is clearly appropriate to consider this cost in the analysis.

Finally, I inflated all costs by one year to 2009 dollars. This equalizes the new build cost to the cost of purchasing the Redbud plant at the expected closing date, which is early in 2009 or late in 2008. Again, I used a highly conservative 2.5% inflation rate.

As shown in the table below, Sargent & Lundy's capital cost estimates, when combined with OG&E's estimates of the other costs noted, resulted in a new build cost per kW of $953 in 2009 dollars. These figures are shown in the table that follows.

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[22] Id.
[23] OG&E Resource Plan dated 1/2/07, Appendix E, E14 (doubled to account for 1,000MW plant)
[24] Sargent & Lundy estimated owner's costs at 8-10% of capital costs. 9% was utilized.
[25] From "Rising Utility Construction Costs, Sources and Inputs" prepared by the Brattle Group, September 2007.

Cost of Construction of a New 2x1 Combined Cycle Generating Plant

Cost Element	$/kw		Source
Capital Costs	$754	*	Sargent and Lundy
Owner's Costs	$68	*	Sargent and Lundy
Transmission Cost	$48	*	OG&E
AFUDC	$60	*	CEA Calculation
Sub - Total (2008 $)	$930	*	
Inflation to 2009	$23		2.5% per annum for 1 year
Total (2009 $)	$953		

* In 2008 Dollars

This $953 cost per kW in 2009 dollars in well in excess of the price of $692.7 per kW being paid for Redbud.

However, it is appropriate to consider that the Redbud plant will be five years old when it is purchased. This would suggest that the Redbud plant would have a 5 year shorter in-service life span for OG&E than a new plant. To account for this, I net out 5 years of depreciation on a straight line basis from the cost to build a new plant. Assuming that this type of plant has a 35 year life span (which is consistent with the life span I used in my DCF analysis), annual depreciation on the plant at the $953/kW is $27.2 per year per kW. The expanded table below includes the impact of this depreciation.

Cost of Construction of a New 2x1 Combined Cycle Generating Plant

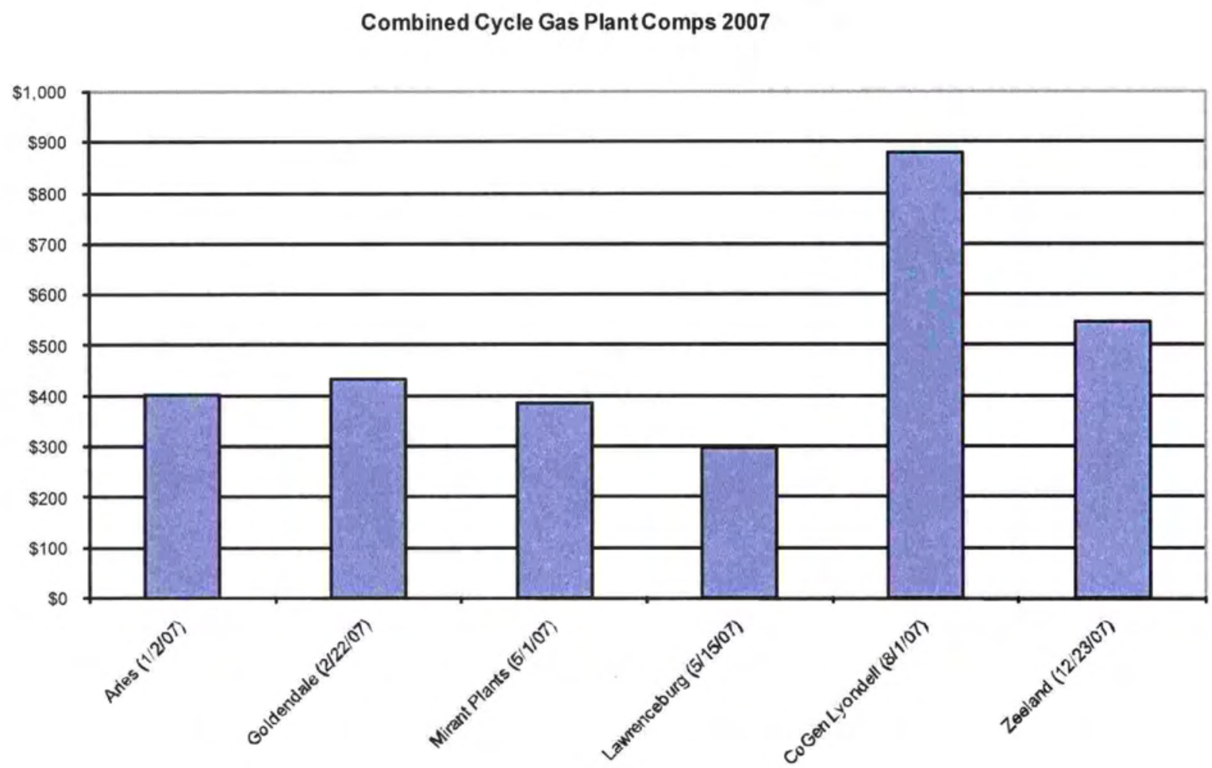
Cost Element	$/kw		Source
Capital Costs	$754	*	Sargent and Lundy
Owner's Costs	$68	*	Sargent and Lundy
Transmission Cost	$48	*	OG&E
AFUDC	$60	*	CEA Calculation
Sub - Total (2006 $)	$930	*	
Inflation to 2009	$23		2.5% per annum for 1 year
Total (2009 $)	$953		
Depreciation	$136		5 years straight line
Net (2009 $)	$817		

* In 2008 Dollars

Consideration of the 5 year age of the Redbud plant at the projected time of approval of its purchase reduces the effective cost to construct to $817/kW. However, this cost is still well above the $692.7/kW cost of Redbud. My analysis suggests that the cost of the Redbud plant is well below the cost of constructing a similar new facility.

Q. Please describe the Comparable Value Analysis.

A. I have examined other transactions involving natural gas fired generating plants in 2007 to produce a "comparable" range of sale values. These values are shown on the chart below. The sale values cover the range from $297/kW to $880/kW with a mean of $491/kW. While the price being offered for Redbud is within the range, it is above the mean paid in other transactions. As discussed earlier in my testimony, Redbud offers a number of strategic advantages which, in my opinion, justify a purchase price which is above the mean of my Comparable Value Analysis.



Q. What is your assessment of the comparability of these transactions to the Redbud transaction?

A. There are considerable differences in the transactions noted in the comparables chart above from the Redbud transaction which makes the comparables information difficult to rely upon for valuation guidance. Of primary importance is that four of the six transactions closed in the first 5 months of the year and were priced in 2006 or early in 2007. I believe that the "market value" of natural gas fired plants is rising as it becomes much more difficult to build coal fired power plants due to environmental issues (the 2007 decision by the OCC that forced the cancellation of the Red Rock coal fired facility is an example). In my opinion, the value of a natural gas fired plant now is generally much higher than in 2006. An example of this is that the two transactions completed late in 2007 are the transactions with the highest prices (an average of $713/kW).

Also, as to the first two transactions set forth in the chart above, the Aries and Goldendale transactions, were sold by a bankrupt entity in power markets where reserve margins were high, over 20%.[26] These two factors would tend to reduce values below where they might otherwise be in a more normal market environment.

Q. What is the importance of GRDA's and OMPA's acquisition of ownership interests in Redbud when assessing the reasonableness of the value the Company proposes to pay for Redbud?

A. The fact that two additional and knowledgeable buyers assessed the value of Redbud to be at least equal to the value assessed by OG&E is very relevant and informative. Both GRDA and OMPA will acquire an ownership interest in Redbud at the same purchase price and under the same general terms of the transaction as will the Company. Those transactions are the most recent, relevant, and comparable transactions to OG&E's Redbud transaction and provide independent support for the Company's valuation.

Q. What are your conclusions regarding the value proposed to be paid by OG&E for Redbud?

A. OG&E's purchase price of $852 million (or $692.7/kW) is well within the reasonable range of value for the plant.

VI. RATEMAKING TREATMENT

Q. Please summarize OG&E's proposed ratemaking treatment for Redbud.

A. As described in detail by Company witness Hatfield, OG&E proposes to recover Redbud's annual revenue requirement through a rider until OG&E's next rate case is completed and new rates are implemented. Redbud's revenue requirement includes the full investment or purchase price, return on and amortization of transaction costs, O&M expenses, depreciation and ad valorem taxes related to the plant.

[26] 2007 Long-Term Reliability Assessment, 2007-2016. NERC. October, 2007

Q. Do you believe that the Company's proposed ratemaking treatment regarding Redbud is appropriate?

A. Yes. As discussed by Mr. Hatfield, a critical component of the regulatory compact between a regulated utility and its customers is the opportunity for the utility to both recover prudently incurred costs and "to earn a fair return" on prudent utility investments. As described earlier in my testimony, I believe that the acquisition of Redbud is prudent and, accordingly, its costs, including both the return of and return on capital invested, should be recovered by the Company. The Company's proposed rider, followed by permanent rate recovery, will provide OG&E with the necessary opportunity to recover its costs.

Q. Is the Company's proposed ratemaking treatment regarding Redbud consistent with other ratemaking mechanisms?

A. Yes. As discussed by Mr. Hatfield, the Commission has adopted riders to ensure the opportunity for appropriate, and appropriately timely, cost recovery. Further, the recovery of transaction-related expenses is common in other jurisdictions. In numerous cases where a utility sold an asset which was formerly in rate base, transaction-related expenses were recovered by the utility.

Q. Do you concur with Mr. Hatfield that the business risk for OG&E increases when it is not allowed to recover material investments through rates?

A. Yes. The regulatory environment and expected outcomes from rate related requests is a major risk factor considered by investment analysts. Deviations from expectations, or even heightened risk of such deviations, can affect investment and ratings outlooks. To this point, Moody's Investor Services ("Moody's") wrote in a report published in August 2007 that the potential for contentious regulatory environments faced by utilities was one of its noted "storm clouds gathering on the horizon." Specifically, Moody's stated:

> Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more frequent requests for rate relief could create pressure for future incremental rate relief from state regulators, or at a minimum, raise the uncertainty level

> associated with expected recoveries — thereby directly affecting one of our primary rating drivers.[27]

Fitch Ratings ("Fitch") listed the, "legal framework and regulatory and political environment at the state level," as one of the main constituents of its comparative operating risk analyses for regulated utilities.[28]

I concur with Mr. Hatfield that when material investments and related operating expenses are not allowed recovery through rates, the ratings agencies and financial community attribute a greater degree of business risk to the utility which in turn negatively impacts customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

[27] Moody's Investors Services, *Special Report: Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector*, August 2007.

[28] Fitch Ratings, *U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines*, August 22, 2007.

Schedule JJR-1 (a)

Discount Rate Valuation Sensitivities

	Discount Rate (AT WACC)	Plant Valuation ($/kw)	Total Plant Value ($MMs)
OG&E WACC (AT)	**7.62%**	**$837.2**	**$1,029.8**
	8.00%	$792.0	$974.1
	8.50%	$737.4	$907.0
Base WACC (AT)	**8.80%**	**$711.9**	**$875.6**
	9.00%	$687.8	$846.0
	9.50%	$642.7	$790.5

Schedule JJR-1 (b)

Capacity Value Valuation Sensitivities

	Capacity Payments	Plant Valuation ($/kw)	Total Plant Value ($MMs)
	-10.00%	$638.2	$785.0
	-5.00%	$675.0	$830.3
Base Capacity Value	**Base**	**$711.9**	**$875.6**
	5.00%	$748.6	$920.8
	10.00%	$785.4	$966.1

Schedule JJR-1 (c)

Energy Margin* Valuation Sensitivities

	Fuel Cost Change	Plant Valuation ($/kw)	Total Plant Value ($MMs)
	-4.00%	$755.5	$929.3
	-2.00%	$733.7	$902.5
Base Energy Margin	**Base**	**$711.9**	**$875.6**
	2.00%	$690.0	$848.7
	4.00%	$668.1	$821.8

* Assumes market power costs are unchanged. Large changes in fuel costs would likely change market power costs as well.

Schedule JJR-1 (d)

Operating Cost Valuation Sensitivities

	Operating Cost Change	Plant Valuation ($/kw)	Total Plant Value ($MMs)
	-10.00%	$730.1	$898.0
	-5.00%	$721.0	$886.8
Base Operating Costs	**Base**	**$711.9**	**$875.6**
	5.00%	$702.7	$864.3
	10.00%	$693.6	$853.1

Operating Cost Valuation Sensitivities

	Operating Cost Change	Plant Valuation ($/kw)	Total Plant Value ($MMs)
	-10.00%	$730.1	$898.0
	-5.00%	$721.0	$886.8
Base Operating Costs	**Base**	**$711.9**	**$875.6**
	5.00%	$702.7	$864.3
	10.00%	$693.6	$853.1

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 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 125 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 CEA 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 20 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 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

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

Resource Procurement, Contracting and Analysis

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

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

Strategic Planning and Utility Restructuring

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

PROFESSIONAL HISTORY

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

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

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

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

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

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

EDUCATION AND CERTIFICATION

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

BOARDS OF DIRECTORS (PAST AND PRESENT)

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

AFFILIATIONS

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

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	2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Rate Case Analysis Cost of Service
Colonial Gas, Providence Gas	7/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	8/93	Algonquin Gas Transmission	RP93-14 – Rebuttal	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	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates
Tennessee GSR Group	1/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
Pacific Gas Transmission	2/95	Pacific Gas Transmission	RP94-149-000	Rate Design
Tennessee GSR Customer Group	3/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
ProGas and Texas Eastern	1/96	Tennessee Gas Pipeline Company	RP93-151	Declaration
PG&E and SoCal Gas	96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04	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	
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 07____-EI	Need for new nuclear plant
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
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	Public Benefits
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Public Benefits
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Public Benefits
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Public Benefits
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Public Benefits
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 (Direct)
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	Review Integrated Resource Management Filing
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 – Direct
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	Regulatory Issues
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
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
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	Industry Norms and 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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH3-93	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	Segmented Service
Brunswick Pipeline	9/06	Brunswick Pipeline	GH-1-2006	Market Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
TransCanada Pipelines Ltd.	3/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70
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
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Evaluate their use of storage
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
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	Tariff Changes

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Service - Direct
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Rate Filing Package; Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Texas Railroad Commission				
Southern Union Gas	5/85	Southern Union Gas Company	G.U.D. 1891	Cost of Service
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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	Tariff Filing
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/00	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
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

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American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern	Arbitration Panel	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
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
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 Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation

U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
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	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
District of Columbia Court City Council				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring