158

FILE

DUKE ENERGY OHIO EXHIBIT_____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Modify Rider PSR.	)))	Case No. 17-872-EL-RDR
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Amend Rider PSR.	)))	Case No. 17-873-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-874-EL-AAM

DIRECT TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

DUKE ENERGY OHIO, INC.

MARCH 31, 2017

PUBLIC VERSION

2017 MAR 31 PM 4: 33

PUCO

TABLE OF CONTENTS

Page

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Judah L. Rose. I am an Executive Director of ICF. My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, AND EMPLOYMENT EXPERIENCE.

A. After receiving a degree in economics from the Massachusetts Institute of Technology and a Master's Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I have worked at ICF for nearly 35 years. I am Chair of ICF's Energy Advisory and Solutions practice. I have also served as a member of the Board of Directors of ICF International and am one of three people among ICF's roster of 5,000 professionals to have received ICF's honorary title of Distinguished Consultant.

Q. WHAT IS ICF INTERNATIONAL?

A. ICF (NASDAQ:ICFI) has revenues over a billion dollars per year, approximately 5,000 employees and provides professional services and technology solutions across 13 market areas. Approximately 2,000 work in the areas of energy and environment. Our advisory and implementation services assist clients in strategy and policy analysis, program management, project evaluation, and other services. Our energy practice employs top experts who use an integrated approach to energy markets, applying cutting-edge technical skills and proprietary modeling tools to provide clients with a complete picture of the energy landscape—from electric power to fuels to renewables.

Q. WHO ARE ICF'S CLIENTS?

A. In the power and energy space, ICF's clients cover the full spectrum of possible clients including: utilities, government agencies, Independent Power Producers (IPPs), law firms, financial investors such as private equity firms, consumers, industry associations (e.g. EEI), environmental interest groups and Regional Transmission Organizations (RTOs) and Independent System Operators (ISO).

In the utility sector, for over 40 years, ICF worked with nearly all major United States and Canadian electric utilities. For example, ICF implements approximately 150 energy efficiency programs for 50 utilities. In addition, ICF has provided forecasts and other consulting services to major United States and Canadian electric utilities. In the U.S., ICF has worked on planning and forecasting issues with utilities such as AES, American Electric Power, Allegheny, Arizona Power Service, Dominion Power, Delmarva Power & Light, Dominion, Duke Energy, FirstEnergy, Entergy, Exelon, Florida Power & Light, Long Island Power Authority, National Grid, Northeast Utilities, Southern California Edison, Sempra, PacifiCorp, Pacific Gas and Electric, Public Service Electric and Gas, PEPCo, Public Service of New Mexico, Nevada Power and Tucson Electric.

In the government sector, ICF has been the principal power consultant to the U.S. Environmental Protection Agency ("EPA") for over 40 years, specializing in the analysis and computer modeling of air emission programs, especially cap and trade programs, and their impacts on the power, coal and other energy industries. We also have worked with the Federal Energy Regulatory Commission ("FERC") on transmission issues and the U.S. Department of Energy ("DOE") on energy security. In addition, we have worked with state regulators and energy agencies, including those in California, Connecticut, Kentucky, New Jersey, New York, Ohio, Texas, and Michigan, as well as with numerous foreign governments.

ICF's works with RTOs includes the Mid-Continent Independent Transmission System Operator ("Midwest ISO"), the Electric Reliability Council of Texas, the Western Electric Coordinating Council, West Connect, and the Florida Regional Coordinating Council.

Q. WHAT TYPE OF WORK DO YOU TYPICALLY PERFORM?

A. I have extensive experience in assessing wholesale electric power markets and regulation. This includes forecasting wholesale electricity prices, power plant operations and revenues, transmission flows, and fuel prices (e.g., coal, natural gas). I also have extensive experience in assessing environmental regulations and their impacts on supply and demand conditions in wholesale power markets, as well as on valuing individual power plants in the context of projected market conditions. My work usually involves ICF's models, databases, and forecasting, which are widely accepted and used by the energy industry and government agencies.

Q. WHAT EXPERIENCE DO YOU HAVE IN PROVIDING EXPERT TESTIMONY RELATING TO THE POWER SECTOR?

A. I have testified as an expert over 130 times in approximately 45 venues. I have testified before or made presentations to the FERC, an international arbitration tribunal, federal courts, arbitration panels, and before state regulators and legislators in 24 U.S. states and Canadian provinces: Arizona, Arkansas, California, Connecticut, Florida, Indiana, Kentucky, Louisiana, Manitoba, Massachusetts, Minnesota, Missouri, Nevada, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Quebec, Rhode Island, South Carolina, Texas, and West Virginia. I have testified extensively on electric power prices and markets, power purchase agreements, utility planning, and the development and acquisition of new generation resources and transmission. This work also usually involves ICF's models, databases, and forecasting. In addition, I have authored numerous articles in industry journals and spoken at scores of industry conferences. For specific details, please see my resume, attached hereto as Attachment 1.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THE STATE OF OHIO?

A. Yes. I have testified in Ohio many times. *See* Attachment 1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Duke Energy Ohio.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide economic forecasts for Ohio Valley Electric Corporation's (OVEC's)[1] two coal-fired powerplants, Clifty Creek and Kyger Creek, related to the request of Duke Energy Ohio to adjust Rider PSR.

Q. PLEASE DESCRIBE OVEC'S COAL POWERPLANTS.

A. Clifty Creek is located in Madison, Indiana, approximately 75 miles west of Cincinnati, and Kyger Creek is located in Cheshire, Ohio, approximately 160 miles east of Cincinnati. The generation capacity of Clifty Creek is a nominal 1,200 MW and the generation capacity of Kyger Creek is a nominal 990 MW – i.e. Clifty Creek is 21% bigger, and the sum of the two is 2,190 MW. Clifty Creek's 6 units came on line between 1955 and 1956, and Kyger Creek's 5 units came on line during 1955. However, they are highly controlled for air emissions. In 2011, the owners retrofitted the plants with Flue Gas Desulfurization (FGD or SO_2 scrubbers), and in 2003, Selective Catalytic Reduction (SCR or NO_x scrubbers).

Q. WHAT ARE THEIR COAL SUPPLY OPTIONS?

A. These powerplants have an excellent location for accessing coal supply. The plants are located on the Ohio River, and can access coal via barge from both the Northern and Central Appalachian coal production areas (covering parts of Ohio, Pennsylvania, West Virginia and eastern Kentucky) and the Illinois Basin (covering parts of Illinois, Indiana and western Kentucky). The plants can also

[1] For simplicity, I am not addressing the subsidiaries of OVEC.

access western Powder River Basis coal. As noted, they are also highly controlled for SO_2 emissions, and hence, can access and use a very wide range of coal types including high sulfur coal.

Q. WHO OWNS OVEC?

A. OVEC is headquartered in Piketon, Ohio and the following entities, some of which are subsidiaries of the same holding company, own stock in it: (1) Allegheny Energy, Inc.; (2) American Electric Power Company, Inc.; (3) Buckeye Power Generating, L.L.C.; (4) Dayton Power and Light Company; (5) Duke Energy Ohio; (6) Kentucky Utilities Company; (7) Louisville Gas and Electric Company; (8) Ohio Edison Company; (9) Ohio Power Company; (10) Peninsula Generation Cooperative; (11) Southern Indiana Gas and Electric Company; and (12) and The Toledo Edison Company.

The two plants are the main assets of OVEC. Duke Energy Ohio has a 9 percent equity interest in OVEC. Additionally, Duke Energy Ohio is a counterparty to, and sponsoring company[2] of, the Inter-Company Power Agreement (ICPA) pursuant to which its power participation ratio is 9 percent. Hence, Duke Energy Ohio is entitled to 108 MW from Clifty Creek and 89 MW of Kyger Creek for a total of 197 MW. Over the 2012 to 2016 period, average generation from the 197 MW was 0.93 million MWh. This roughly equal to 5% of Duke Energy Ohio

[2] Allegheny Energy Supply Company LLC, Appalachian Power Company, Buckeye Power Generating LLC, The Dayton Power and Light Company, Duke Energy Ohio Inc., FirstEnergy Solutions Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company comprise of the sponsoring companies.

retail sales, and hence, is a small fraction of the generation supply of Duke Energy Ohio's customers. Thus, the hedge contract is modest in size.

Q. HOW IS THE STRUCTURE OF OVEC UNIQUE IN OHIO?

A. The structure is more complex than for any powerplant in Ohio by a wide margin. The 12 owners of OVEC is much higher number than for any other power plant[3]. The owner are very diverse. The owners include Investor-Owned Utilities and Cooperatives. The owners include participants and non-participants in regional markets. The owners participating in regional markets and organizations participate in different regional markets and organizations. For example, some are located in PJM and MISO, and others are not located in any RTO or ISO market. These owners face very different business and regulatory environments as some are deregulated, others are traditionally regulated, and others still are cooperatives. This complicates decision making as the disparate cost recovery mechanisms create differing incentives for how to operate the plants. This diversity and complexity are also reflected in the fact that the sponsoring companies serve end-users in eight states: Ohio, Indiana, Kentucky, Maryland, Michigan, Pennsylvania, Virginia and West Virginia. Finally, I have not reviewed the matter in detail, but my understanding is that most decisions and changes to the contract requires unanimous consent. This is a very unconventional arrangement which greatly complicates decision making.

---

[3] There are 12 owners of OVEC, as noted above. But there are 13 sponsoring companies and there is not absolute symmetry between owners and co-sponsors. Hence, ownership is complex, and unusual.

Q. WHAT IS THE UNIQUE ORIGIN OF OVEC?

A. OVEC's origin is critical to understanding how such an unusual arrangement arose. OVEC was organized in 1952 to provide power for a large uranium enrichment facility then already under construction in Portsmouth, Ohio by the Atomic Energy Commission (AEC). The AEC, and its successors, acted quickly to supply urgently needed enriched uranium to the Department of Defense during the height of the Cold War. In 1952, OVEC entered into the DOE Power Agreement to supply power to the facility. In 1953, OVEC entered into the ICPA to support the DOE Power Agreement. In 2003, OVEC stopped providing power to the DOE, after the DOE terminated the Power Agreement. In 2011, OVEC and the sponsoring companies amended the ICPA through June 30, 2040. Thus, OVEC is a legacy of a pre-deregulation past era. Overall, the OVEC situation has been recognized as "different".[4]

Q. WHAT SPECIFIC FORECASTS ARE YOU PROVIDING?

A. I provide forecasts for the following key parameters for the two powerplants: (1) wholesale market electricity prices (firm, electrical energy and capacity), (2) utilization rates (i.e., capacity factors), (3) revenues, (4) gross margins (revenues less short run variable costs which are primarily the costs of the coal and secondarily variable non-fuel Operation and Maintenance (O&M) and emission allowance costs), and (5) net margins (gross margins minus demand charges;

---

[4] See *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, Case No. 14-1693-EL-RDR, Second Entry on Rehearing, Concurring Opinion of Chairman Haque at page 6, November 3, 2016.

demand charges have two components (i) fixed cash going forward costs such as fixed annual O&M, property taxes, General and Administrative (G&A)), and (ii) recovery of and on already spent capital costs.

The plants can sell into two key wholesale electricity markets for operated by PJM: PJM's electrical energy and capacity markets. The plants also sell PJM's ancillary service markets and while I also provide forecasts for these sales revenues, they are much smaller than energy and capacity revenues. PJM operates the wholesale transmission grid, and FERC regulated wholesale markets. Not all electricity is sold into the PJM markets. For example, some is used to supply utility load.

My testimony focuses on the two key wholesale power market prices relevant to the OVEC plants, namely PJM's AEP Dayton Hub price which is an average of electrical energy prices for select locations in Ohio, and PJM's capacity prices for the "RTO" capacity zone. I also modeled every node in the Eastern Interconnect, the world's largest interconnected grid, and therefore, I also provides forecasts for prices at the specific OVEC plant nodes. The plant revenues reflect nodal prices, but because hedging takes place at the Hub price, and the node and Hub prices are fairly similar, I focus on the Hub price.

I present my forecasts for April 1, 2017 to June 30, 2040 when the ICPA expires. However, forecasts are also annual and sub-annual.

Lastly, my testimony briefly discusses the issue of annual price volatility, and the relationship between my year-by-year price forecasts and annual price volatility.

Q. HOW IS YOUR SUMMARY ORGANIZED?

A. My summary has four main parts:

- **Approach**
- **PJM Market Price Forecast** – Firm Electricity, Electrical Energy, Capacity Prices and Annual Price Volatility
- **Plant Specific Forecasts** – Dispatch, Revenues, Gross Margins, Demand Charges, Net Margins, and Annual Cost Volatility
- **Conclusions**

I.1 Approach

Q. PLEASE SUMMARIZE YOUR APPROACH.

A. My approach has three parts. First, I compare the costs of power from Clifty Creek and Kyger Creek with the costs of purchasing power from the market under Base Case conditions. I base my recommendations on the operations of Clifty Creek and Kyger Creek on the cash going forward economics which exclude sunk costs. I also do the comparison including sunk costs. I do not opine on the treatment of sunk costs in terms of recoverability, though I present perspectives on their treatment.

Second, I compare the annual volatility of the costs of the two procurement approaches basing the comparison on recent historical data. I do not opine on what if any trade-offs should be made between cost and volatility to the extent the results indicate there is a trade-off, though I do believe expected costs and cost volatility are both appropriate considerations.

Third, I consider three sensitivity scenarios: (1) using the Energy Information Administration's (EIA) natural gas price reference case forecast, (2) using hypothetically lower annual cash going forward costs for OVEC plant operation, and (3) assuming no expected national CO_2 control program even in the long term – i.e., even by 2040.

I.2 MARKET PRICE FORECASTS

Q. WHAT IS YOUR FIRM ALL HOURS POWER PRICE FORECAST?

A. I project that firm all-hours wholesale power market prices for the AEP Dayton Hub will increase significantly relative to 2016 levels. Firm power prices have two components, electrical energy and capacity[5]. The 2017 – 2040 average firm all hours electricity price will be [BEGIN CONFIDENTIAL] [redacted] [redacted][6]. [END

[5] The capacity price is averaged across the 8760 hours of the year and added to the all-hours average electrical energy price. The result is a single $/MWh price often referred to as a unit contingent firm price or a bundled price.

[redacted]

CONFIDENTIAL] My forecast is of the yearly (and sub-yearly) expected value (i.e., probability weighted average) which assumes average weather.

I also conclude that 2016 prices are not useful indicators of future prices, especially long-term average future prices. This conclusion about 2016 is based on several considerations:

- **Extreme Conditions** - The winter of 2015/2016 was the warmest in US history, and oil prices fell from $108/barrel in early 2014 to less than $30/Barrel in early 2016.
- **Historically Low Prices** - AEP Dayton electrical energy prices were the lowest since 2005, and Henry Hub gas prices were the lowest since 1999. Dominion South gas prices were the lowest ever.
- **Evidence of Non-sustainability** – Between 2014 and 2016, US drilling for oil and gas dropped 75% and there were over 100 bankruptcies in mid and small oil and gas producers.
- **Price Increases During 2016** – Many spot and forward prices increased over the course of 2016 though some fell back in the face of another bout of record warm weather in early 2017.
- **Modeling** - Computer model simulations capturing the long-term dynamics of the power and related industries support higher prices. This modeling also accounts for general inflation, long-term conditions including regulatory changes, etc.

Even in the near term, firm all-hours power prices are higher than 2016. The 2017 - 2026 average firm all hours price will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Q. WHAT IS YOUR ELECTRICAL ENERGY PRICE FORECAST?

A. Electrical energy is the larger of the two components of firm wholesale electricity prices. PJM purchases and OVEC sells electrical energy hourly and sub hourly and prices are expressed in $/MWh. I project that 2017 to 2040 all hours electrical energy prices will increase from 2016 levels [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The key drivers of higher electrical energy prices over time include higher natural gas prices, and higher energy demand as weather returns to average conditions, load growth and retirements, new unit costs and general inflation. In the long run, electrical energy prices also increase due to national CO_2 regulations. This impact is not significant until 2030.

Even in the near term, all-hours electrical energy prices increase above. The 2017 - 2026 all hours price will average [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Q. WHAT IS YOUR CAPACITY PRICE FORECAST?

A. PJM purchases and OVEC can sell capacity three years forward and the price is expressed as \$/MW-day, \$/kW-month and \$/kW-year. I forecast that [BEGIN CONFIDENTIAL] [redacted].[7] [END CONFIDENTIAL] PJM already purchased capacity through May 31, 2020, and will purchase again May 2017 for delivery in 2020-2021. One benchmark for capacity prices is the net Cost of New Entry (CONE), and another is CONE times the Balancing Ratio (typically 78 to 90% times CONE) which is the maximum safe harbor bid price and designed to be the indifference point between providing energy only or entering into capacity agreement and then providing firm energy subject to penalties. I project the average PJM RTO capacity price will [BEGIN CONFIDENTIAL] [redacted] Disaggregating into already auctioned capacity and non-auctioned capacity sales periods, [redacted] [END CONFIDENTIAL]

[redacted]

The key drivers of higher capacity prices include: the elimination of excess capacity due to retirements and electricity demand growth, less depression of capacity prices by Demand Resources (DR) as PJM starts to purchase 100% of its needs as capacity performance product and fully eliminates procurement of lesser quality capacity referred to as Base Capacity, lower energy earnings for marginal new units as the system adds more new combined cycles, and gas price increases decrease utilization, and likely additional reforms to the PJM capacity market such as correction of the current inappropriately low penalty rates for capacity performance[8]. [BEGIN CONFIDENTIAL]. [redacted] [END CONFIDENTIAL].

Q. WHAT IS YOUR ESTIMATE OF ANNUAL WHOLESALE ELECTRICITY PRICE VOLATILITY?

A. Power prices have exhibited very significant annual volatility. I anticipate this significant annual price volatility will continue around the expected value. I focus on one measure of annual volatility namely the range of annual all hours electrical energy prices for the AEP Dayton Hub. Over the 2012-2016 five year period, the range was $27.8/MWh to $44.1/MWh or $16/MWh. This range is 48% of the average price, and hence, indicates high volatility. When I factor in capacity

[8] Subsequent to the June 9, 2015 FERC Order on capacity performance, PJM released data on the hours that would qualify for penalties back to 2005 (released November 16, 2015). This data strongly supports the view that PJM has overstated the expected hours of penalty, and hence, understated the penalty rate by a factor of approximately 2 to 10. This relationship occurs because the penalty in $/MWh is net CONE times balancing ratio divided by the expected hours of penalty – too high an expected hours estimate lowers the penalty rate. Lower penalties mean lower capacity prices – the alternative, energy-only supply, is less attractive, and hence, bidders have less opportunity cost for eschewing energy only and bidding to supply the PJM capacity performance product. In its June 9, 2015 Order, FERC has indicated that the PJM penalty rate is inadequately supported (PJM did not offer sufficient either historical data and offered no PJM grid modeling) and requires PJM to report on this issue this year.

prices, the firm price range over the same period was $31.6/MWh to $47.6/MWh and range was $16/MWh or 43% of the average. The high volatility is driven in large part by variation in weather conditions (weather was warm in the winters of 2012 and 2016 while the winters were cold in 2014 and 2015), the lack of storage, natural gas price volatility, variation in generation supply costs, industry cycles and changes in FERC regulations. Greater reliance on spot natural gas will increase spot power price volatility, especially in situations where natural gas production and delivery infrastructure falls behind increased natural gas consumption.

I.3 Powerplant Forecasts

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK DISPATCH?

A. Between 2017 and 2040, I forecast the average plant utilization rates will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The increase reflects increasing natural gas and electrical energy prices, the impact of retirements, growing demand, and the lack of new coal power plant construction.

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK REVENUES?

A. Over the 2017 to 2040 period, in nominal dollars, I forecast the average total revenues for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted].[9] [redacted].[10] [redacted] [END CONFIDENTIAL]

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK GROSS MARGINS?

A. Gross margin equals revenues less fuel and other short run variable costs including emission allowance costs. Over the 2017 to 2040, in nominal dollars, I forecast the average annual gross margins for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted].[11] [END CONFIDENTIAL] Revenues increase faster than costs and margins increase much faster than revenues – i.e. there is operating leverage.

Q. WHAT IS THE FORECAST OF OVEC DEMAND CHARGES?

A. OVEC demand charges are paid pursuant to the ICPA originally entered into in 1953. The demand charges are set in the same manner as cost recovery of a traditional rate base powerplant. The forecast of OVEC's projected demand charges was provided to me. Between 2017 and 2040, the total demand charge

---

[9] [redacted].

[10] [redacted]

[11] [redacted]

averages approximately [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

Q. HOW SHOULD SUNK COSTS BE TREATED?

A. Society's economic value[12] is maximized by maximizing the cash going forward net margins and treating previously incurred capital investment as sunk – i.e., by not including sunk costs. My economic analysis excluding sunk costs concludes that OVEC should continue to operate of its power plants.

Duke Energy Ohio is requesting recovery of all costs, including sunk costs, via Rider PSR. I note that this request may be appropriate in spite of the complexities of OVEC's situation, notably the plants are not owned by or rate based by Duke Energy Ohio but are rather subject to a long term power agreement under which Duke Energy Ohio has little control of OVEC. It is my understanding that the specific contract was undertaken long ago (though amended in 2004 and 2011) and well before deregulation of any power markets. The diversity of the players and regulatory frameworks and the regional scope of the situation does not lend itself to easily changing the contract or establishing a policy regarding the future of the plants. This arrangement is consistent with this situation being a legacy of a former era in which the form was secondary to the intent which was to urgently support reliable production of enriched uranium in the early 1950s. While the

[12] Assuming efficient pricing.

form of the arrangement is contractual, it may have been the original intent to treat the Department of Defense similar to or better than other firm customers and treat the plants in a manner similar to jointly owned, rate base powerplants – i.e. similar to other powerplants approved and included in the rate base. Evidence for this is that the payments are determined the same way traditionally regulated costs are determined. This argues for recovery of costs including sunk costs because they were prudently incurred.

Notwithstanding the above, I have not conducted a detailed history of the contract, the plant's regulation, and am not opining on how the sunk costs should be treated with regard to rate recovery. I also acknowledge that this is a different, complex and unique situation. Accordingly, I also report the results based on the total demand charge including recovery of sunk capital.

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING CASH GOING FORWARD COSTS?

A. Net margins are positive on a present value basis. This means on a cash going forward basis, the plants power is expected to cost less than relying on the market. In addition, the plants' power costs have less volatility than market purchases and the power supply from the plant provides a hedge against higher prices. Thus, the plant should continue to operate. In the Base Case, the present value of the plant's [BEGIN CONFIDENTIAL] [redacted]

[redacted][13] [redacted]

[redacted] [END CONFIDENTIAL] Thus, the contract is a very modest sized hedge contract for the load with an expected cash going forward savings.

In Exhibit 1, we shown the net present value of pre-tax net margins across the Base and four different sensitivity cases with and without considerations of sunk costs.

- **Base Case**: is ICF's expected view based on expected values for key input assumptions such as natural gas prices, coal prices, national CO_2 regulations and PJM demand.
- **No National CO_2 Regulations Case**: is the same as the Base Case with the exception of no national CO_2 regulations, and that natural gas prices are adjusted by this impact.

[13] This is pre-tax calculation. This assumed discount rate equals 6.5%.

- **"Hypothetical" Lower OVEC Fixed Costs Case**: is the same as the Base Case expect OVEC's estimated costs are adjusted downwards to illustrate sensitivity to this parameter.
- **AEO 2017 Base Case**: is the same as the Base Case with the exception of Henry Hub gas price projections; this case uses the EIA Annual Energy Outlook (AEO) 2017 Reference Case forecast [14]. This forecast price is higher than ICF's and hence if used increases savings.
- **Combination of All Three Sensitivities Case:** is the same as the Base Case except for changes in the three sensitivity cases listed above, where the gas prices are from EIA AEO 2017 Reference Case, costs reflect a hypothetically lower level, and no national CO_2 regulations are considered.

[14] US EIA's "*Annual Energy Outlook 2017.*"

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

Source: ICF projections with supplementary data from AEO 2017, FERC Form 1, and OVEC

[END CONFIDENTIAL]

Q. WHAT IS YOUR ASSESSENT OF THE PLANT'S ANNUAL COST VOLATILITY?

A. Annual wholesale market price volatility is much higher than volatility in the costs of Clifty Creek and Kyger Creek. The range of average delivered coal cost over the 2012 to 2016 was $2.0/MMBtu to $2.5/MMBtu or $0.4/MMBtu. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

I.4 Conclusions

Q. WHAT ARE YOUR CONCLUSIONS?

A. My conclusions address electricity market price forecasts, powerplant operational and financial performance forecasts, demand charges and net margins, and annual market power price and annual cost volatility.

I.4.1 Electricity Market Prices

I conclude that firm all-hours wholesale electricity prices are on an upward trajectory relative to 2016 prices. Between 2018 and 2039, in the Base Case, firm prices increase by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] This forecast is supported by: (1) unsustainably extreme conditions in 2016, (2) minimal or very energy low price levels that are ripe for recovery, (3) industry evidence that the low prices cannot be sustained, (4) large increases in prices over the course of 2016 until a bout of warm weather in early 2017, and (5) detailed computer simulations of the industry that are conservative in terms of natural gas prices relative to the US EIA's gas price forecast.

<u>Powerplant Operational and Financial Performance</u>

Gross margins increase over time because market energy prices rise, and capacity prices increase. This forecast reflects two recent regulatory developments favorable to the economics of Clifty Creek and Kyger Creek. First, it is now very likely that potential national CO_2 emission and other environmental regulations adverse to OVEC's plants will be significantly deferred compared to national CO_2 controls starting in 2022 as per the Clean Power Plan (CPP). Second, PJM is implementing capacity market reforms related to the PJM capacity market order in 2015. This increases gross and net margins relative to a non-reformed capacity market in a CPP regulated situation.

[BEGIN CONFIDENTIAL] The OVEC [redacted] [END CONFIDENTIAL] This is in part because they access low cost coal from the Ohio River, while the market increasingly relies on higher cost sources of power. This occurs starting in 2019 when the market recovers from 2016 depressed levels. This conclusion becomes stronger if any of three things occur – lower costs, US EIA gas price forecasts, which are higher than ICF's, turn out to be more accurate, or if national CO_2 regulations, already assumed to be delayed by recent developments never occur during the forecast period.

Price and Cost Volatility

[BEGIN CONFIDENTIAL] [redacted] END CONFIDENTIAL] I expect this relationship to continue. Natural gas is one of the most volatile commodities and partly sets market prices while the coal and fixed costs of Clifty Creek and Kyger Creek are much less volatile. Lower volatility all else equal is preferred, and additional supports continued operation of OVEC power plants, but I do not opine on the trade-offs between the two, to the extent they would exist.

I have not conducted a detailed history of the contract, OVEC's complex regulatory history, and am not opining on how sunk costs should be treated with regard to rate recovery. However, I note there are strong arguments in support of Duke Energy Ohio's request. The unconventional and unique power supply agreement is the legacy of prudent decisions made long before deregulation. Indeed, it is my understanding that the decision was primarily a response to an

---

[redacted]

urgent national need for the industry to work collaboratively on an important matter of national defense.

II. DESCRIPTION OF THE WHOLESALE ELECTRICITY MARKET

Q. WHAT ARE THE PRODUCTS IN PJM'S WHOLESALE ELECTRICITY MARKETS?

A. PJM operates wholesale electricity markets including: (1) electrical energy markets with prices in $/MWh, (2) capacity markets with prices in $/kW-year, $/kW-month or $/MW day, and (3) ancillary service markets.

Q. HOW ARE GENERATORS COMPENSATED FOR ENERGY COSTS?

A. PJM generators bid into the PJM run electrical energy markets, i.e., the PJM Day-Ahead or Hourly energy markets (i.e. balancing or real time); plants receiving capacity payments from PJM must bid into the Day-Ahead markets. The markets employ a pricing algorithm known as Locational Marginal Pricing (LMP) that sets prices node by node based on the marginal bid in each time interval, node by node congestion impacts, and node by node contribution to energy losses. ICF's modeling employs this same node by node algorithm, and employs it across the entire Eastern Interconnect, the world's large interconnected grid[16]. The pricing is designed to compensate all participants for at least their bid price for providing electrical energy.

---

[16] The US is split into three grids – the Eastern Interconnect, the WECC (covering the western states from the Front Range of the Rocky Mountains to the Pacific Ocean), and ERCOT (covering most of Texas). The Eastern Interconnect includes Ontario and the Canadian Maritimes.

Q. WHAT ARE CAPACITY MARKETS?

A. PJM runs a capacity market to ensure enough capacity is reserve in advance to maintain reliability. The payments for capacity supplement the electrical energy market's revenues so that no entity does not want to accept the obligation to be on line and ready to provide electrical energy. This supplemental payment is made in part because in its deregulated electrical energy markets, generator bids are usually constrained to bid short-run variable costs. Hence, some existing units may not be able to cover their cash going forward fixed costs (e.g., property taxes, annual labor, SG&A, OEM upgrade fees) when prices cannot exceed plants' variable costs, rendering them uneconomic to continue to operate even though they are needed for maintaining reliability. Furthermore, new units required for reliability may not earn sufficient recovery on and of capital[17]. In theory, the capacity market enables generators to recover their incremental net going-forward fixed costs and enables grid operators to maintain an adequate level of planning reserves. It therefore provides supplemental revenue to cover the going-forward costs of marginal sources. As power plant earnings in the energy markets increase, capacity prices generally tend to decrease, and vice versa.

Q. HOW ARE GENERATORS COMPENSATED FOR CAPACITY COSTS?

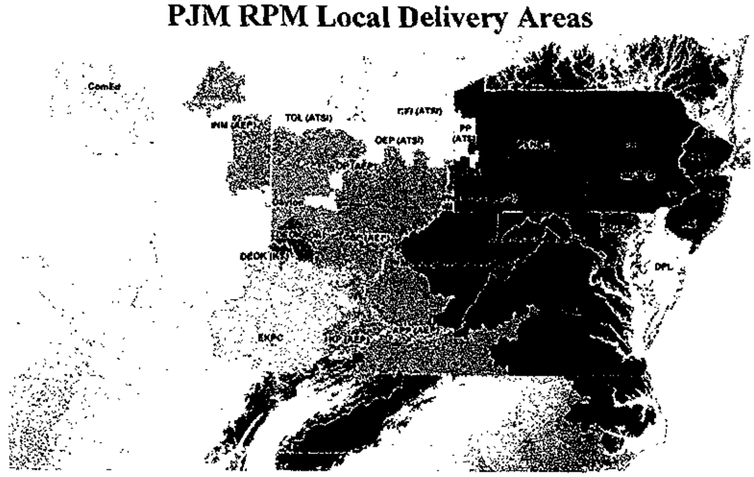
A. In Ohio, generators are compensated for capacity costs by participating in the PJM Reliability Pricing Model ("RPM") process, which includes self-supply, bilateral contracts, and most importantly, PJM run auctions such as the Base

---

[17] Recovery of and on capital invested in existing plants is not considered a going forward cost.

Residual Auction ("BRA") process. A map of PJM's RPM Local Delivery Areas ("LDAs") is shown in Exhibit 3. Though not shown, the "RTO" delivery area covers those LDAs which do not break out at separate clearing prices in the BRA auction process. Clifty Creek and Kyger Creek have always been in the RTO capacity pricing region. Exhibit 4 shows the results of the May 2016 auction and the areas with differentiated prices; starting in the May 2017 BRA for 2020-2021 delivery the Base product is discontinued. PJM is the largest RTO in terms of demand served in the US and has the nation's largest capacity market.

Exhibit 3
PJM RPM Local Delivery Areas



Source: PJM ISO

Exhibit 4
PJM RPM Capacity Prices – BRA May 2016

	Capacity Performance		**Base Generation**	
	$/kW-yr	**$/MW-day**	**$/kW-yr**	**$/MW-day**
Rest of RTO	$36.50	$100.00	$29.20	$80.00
EMAAC	$43.72	$119.77	$36.42	$99.77
PEPCO	$36.50	$100.00	$29.20	$80.00
COMED	$74.01	$202.77	$66.71	$182.77
BGE	$36.61	$100.30	$29.31	$80.30

Source: PJM

Q. ARE THERE ALTERNATIVES TO SELLING CAPACITY IN THE PJM BRA CAPACITY AUCTION?

A. Yes. One alternative is to sell capacity into one of the three reconfiguration "incremental" auctions held closer to the start of the delivery year. Another is to sell capacity to buyers outside PJM. A third was to sell capacity in the capacity performance transition incremental auctions that were held in 2015 to procure capacity performance resources for 2016/2017 and 2017/2018 delivery years.[18] Incremental auctions were held because FERC significantly changed PJM capacity market rules in June 2015 and required incremental capacity. A fourth is to be an energy-only resource and receive capacity bonuses for performing during emergency hours. Nearly all capacity revenue thus far has been from the BRA. Among all the arrangements for receiving scarcity of capacity payments, the most complicated arrangement pertains to be energy-only resources. Energy-only resources do not sell forward capacity, but when penalties are collected from

[18] Source: http://www.pjm.com/~/media/documents/manuals/m18.ashx

plants with capacity obligations for failure to perform, the penalties are distributed to energy-only resources pro rata based on their capacity during emergency hours and to over performing capacity resources.

Q. WHY IS THE ENERGY-ONLY OPTION ESPECIALLY IMPORTANT?

A. The energy option was designed to stabilize and support capacity prices by creating an alternative, and hence, an opportunity cost for supplying capacity. The optimal bid is the minimum of net fixed costs (net of expected energy margin) and opportunity cost (revenues available from being energy only). The key to this system is the penalty rate (measured in $/MWh) which is set equal to the ratio of net CONE times balancing ratio divided by the hours of expected emergency. When the hours equal the expected level, the revenues available to energy only equals net CONE times balancing ratio. PJM has set the expected hours of expected emergency hours too high, and hence, the penalty rate is too low; indeed PJM set the expected hours at the maximum possible and hence the opportunity cost at the minimum possible. Thus, until this is fixed actual market pricing is not probative because it cannot be continued; there is no justification. Further, the energy-only option fails to provide the support expected; the expected support is referred to as the soft price floor and equals net CONE time balancing ratio (balancing ratio is typically 83% to 90%) or approximately $235/MW day. Specifically, in the original June 9, 2015 Order setting capacity market rules, PJM's proposal to use 30 hours was accepted but FERC instructed that PJM report on the 30 hours no later than 2017 since the basis was considered inadequate. Subsequently, PJM released long-term data indicating the long term average was not even close[19]. Our forecast is consistent with an eventual correction to this market shortcoming. While we expect more support for capacity prices once PJM solves this problem, and believe capacity price data cannot be used to predict future conditions until this critical problem is fixed, [redacted].

Q. HOW ARE GENERATORS COMPENSATED FOR THE COSTS OF PROVIDING ANCILLARY SERVICES?

A. Generators are compensated for ancillary services through either cost-based rates, or the PJM market. The principal payments are to powerplants acting as operating reserves which can be quickly deployed by system operators, and give up the opportunity to participate in the energy market. As noted, ancillary service revenues are a very small portion of total costs.

---

[19] http://www.pjm.com/~/media/committees-groups/committees/mrc/20160728/20160728-item-06-non-performance-assessment-charge-rate-calculation.ashx. This document points out that current penalty hours is "NOT" (capitals in original) adequately supported. The document also points out that the average of the RTO wide PAH in the last three years was 14 hours including the 30 hours in delivery year 2013-2014 that resulted primarily from January 2014, an outlier year. They do not conclude 14 hours is correct. The basis for the 30 hours was the 2013/2014 RTO average. As we now know, based on data released by PJM on November 16, 2015, and subsequent to the issuance of the capacity performance Order of FERC on June 9, 2015, this was the highest number recorded between 2005 and 2016. Therefore, PJM's choice resulted in the lowest possible penalty rate (the highest number possible in the denominator of a ratio results in the lowest possible value of the ratio given the numerator). To see how high the 30 hours is relative to the actual expected, consider the following alternative estimates available to PJM, and now available to the public: (1) the 2011/2012 to 2013/2014 average RTO hours was 12 hours, (2) the 2011/2012 to 2015/2016 average was 8.4 hours, and (3) the RTO average penalty hours between June 2005 and end of May 2016 was 34 or 3.1 per year which is one tenth the chosen level. As noted, this data became available November 16, 2016. Furthermore, even if one assumed every single PJM PAH was in the RTO region, even though only 20% were, there were 171 hours in PJM (RTO and sub-regions) over the last 11 years (i.e. between June 1, 2005 and May 31 2016 or 15 hours per year; this is still half the 30 chosen.

III. RECENT WHOLESALE POWER PRICING TRENDS

Q. WHAT WERE THE WHOLESALE PRICES FOR ENERGY FOR THE LAST 5 YEARS?

A. Exhibit 5 below provides wholesale electrical energy market prices for the period from 2012 to 2016.[20] Electrical energy prices are set node-by-node, but PJM reports load weighted zonal averages for demand nodes and hubs and simple averages for supply nodes. Between 2012 and 2016, AEP Dayton Hub all-hours electrical energy prices averaged $34.9/MWh in real 2016 dollars, and $33.9/MWh in nominal dollars. Historically, Clifty Creek and Kyger Creek nodal prices averaged 4.4% lower compared to AEP Dayton Hub's All-Hours prices. The range of prices was from $42/MWh in 2014 to $26.6/MWh in 2016 or $15.4/MWh – i.e., the lowest prices were in 2016. As noted, 2015/2016 winter weather was the warmest on record and electrical energy prices and natural gas prices were the lowest.

[20] Historical energy pricing data come from publicly available sources including Platts, SNL Financial and ICE data compilations. Capacity pricing data is publicly available through the PJM BRA results, available on the PJM website and through various news sources.

Exhibit 5
Historical Electrical Energy Prices – All-Hours ($/MWh)

Source	Year	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]
		(2016$/MWh)	(2016$/MWh)	(Nom$/MWh)	(Nom$/MWh)
Historical	2009	36.8	34.9	33.0	31.3
	2010	41.4	39.4	37.6	35.8
	2011	41.8	39.2	38.7	36.4
	2012	33.1	32.0	31.2	30.2
	2013	36.5	33.7	35.0	32.4
	2014	45.1	41.5	44.1	40.5
	2015	31.9	29.9	31.5	29.5
	2016	27.8	26.6	27.8	26.6
	2012-2016	**34.9**	**32.7**	**33.9**	**31.8**
	2009-2016	**36.8**	**34.7**	**34.9**	**32.8**

Source: SNL Financial
[1] The nodal prices for Clifty Creek and Kyger Creek from 2009 to 2015 represents OVEC node. PJM updated its LMP Bus Model on Dec 9, 2015 and added CLFTY and KYGER nodes. 2016 represents average of CLFTY and KYGER nodal prices. These are 8760 hour nodal averages.

Q. WHAT WERE THE WHOLESALE PRICES FOR CAPACITY FOR THE LAST 5 YEARS?

A. As mentioned above, PJM capacity prices are primarily established via a PJM operated auction for three-year forward capacity delivery for June 1 through May 31 of the following year. This is referred to as the Base Residual Auction (BRA). Thus, calendar year 2017 capacity prices reflect auction results in May 2013 for the period January 2016 - May 31, 2016, and in May 2014 for June 1- December 31. Exhibit 6 shows calendarized 2013 to May 31, 2020 capacity prices from PJM auctions. Over the last 5 years, capacity prices in the RTO sub-region of PJM averaged approximately $36.6/kW-yr in nominal dollars (approximately $100/MW day). As noted, none of the historic capacity prices reflect full implementation of the capacity performance arrangements. Even when PJM is

100% procuring capacity performance product in the forthcoming May 2017 auction, it will still be using the lowest possible penalty rate from the perspective of the number of hours of emergency; the penalty rate is too low, and hence, bids for the willingness to be exposed to the penalties are too low.

Exhibit 6
PJM Capacity Prices for the RTO Zone (Nom$/kW-yr)

RTO Capacity Prices (Nom$/kW-yr)				
Delivery Period	**Base Residual Auction**	**1st Incremental Auction**	**2nd Incremental Auction**	**3rd Incremental Auction**
2013	8.4	6.8	3.5	1.2
2014	31.0	4.2	6.4	6.0
2015	48.1	10.0	32.8	38.6
2016	33.3	19.3	27.3	25.9
2017	34.6	27.0	10.4	
2018	53.3	18.6		
2019	46.4			
Jan 2020-May 2020	15.2			
2013-2019 Average	**36.4**	**14.3**	**16.1**	**18.0**
2017-2019 Average	**44.8**	**22.8**	**10.4**	**NA**
2016-2020 Average	**36.6**	**NA**	**NA**	**NA**

Source: PJM

IV. MODELING APPROACH

Q. WHY IS A MODELING-BASED PRICE FORECAST FOR ENERGY AND CAPACITY NEEDED?

A. A forecast based on model projections is needed because the alternative (i.e., forwards for electrical energy) are not liquid after a one to two years and PJM BRA capacity prices are not available after May 31, 2020.

Q. HOW WAS THE ELECTRICAL ENERGY AND CAPACITY MARKET PRICE PROJECTION CREATED?

A. I used two models to develop wholesale power market prices: a licensed Promod model and ICF's proprietary IPM® Model. Promod was used for the first ten year forecast period for electrical energy prices. IPM® was used for capacity expansion and retirements, capacity prices, and coal prices, and CO_2 allowance prices. Both models forecast energy prices on an hourly basis, based on supply and demand fundamentals, and IPM was used for the long-term electrical energy and capacity forecasts.

Q. PLEASE DESCRIBE PROMOD.

A. Promod is a widely accepted and highly detailed model based on supply and demand fundamentals. Promod chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. Promod uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved alternating current (AC) load flow, to calculate the real power flows for each generation dispatch. This enables Promod to capture the economic penalties of re-dispatching generation to satisfy transmission line flow limits and security constraints.

A detailed treatment of transmission is especially required due to the large amount of coal power plant retirements west of the Appalachian Mountains. In the near-term, new units are being added: however, most are natural gas-fired plants located to the east of the Appalachian Mountains. With limited new builds west of the Appalachians, there is the potential for greater transmission congestion in Ohio and associated electricity price premiums than if new power plant construction were more broadly distributed.

Q. PLEASE DESCRIBE IPM®.

A. IPM® is a widely used and accepted forecasting model based on supply and demand fundamentals that forecasts hourly electrical energy prices. IPM® is also a dynamic model that optimizes capacity decisions over the entire planning period simultaneously. Over time, this becomes more important in the energy market, and is especially critical for forecasting capacity prices. Promod does not incorporate investment decision-making endogenously because of its very detailed treatment of transmission and nodal pricing.

IPM® captures a detailed representation of all electric boilers and generators in the North American power markets. The model uses a linear optimization to simultaneously solve for all years: power plant dispatch and fuel use, capacity expansion, environmental retrofitting, modernization/re-powering, inter-regional transmission, electric energy and capacity prices, fuel prices, and emissions costs. The model captures the performance characteristics and limitations of conventional and unconventional generation technologies including gas and steam turbines, combined cycle, co-generation, nuclear, hydro, wind, solar, and other renewables. Energy efficiency and demand side management programs are evaluated in an integrated framework with other resource options.

Q. WHAT ARE THE KEY INPUT PARAMETERS IN YOUR MARKET PRICE FORECAST?

A. The key assumptions are oil prices, natural gas prices, coal prices, electricity demand growth, environmental regulations, new thermal unit costs and performance and renewable assumptions. The next section of my testimony focuses on our oil and natural gas price forecast.

V. MODELING ASSUMPTIONS – OIL AND NATURAL GAS PRICES

V.1 Oil Prices

Q. WHAT ARE YOUR ASSUMPTIONS FOR OIL PRICES?

A. Oil prices moderately increase over time from current levels of roughly \$50/Barrel to approximately \$77/barrel by 2025 in real 2016\$ and \$92/barrel in nominal dollars. This is consistent with increasing oil and gas prices over time.

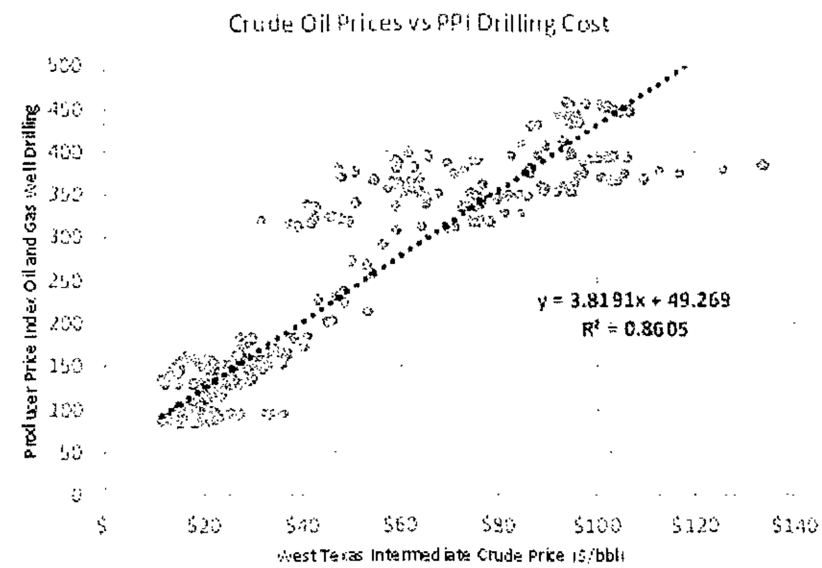
Q. WHY ARE OIL PRICES IMPORTANT?

A. While oil is rarely used in North America to generate electricity, natural gas prices can correlate with oil prices. For example, the decrease in gas prices in 2015 occurred even though the winter was the cold, in part because of the fall in oil prices which started in mid- 2014 and continued until early 2016. The exact relationship between these two hydrocarbons is complex and involves many factors, some of which increase correlation and some of which decrease correlation. Overall, the key is that our forecast assumes moderate increase in oil prices. However, if oil prices were unexpectedly higher, gas prices could also be higher. Therefore, volatility might propagate to consumers via their purchases of electricity, natural gas and oil products.

Q. WHY MIGHT OIL AND GAS PRICES CORRELATE?

A. One reason is the nearly one for one correlation between oil prices and drilling costs between 1986 and 2016 (see Exhibit 7). While the amount of drilling per unit gas is decreasing, drilling costs still correlate tightly with oil prices. Another reason for the linkage is that many of the macroeconomic factors which increase demand for oil, and commodities also increase demand for gas. As noted, this is a complicated situation with many factors involved, but we are currently in a period of lower oil prices, which is lowering drilling costs per unit of drilling activity.

Exhibit 7
Historical Relationship between Oil Prices and Drilling Costs



Source: www.eia.gov and http://www.bls.gov/ppi/#data

V.2 Natural Gas Prices

Q. WHAT IS THE SCOPE OF YOUR NATURAL GAS PRICE FORECAST?

A. The forecasts involves scores of natural gas prices that vary by location, year and season/month. This is because the gas and power modeling is integrated across either most of the North American power grid or all of North America depending on the model. However, the two key market prices are Henry Hub and Dominion South. Henry Hub is a location in Louisiana and it the delivery location for the NYMEX futures contract. This is the most commonly used marker gas price in the US. Many PJM gas fired powerplants pay Henry Hub plus a premium.

Dominion South is located northeast of Pittsburgh, and is a marker for Marcellus and Utica shale gas. While no PJM gas powerplant pays Dominion South, some pay Dominion South prices plus a premium or similar prices.

Q. WHY ARE NATURAL GAS PRICE FORECASTS IMPORTANT?

A. Natural gas prices are an important determinant of a portion of on-peak wholesale power prices in the AEP-Dayton Hub market and will be increasingly important over time as all new thermal capacity is projected to be natural gas-fired. However, in other hours, coal generation sets prices, particularly in the off-peak and the near-term. Also, when delivered gas prices are very high, it is because of colder than average weather, and hence, there is an amplification of the correlation as the power grid can also experience high demand, use of the less efficient powerplants and even shortages during these cold weather conditions.

Q. WHAT HAVE HENRY HUB NATURAL GAS PRICES BEEN HISTORICALLY?

A. Between 2000 and 2008 Henry Hub gas prices averaged \$6.03/MMBtu in nominal dollars and \$7.37/MMBtu in real 2016 dollars, and averaged in two years (i.e., 2005 and 2008) approximately \$10.53/MMBtu to \$9.97/MMBtu in 2016 dollars (see Exhibit 8). Since the great recession, which ended in 2009, Henry Hub prices have averaged \$3.54/MMBtu in nominal dollars and \$3.75/MMBtu in real 2016 dollars. Over the last five years, the average has been \$3.20/MMBtu in nominal dollars and \$3.29/MMBtu in real 2016 dollars. During this period, there were several periods of extremely warm winters, especially 2011/2012 and

2015/2016, several periods of colder weather, especially winters 2013/2014 and 2014/2015. 2016 gas prices are the lowest in the post 2000 period. Also, in the first half of this period (i.e. the first half of 2012 to 2016), oil prices were very high: West Texas Intermediate (WTI) oil prices between 2012 and mid 2014 averaged $97/barrel. More recently oil prices have been below $30/barrel briefly and mostly below $55/Barrel. The high oil prices resulted in over investment in gas production, over deployment of gas shale technology, and over production. Most gas production involves oil production and vice versa.[21] Lower prices in oil and gas have not been at sustainable levels in recent years, and resulted in numerous bankruptcies and a drilling collapse.

[21] Natural gas liquids are chemically intermediate between natural gas and oil, however, are often categorized as oil. In this context, natural gas liquids are considered oil.

Exhibit 8
Historical Henry Hub Gas Prices

Year	Henry Hub (Nom $/MMBtu)	Henry Hub (2016$/MMBtu)
2000	4.31	5.87
2001	3.96	5.27
2002	3.38	4.43
2003	5.47	7.03
2004	5.89	7.37
2005	8.69	10.53
2006	6.73	7.91
2007	6.96	7.97
2008	8.88	9.97
2009	3.95	4.40
2010	4.40	4.84
2011	4.00	4.32
2012	2.76	2.92
2013	3.73	3.89
2014	4.36	4.47
2015	2.64	2.67
2016	2.51	2.51
Average 2000-2016	**4.86**	**5.67**
Average 2009-2016	**3.54**	**3.75**
Average 2012-2016	**3.20**	**3.29**

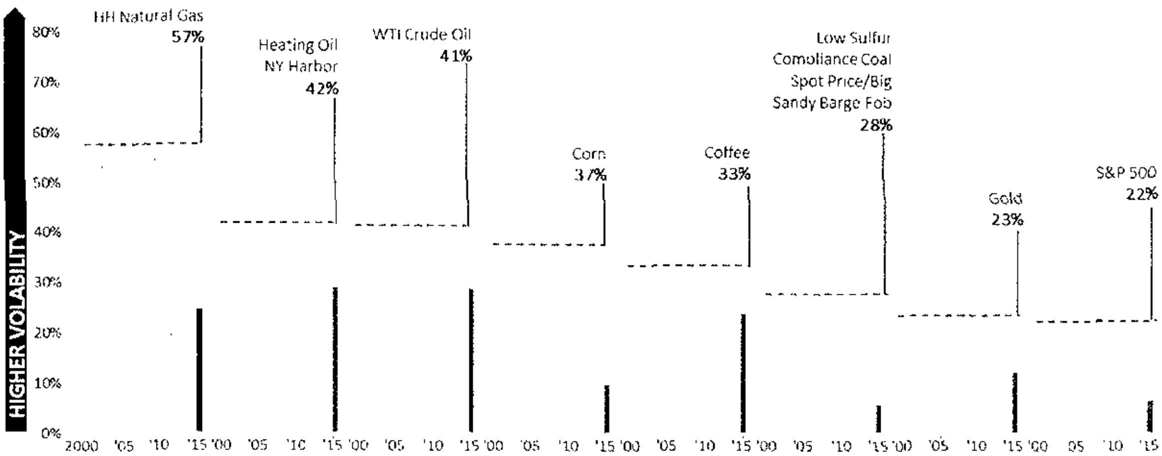
Source: SNL Financial

Q. ARE NATURAL GAS PRICES VOLATILE?

A. Yes. Natural gas is regularly the commodity with the most volatile prices and this volatility is amplified by short term contracting – e.g. spot or a month at a time (see Exhibit 9). In contrast, coal contracting is 1-5 years with 3 year very common.

Exhibit 9

Volatility of the Most Traded Commodities on the NYMEX



Source: S&P 500 prices were obtained from Google Finance. Other prices were obtained from Bloomberg. 2015 reflects the trades as of 5/22/2015.

Q. WHAT HAS BEEN THE LATEST TRENDS IN HENRY HUB SPOT PRICES?

A. Most recently, Henry Hub spot prices dramatically recovered in anticipation of normal (i.e. average) weather conditions. Between November 2015 and January 2016, Henry Hub spot prices averaged $2.10/MMBtu. In March 2016, Henry Hub spot prices averaged $1.72/MMBtu; this was the lowest monthly average since December 1998. Between November 2016 and January 2017, Henry Hub spot prices averaged $3.15/MMBtu which is 50% above prices in the same time period one year earlier and 83% above March 2016.

Q. WHAT HAS BEEN HAPPENING WITH NYMEX HENRY HUB GAS FUTURES PRICES?

A. The 2017 delivery gas futures price increased significantly over the last 12 months (see Exhibit 10). 2017 futures bottomed at $2.47/MMBtu on February 25, 2016, and peaked at $3.7/MMBtu on December 28, 2016 – that is in ten months the price increased 50%. Therefore, futures gas prices can also rise significantly quickly, and correlate with spot prices.

Exhibit 10
Monthly Average Henry Hub Futures of Year 2017

Year	Month	Nom$/MMBtu
2016	Jan	2.76
2016	Feb	2.61
2016	Mar	2.71
2016	Apr	2.86
2016	May	2.95
2016	Jun	3.08
2016	Jul	3.16
2016	Aug	3.09
2016	Sep	3.12
2016	Oct	3.27
2016	Nov	3.06
2016	Dec	3.47
2017	Jan	3.38

Source: SNL Financial.
Note: January 2017 futures of year 2017 includes the Futures for the month of January 2018 to provide a full 12-month period

Q. WHY ARE DOMINION SOUTH GAS PRICES IMPORTANT?

A. As noted, Dominion South is a gas marker for prices in the Marcellus and Utica shale plays.

Q. HOW DOES DOMINION SOUTH GAS PRICES AFFECT POWER PRICES?

A. Some powerplants purchase gas based on a Dominion South index price. However, all powerplants also pay other charges for gas delivery, and in some case these charges can be significant compared to Dominion South. In addition, one of the reasons Dominion South prices have been low is that only a limited amount of gas powerplants access gas from this area because of infrastructure constraints.

Q. WHAT HAVE DOMINION SOUTH GAS PRICES BEEN?

A. As shown in Exhibit 11, until 2012, Dominion South gas prices were at a premium to Henry Hub. In general, in the US, natural gas flowed from the Southwest to the Northeast. However, as Marcellus and Utica gas production expanded, prices switched to a large discount to Henry Hub. From 2014 to 2016, the discount averaged $1.07/MMBtu. This discount reflected a combination of lower costs, excess production, and lack of take away pipeline infrastructure.

Exhibit 11
Historical Dominion South Gas Prices

	Henry Hub		Dominion South		Basis WRT HH	
Year	(Nom$/ MMBtu)	(2016$/ MMBtu)	(Nom$/M MBtu)	(2016$/ MMBtu)	(Nom$/ MMBtu)	(2016$/ MMBtu)
2005	8.69	10.53	9.24	11.19	0.55	0.67
2006	6.73	7.91	7.08	8.33	0.35	0.42
2007	6.96	7.97	7.41	8.48	0.44	0.51
2008	8.88	9.97	9.33	10.48	0.45	0.50
2009	3.95	4.40	4.26	4.75	0.31	0.35
2010	4.40	4.84	4.60	5.07	0.21	0.23
2011	4.00	4.32	4.13	4.46	0.13	0.14
2012	2.76	2.92	2.78	2.95	0.02	0.03
2013	3.73	3.89	3.52	3.67	-0.20	-0.21
2014	4.36	4.47	3.30	3.38	-1.06	-1.09
2015	2.64	2.67	1.50	1.52	-1.14	-1.16
2016	2.51	2.51	1.50	1.50	-1.00	-1.00
Average 2005-2016	4.97	5.53	4.89	5.48	-0.08	-0.05
Average 2009-2016	3.54	3.75	3.20	3.41	-0.34	-0.34
Average 2012-2016	3.20	3.29	2.52	2.60	-0.68	-0.69

Source: SNL Financial
Note: Dominion South is reported without LDC charges.

Q. WHAT HAS BEEN THE LATEST TRENDS IN DOMINION SOUTH PRICES?

A. Most recently, Dominion South prices have dramatically recovered. In the first ten months of 2016, Dominion South prices averaged $1.31/MMBtu, which was a discount to Henry Hub of $1.09/MMBtu. Between November 2016 and January 2017, Dominion South prices averaged $2.65/MMBtu, an increase of 102% relative to the first ten months of 2016. During this recent period, the discount was $0.50/MMBtu with respect to Henry Hub, a decrease of 54% relative to the first ten months of 2016. This discount was smaller than any three month period since May 2014.

Q. WHAT IS CAUSING DOMINION SOUTH PRICES TO RISE AND APPROACH HENRY HUB PRICES?

A. We are continuing our review of this price recovery. We believe this is in part due to additional take away pipeline capacity, weather, and more importantly, decreasing supply of drilled but uncompleted wells. A decrease in drilled but uncompleted wells can indicate that the excess supply that accumulated in recent years (during the boom, excessive drilling took place during the period of very high oil prices, and some drilled wells were not completed – i.e. not fracked) is decreasing.

Q. DID THIS REFLECT AN EXTREMELY COLD WEATHER?

A. No, the increase in price occurred in spite of a mild early winter – i.e. a mild January. Since 2010, only one January was warmer than January 2016 in the East

North Central region that includes Ohio: January 2012, which was the warmest January on record. All else equal, a normal winter or a colder than normal winter would have resulted in even higher prices.

Q. WHAT ARE THE REASONS WHY HENRY HUB GAS PRICES ARE RECOVERING FROM 2016 LEVELS?

A. The recovery is a result in part due to winter 2015/2016 which was the warmest ever. In addition, there has been a massive decrease in drilling, and a long term trend of rising gas demand. Oil/gas drilling has decreased over the last few years, bottoming out in May 2016 at 80% below peak levels in November 2011. Producers are responding to lower natural gas/oil/Natural Gas Liquids (NGLs which include propane) prices by reducing exploration and production activity, which will in turn reduce production growth. On the demand side, I highlight:

- US pipeline exports of natural gas to Mexico have increased from 0.62 TCF in 2012 to 1.25 TCF through November 2016, an increase of 101%.
- US consumption of natural gas has increased between 2012 and 2016 by 1.7 TCF an increase of 7%. I highlight 2012, which was, like 2016, very warm.
- The US has started exporting LNG from the lower 48 states starting in February 2016. Currently 10.4 BCFd of LNG export capacity is

contracted and under construction. In contrast, the average US demand is approximately 75 BCFd.

Q. PLEASE ELABORATE ON THE DRILLING SITUATION AND ITS IMPLICATIONS FOR GAS PRICES.

A. Total well drilling is divided into gas directed and oil directed. Between late 2011 and February 2016, the sum of gas and oil directed drilling decreased 75%, and the sum of the two measures is the best assessment of how much drilling has decreased. This is because wells often produce a diversity of hydrocarbons and wells self-identify as oil or gas using varying criteria.

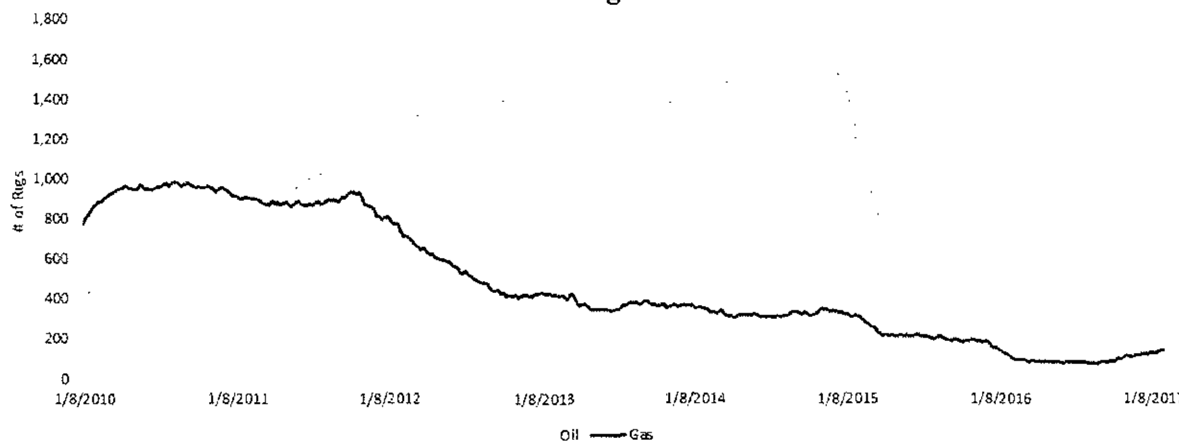
In addition, U.S. natural gas directed drilling was close to a rig count of 81 as of August 26, 2016, its lowest level since 1985. The decrease in gas-directed well drilling was 90% since December 2011, and the decrease continued until very recently. Over the last two years, well drilling was approximately 100-200 wells versus 800 to 1000 wells in the 2010 to 2011 period. In spite of growing well productivity over time, this is consistent with 2016 natural gas prices being too low to meet future gas demand. A shale well is not like a typical factory with a relatively fixed maximum annual output level. Rather output depletes over time. Within 5 years, a shale gas well's maximum output decreases 60% to 70%. Thus, in order to maintain a constant level of production, drilling must stay high enough to offset the large declines in production rates of existing wells. To illustrate, by 2022, in the absence of any drilling, ICF estimates that the U.S. would lose approximately two-thirds of its gas or shale gas output. Thus, current low prices cannot be sustained even if gas demand does not grow, because current low drilling levels mean that production will decline and exert upward pressure on prices.

In addition, as shown in Exhibit 12 below, oil well drilling has similarly significantly declined. Over nine months (from 12/4/2015 to 8/26/2016), oil drilling has decreased by nearly 26%. Drilling that is primarily oil based also produces significant amounts of natural gas, and is therefore also an important indicator of future gas production. Further, the natural gas produced from oil wells is usually low cost natural gas since the gas is often a co-product of producing oil. Hence, the decrease in oil drilling is removing a low cost natural gas supply resource.

Q. **WHAT IS THE RELATIONSHIP BETWEEN GAS DRILLING AND GAS PRICES?**

A. The decrease in drilling will result in decreased supply available to meet demand, because in the absence of new production, existing production levels fall. Lower supply will raise prices. As noted, in the absence of drilling, ICF estimates that gas production from all existing wells (every U.S. well drilled and completed through the end of 2016) [redacted]. Hence, gas prices will increase.

Exhibit 12
US Oil and Gas Rig Count



Source: Baker Hughes, from January 8, 2010 to Feb 3, 2017

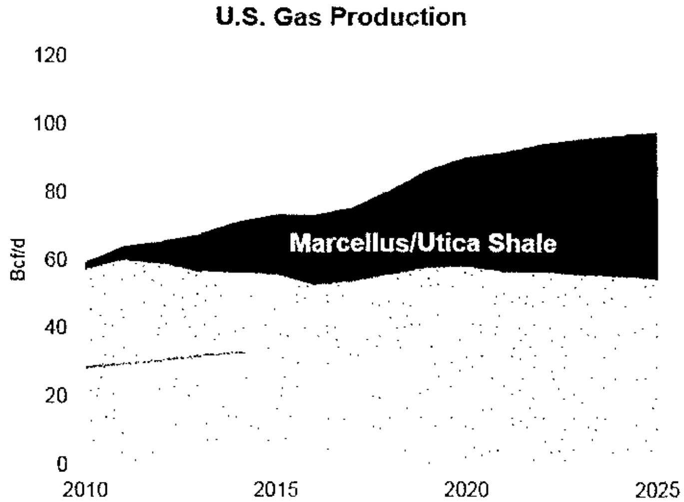
Q. WHAT IS THE RELATIONSHIP BETWEEN FUTURE MARCELLUS PRODUCTION AND NATURAL GAS PRICES?

A. Marcellus and Utica[22] is the largest growing gas producing area in the U.S., and even though ICF projects a doubling of Marcellus output between 2015 and 2022, gas prices still increase (see Exhibit 13). This projection cannot be achieved without growth in drilling, and the prices to achieve and sustain required levels of drilling. Also, in the Marcellus, like wells in other so called unconventional areas, wells exhibit higher depletion rates than so called conventional well. As shown in Exhibit 14, each colored section of the figure is the output of wells in their first year, and the narrowing over time for each colored section captures the decline of the well output. As Marcellus grows, the amount of drilling grows faster than if there were not this phenomenon of output decline. Thus, in the long run, even though Marcellus growth is projected to be large, 45% of the drilling is just to maintain output at 2014 levels. Exhibit 16 shows the relationship of the

[22] Whenever referring to Marcellus we are also including Utica.

decline in production for wells drilled before 2015 with production of wells drilled after 2015.

Exhibit 13
Marcellus & Utica Gas Production

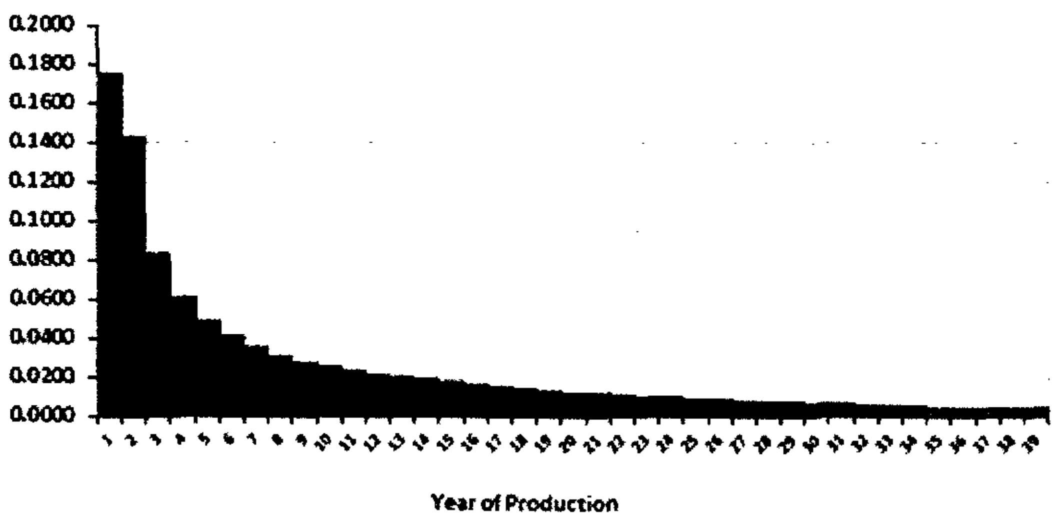


Marcellus & Utica Shales

Year	Well Completions	Production (Bcf/d)
2010	956	2
2011	1,565	4
2012	1,797	7
2013	2,131	11
2014	2,572	15
2015	2,243	18
2016	1,450	21
2017	1,461	22
2018	2,447	25
2019	2,617	29
2020	3,084	32
2021	3,126	35
2022	3,287	38
2023	3,195	40
2024	3,199	42
2025	3,068	43

Source: ICF

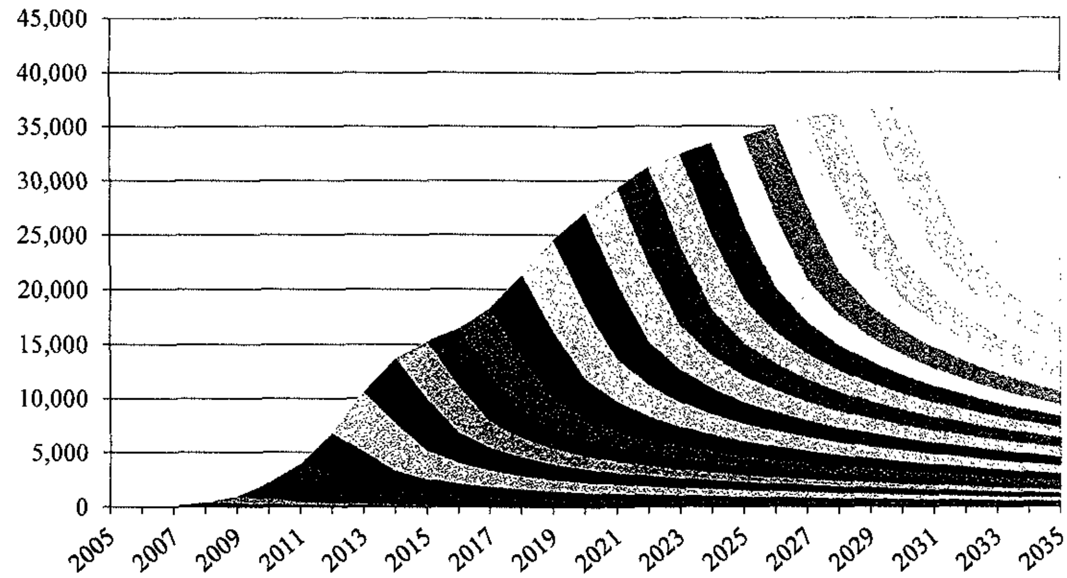
Exhibit 14
Gas Well Decline Curve
Fraction of Reserves Produced In Each Year



Source: ICF

Exhibit 15

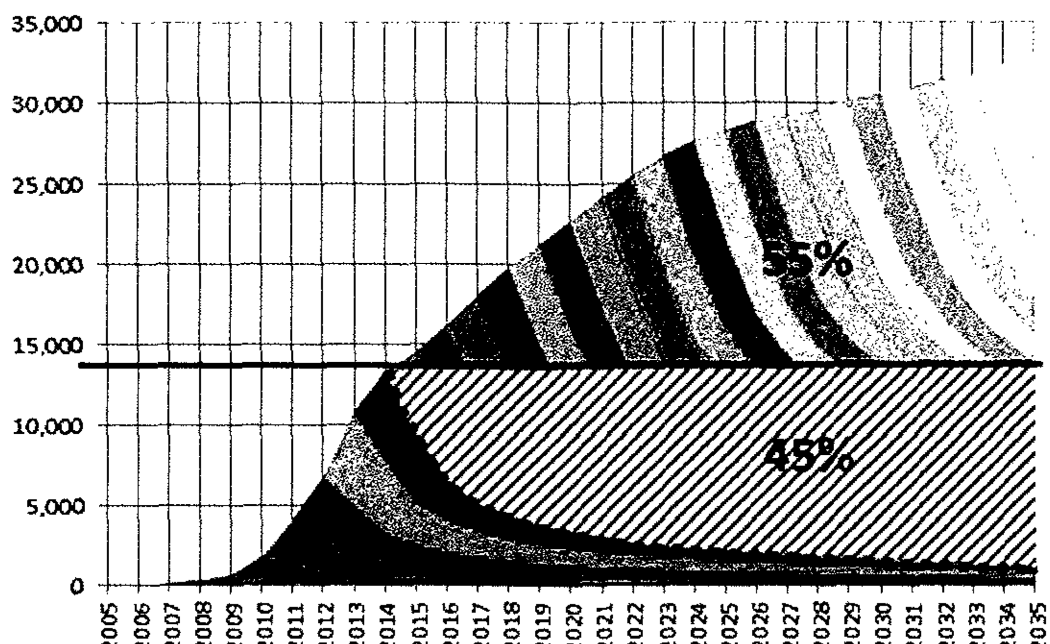
Vintaged Production of Natural Gas (MMcfd)



Source: ICF, see the text above for description of graphic

Exhibit 16

Vintaged Production of Natural Gas (MMcfd)



Source: ICF, see the text above for description of graphic

Note: The diagonal area shows the amount of cumulative production that must be replaced over time.

Q. HOW DO YOU DEVELOP YOUR GAS PRICE FORECASTS?

A. Our approach to natural gas pricing is to use futures in the near term and transition to ICF's fundamentals-based view in 2020. Specifically, we use futures for 2017 and 2018 and, in 2020, the model reflects ICF's view of the fundamentals of the energy market – 2019 is an interpolation. Beginning in 2020, natural gas prices are projected using ICF's Gas Market Model ("GMM"). GMM is a full supply/demand equilibrium model of the North American natural gas market. Our forecast is that the recent multi-year trend (e.g., post 2008) of low supply area natural gas prices will continue in the near-term, but over time, natural gas prices increase in real terms and even more in nominal terms relative to 2016. As noted, this reflects the impacts of large increases in demand as investments in equipment using natural gas come on-line (e.g., LNG exports, new petro-chemical facilities) and natural gas use in the power sector grows.

Q. WHY DO YOU NOT USE GAS FUTURES AFTER 2018?

A. The liquidity of gas futures is very low – i.e. there are very few transactions as most contracting for gas is very short term. Over time, the reported prices may not even reflect transactions, but rather bids and asks, and even small transactions can move the price a lot. Note, that for the year 2019, we use the average of the 2018 futures and ICF's forecast for 2020.

Q. WHAT IS YOUR HENRY HUB GAS MARKET PRICE FORECAST?

A. Exhibit 17 presents ICF's natural gas price forecast in real and nominal dollar terms. [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL] In the mid-2020s, natural gas prices would be higher except that we forecast that recent developments decreases greatly the prospects for significant national CO_2 emission regulations. CO_2 emission regulations support more replacement of coal by gas, higher demand for gas, and hence, higher gas prices, all else equal.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Exhibit 17

[BEGIN CONFIDENTIAL] [redacted]
[END CONFIDENTIAL]

Over the longer term, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Our view is that abundant natural gas supplies, particularly from the development of shale gas, will continue to depress natural gas prices in the long-term relative to average prices over the 2000 to 2008 period, but natural gas prices [redacted] (see Exhibit 18 and 19). Further, there will be very large year-by-year volatility due to weather and economic and industry cycles. Volatility will be especially pronounced in demand areas, also referred to as market areas, where there is an imbalance between natural gas demand and natural gas delivery infrastructure.

[BEGIN CONFIDENTIAL] [redacted]

[END CONFIDENTIAL]

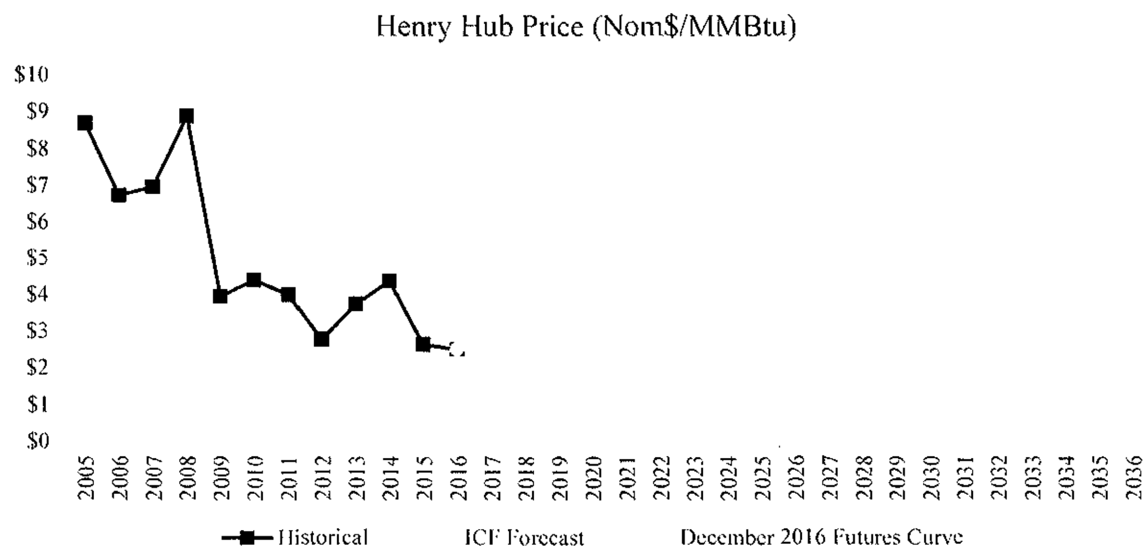
[BEGIN CONFIDENTIAL] [redacted]

[END CONFIDENTIAL]

Lastly, in the long-term, ICF forecasts of natural gas prices are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] As noted, while NYMEX futures volumes are extremely low past the prompt year (i.e., the next 12 months), and the following 1 to 2 years, ICF does not rely upon them in the mid to long-term. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The forecasts reflect ICF modeling including assumptions, model methodology, and other input data. The

NYMEX futures price is very illiquid in later years and does not reflect specific supply and demand assumptions, but rather transactions. We show the NYMEX futures as a point of reference for those familiar with the NYMEX futures (see Exhibit 20).

[BEGIN CONFIDENTIAL] [redacted]



[redacted]

[END CONFIDENTIAL]

Q. HOW DOES YOUR NATURAL GAS PRICE FORECAST COMPARE TO THAT OF THE US EIA FORECAST?

A. The only public forecast using generally accepted methodology for the entire period the US EIA *Annual Energy Outlook (AEO)* forecast. ICF's forecast of Henry Hub nominal gas prices is [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

BEGIN CONFIDENTIAL] [redacted]

[redacted]	AEO 2017 Henry Hub (Nom $/MMBtu)	AEO 2017 Henry Hub (2016$/MMBtu)
	3.06	3.00
	3.55	3.40
	4.22	3.96
	4.90	4.51
	4.88	4.39
	4.83	4.26
	4.97	4.28
	5.23	4.41
	5.45	4.51
	5.74	4.64
	6.01	4.75
	6.29	4.86
	6.56	4.96
	6.76	5.00
	7.05	5.11
	7.20	5.11
	7.23	5.03
	7.33	5.00
	7.60	5.09
	7.71	5.07
	7.86	5.07
	7.98	5.05
	8.17	5.08
	8.31	5.07
	4.68	**4.14**
	7.29	**5.02**
	6.20	**4.65**

[redacted]

[END CONFIDENTIAL]

Q. WHAT IS YOUR DOMINION SOUTH GAS MARKET PRICE FORECAST?

A. Exhibit 22 presents ICF's Dominion South gas price forecast in real and nominal dollar terms. In 2017, futures for Dominion South gas prices are $2.13/MMBtu in nominal dollars and $2.09/MMBtu in 2016 dollars. By 2026, natural gas prices will [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Exhibit 22

[BEGIN CONFIDENTIAL] [redacted]

Year	Source	Henry Hub (2016$)	Henry Hub (Nom$)	Dominion South (2016$)	Dominion South (Nom $)	Basis WRT HH (2016$)	Basis WRT HH (Nom$)
2012	Historical	2.92	2.76	2.95	2.78	0.03	0.02
2013	Historical	3.89	3.73	3.67	3.52	-0.21	-0.20
2014	Historical	4.47	4.36	3.38	3.30	-1.09	-1.06
2015	Historical	2.67	2.64	1.52	1.50	-1.16	-1.14
2016	Historical	2.51	2.51	1.50	1.50	-1.00	-1.00
2017[1,3]	NYMEX Futures[1]	3.37	3.44	2.09	2.13	-1.28	-1.31
2018	NYMEX Futures[1]	2.95	3.08	2.10	2.19	-0.85	-0.89
2019	Average of Futures[1] and ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average (2012-2016)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2017 – 2026		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2027 – 2040		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2017 – 2040		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

VI. MODELING ASSUMPTIONS – COAL

Q. WHAT TYPE OF COAL IS USED AT CLIFTY CREEK AND KYGER CREEK?

A. Both plants use high sulfur eastern US bituminous coal delivered by barge. Clifty Creek typically uses Illinois Basin coal and Kyger Creek typically uses Northern Appalachia coal. The plants have attractive locations for coal delivery. The plants have barge access to the Ohio River which is typically the lowest cost transportation mode per mile. Barge access creates the ability to procure from the following production areas: Northern Appalachia (which includes Ohio, Pennsylvania, and northern West Virginia), Central Appalachia (which includes southern West Virginia and Eastern Kentucky), and Illinois Basin (which includes Western Kentucky, Indiana, and Ohio). OVEC can also deliver western Powder River Basin coal via rail and barge. Access to so many coal sources creates greater procurement flexibility as does on site coal inventory.

Q. WHAT WERE DELIVERED COAL PRICES AT CLIFTY AND KYGER CREEK OVER THE LAST FIVE YEARS?

A. As shown in Exhibit 23, delivered coal costs at Clifty and Kyger Creek were \$2.23/MMBtu and \$1.91/MMBtu respectively in 2016. The 2012 to 2016 averages were \$2.60/MMBtu and \$2.04/MMBtu respectively.

Exhibit 23
Historical Delivered Coal Costs for the OVEC Plants

	Kyger Creek		Clifty Creek	
Year	**2016$**	**Nom$**	**2016$**	**Nom$**
2012	2.28	2.15	2.90	2.73
2013	2.20	2.11	2.75	2.63
2014	2.15	2.09	2.99	2.92
2015	1.94	1.92	2.53	2.49
2016	1.91	1.91	2.23	2.23
Average (2012-2016)	**2.10**	**2.04**	**2.68**	**2.60**

Source: SNL Financial

Q. WHAT HAS BEEN HAPPENING TO SPOT COAL PRICES?

A. Spot coal prices have been decreasing. In 2016, spot prices for high sulfur coal from both Northern Appalachia and in the Illinois Basin for barge averaged $1.62/MMBtu, 19% below 2012 levels. $1.62/MMBtu is 38% below average Clifty Creek delivered 2012 to 2016 prices and 21% below average Kyger Creek delivered 2012 to 2016 prices. Thus, even when accounting for barge costs (typically $0.1/MMBtu to $0.25/MMBtu), delivered spot prices are below historical delivered coal prices by a significant amount – approximately 30% lower for Clifty Creek.

Exhibit 24
Historical NAPP and Illinois Basin Coal Spot Prices

	NAPP, Upper Ohio River Barge, 12500 btu/lb, > 6 lb/mmBtu Sulfur				Illinois Basin Barge, 11000 btu/lb, 5 lb/mmBtu Sulfur			
	Nom$		2016$		Nom$		2016$	
Year	**$/ton**	**$/MMBtu**	**$/ton**	**$/MMBtu**	**$/ton**	**$/MMBtu**	**$/ton**	**$/MMBtu**
2012	49.1	1.96	52.0	2.08	44.5	2.02	47.1	2.14
2013	55.0	2.20	57.3	2.29	42.4	1.93	44.2	2.01
2014	57.5	2.30	58.9	2.36	45.2	2.05	46.3	2.10
2015	50.6	2.02	51.3	2.05	40.0	1.82	40.5	1.84
2016	40.5	1.62	40.5	1.62	35.8	1.63	35.8	1.63
Avg (2012-2016)	**50.5**	**2.02**	**52.0**	**2.08**	**41.6**	**1.89**	**42.8**	**1.94**

Source: SNL Financial

Q. PLEASE DISCUSS COAL PROCUREMENT.

A. Reasonable coal purchasing can have a range contractual arrangements. For example, most coal is purchased on a spot basis, the exact spot share can vary. Similarly, contracted coal can have a range of tenure and the shares open to market reopeners. Regardless, coal purchasing is much less volatile than gas purchasing. For example, spot coal purchasing is not as volatile a strategy as spot gas purchasing. Over the 2012 to 2016 period, the spot annual price range for coal was $0.42/MMBtu versus $1.85/MMBtu for Henry Hub gas; the gas range was 4.4 times higher. Also, over the 2012 to 2016 period, spot coal prices were lower on average than average delivered coal costs by $0.30/MMBtu in nominal terms.

Q. HOW DO YOU FORECAST COAL PRICES?

A. I use ICF's IPM model to forecast coal production, price and transportation simultaneously with other parameters such as power prices, plant operation, capacity expansion, etc. In IPM®, coal pricing is endogenously solved for in the model. Coal reserves and production are tracked and classified as coming from one of 40 U.S. coal supply regions or 24 international coal supply regions. Coal supply curves for each of the 40 domestic supply regions are created in CoalDOM®, an ICF modeling tool, by assigning every existing coal mine to one of 16 prototypical coal costing models. A coal supply curve is generated for each coal type produced from each coal supply region for each year. The coal types are differentiated by rank, heat content, and sulfur content. The coal types also differ in mercury, chlorine, and carbon content depending on the source region.

The coal supply curves are then used as inputs to IPM®. Coal plants in IPM® are assigned to one of 300 different coal demand regions that are defined by location and mode of delivery. A coal transportation matrix links supply and demand regions in IPM®, which determines the least cost means to meet electric power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.

Q. WHAT IS YOUR FORECAST OF COMMODITY COAL PRICES?

A. Coal prices are forecast to be [redacted] for Kyger Creek and especially Clifty Creek over the 2012 to 2016 period. Actual average Kyger Creek and Clifty Creek prices are [redacted] due to legacy contracts. Over time, we forecast coal prices [redacted] on average over time. For example, Northern Appalachia high sulfur 6 lb. SO_2/MMBtu coal prices are projected [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] [redacted]

	[redacted]				[redacted]			
	[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

Q. WHAT IS YOUR FORECAST OF DELIVERED COAL PRICES TO THE OVEC PLANTS?

A. As shown in Exhibit 26, delivered coal costs at Clifty and Kyger Creek are forecast to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] These projections includes estimates of the cost impacts from existing OVEC coal contracts.

[BEGIN CONFIDENTIAL] [redacted]

	[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]	
	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

VII. MODELING ASSUMPTIONS – OTHER

Q. WHAT IS YOUR FORECAST OF DEMAND FOR ELECTRICTY?

A. Projected peak and energy demand for PJM for the 2017 - 2040 time period are based on PJM's 2017 forecast; we extrapolate beyond the ten year PJM forecast. Regional forecasts for AEP Dayton demand are also from PJM's 2017 forecast. Exhibit 27 below provides an overview of the PJM RTO demand assumptions. PJM peak and energy demand are forecasted to grow at approximately 0.16 percent and 0.23 percent per year respectively in the near-term from 2017-2026. Electricity demand at peak will grow at 0.23 percent per year from 2016 levels on a weather normalized basis over the 2017 to 2040 time period. Over this same time period, AEP Dayton's growth is slightly higher at 0.5 percent. Growth rates are calculated before accounting for DSM levels.

Exhibit 27
PJM RTO Zone Demand Forecast

Year	Energy Demand (GWh)		Peak Demand (MW)	
	Energy	Growth	Peak	Growth
2017	814,838		153,001	
2018	821,638	0.83%	153,950	0.62%
2019	823,890	0.27%	154,279	0.21%
2020	822,831	-0.13%	153,684	-0.39%
2021	820,415	-0.29%	153,383	-0.20%
2022	821,341	0.11%	153,423	0.03%
2023	822,626	0.16%	153,723	0.20%
2024	827,522	0.60%	154,143	0.27%
2025	827,944	0.05%	154,574	0.28%
2026	831,502	0.43%	155,147	0.37%
2027	835,137	0.44%	155,772	0.40%
2028	841,099	0.71%	156,421	0.42%
2029	842,931	0.22%	157,013	0.38%
2030	843,429	0.06%	157,230	0.14%
2031	845,602	0.26%	157,511	0.18%
2032	851,227	0.67%	157,992	0.31%
2033	855,171	0.46%	158,379	0.24%
2034	859,145	0.46%	158,769	0.25%
2035	863,150	0.47%	159,163	0.25%
2036	867,185	0.47%	159,561	0.25%
2037	871,251	0.47%	159,962	0.25%
2038	875,348	0.47%	160,368	0.25%
2039	879,476	0.47%	160,777	0.26%
2040	883,636	0.47%	161,189	0.26%
Average 2017-2026	**823,455**	**0.23%**	**153,931**	**0.16%**
Average 2027-2040	**858,128**	**0.44%**	**158,579**	**0.27%**
Average 2017-2040	**843,681**	**0.35%**	**156,642**	**0.23%**

Source: PJM-ISO, "PJM 2017 Load Forecast", January 2017

Q. WHAT ARE YOUR FORECASTS FOR DEMAND RESOURCES (DR)?

A. In PJM's most recent capacity auction for the capability period 2019/2020, DR was 46 percent of the planning reserves. The PJM planning reserve margin is assumed to be 15.8 percent, the average of last five capacity auctions. This level of DR is assumed to decrease to levels forecast by PJM in response to the implementation of 100% capacity performance procurement for the first time. This decrease is large at 54% between the 2019/2020 auction and the 2020/2021 BRA auction.

Thereafter we conservatively assume it will be maintained throughout the forecast as the same proportion of demand, and therefore, will not depress capacity prices in the future to the same extent as it has in the recent past.

Exhibit 28
PJM Demand Resource Participation in Base Residual Auctions

DR Type	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
ILR	2,107	2,110	2,108	2,110	1,594	NA	NA	NA	NA	NA	NA	NA	NA
DR Cleared	128	536	893	939	1,365	7,047	9,282	14,118	14,833	12,408	10,975	11,084	10,348
EE Cleared	NA	NA	NA	NA	NA	569	679	822	923	1,117	1,339	1,247	1,515
Total DSM	**2,235**	**2,646**	**3,001**	**3,049**	**2,959**	**7,616**	**9,961**	**14,941**	**15,755**	**13,525**	**12,314**	**12,331**	**11,863**
Demand Requirements													
Peak Demand	137,421	139,806	142,177	144,592	142,390	144,857	160,634	164,758	163,168	165,412	164,479	161,418	157,188
DR as% of Demand Requirements													
% of Peak	1.6%	1.9%	2.1%	2.1%	2.1%	5.3%	6.2%	9.1%	9.7%	8.2%	7.5%	7.6%	7.5%
% of Target Reserves	11%	13%	14%	14%	13%	34%	39%	59%	63%	52%	48%	49%	46%
Target Reserve Margin %	15.0%	15.0%	15.0%	15.5%	15.5%	16.2%	15.3%	15.3%	15.4%	15.6%	15.7%	15.7%	16.5%

Source: PJM-ISO

The last auctions have seen a decrease in DR by roughly 4%; with total DR clearing at 7.5% of peak in the 2019/20 auction (see Exhibit 28). This supports the conclusion that the depression of PJM capacity prices by DR is unlikely to be the same extent.

[BEGIN CONFIDENTIAL] [redacted]

[END CONFIDENTIAL]

Q. WHAT ARE YOUR ASSUMPTIONS ABOUT FIRM PJM BUILDS AND RETIREMENTS?

A. Firm builds and retirements are set exogenously for near term announced and highly likely capacity additions and withdrawals – i.e. they are "hard wired". We assume firm new combined cycle builds will total approximately 4,200 MW by 2017, and 16,000 MW by 2019. Over the 2010 to 2019 time period, firm retirements cumulatively are 29,000 MW (see Exhibit 30). In addition, ICF's IPM model can decide to retire or add plants on a non-firm basis based on economics. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Exhibit 30
PJM - Firm Builds and Retirements (GW)

	Year	Retirements (MW)	Firm Builds - Combined Cycle (MW)
PJM	2010	786	0
	2011	1,325	1,215
	2012	7,027	1,418
	2013	2,859	0
	2014	2,967	2,246
	2015	10,061	1,724
	2016	407	3,710
	Total (2010-2016)	**25,431**	**10,313**
	2017	1,918	4,199
	2018	1,013	6,293
	2019	710	5,422
	Total (2017-2019)	**3,641**	**15,914**
	Total (2010-2019)	**29,071**	**26,227**

Source: PJM-ISO; SNL Financial

Q. WHAT ARE YOUR ASSUMPTIONS ABOUT NATIONAL ENVIRONMENTAL REGULATIONS TO LIMIT CO_2?

A. In August 2015, the US EPA finalized the Clean Power Plan (CPP) which regulates CO_2 emissions of powerplants. In February 2016, the US Supreme Court issued a stay of the CPP. Recent developments significantly decrease the likelihood of a near term national CO_2 control program. ICF forecasts that there will be a federal CO_2 program starting on January 1, 2027. The assumed program is in the form of a cap and trade program, and therefore, there is a \$/ton CO_2 emission allowance price. The price is equal to the marginal cost of CO_2 control, and reflects a probability weighted expected value (see Exhibit 31). Specifically, ICF assessed several proposed utility sector CO_2 control programs using ICF's IPM model. ICF gave probabilities to two of these cases based on its judgment on likelihood and also gave probabilistic weight to a scenario in which there is no national CO_2 price (\$/ton). Note, the price does not reach [redacted] Therefore, the programs is not a significant factor until the 2030s. Notwithstanding, the modeling anticipates the CO_2 program by minimizing discounted present value of costs.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[END CONFIDENTIAL]

ICF's preliminary assessment of implementation by Ohio and other states of the CPP resulted in a value similar to the expected national program in the pre-2030 period.

Q. WHAT ARE YOU ASSUMING ABOUT NON-CO_2 ENVIRONMENTAL REGULATIONS?

A. My forecast tracks a number of non-CO_2 environmental regulations including CSAPR for SO_x and NO_x control, the Mercury and Air Toxic Standards Rule for mercury control, Section 316(b) for control of cooling water withdrawals, ash handling is controlled through coal combustion residual regulations, and the impacts of EPA's Effluent Limitations Guidelines are also included. In general, the current administration is likely to significantly change environmental regulations in favor of coal generation. Coal generation will benefit from the greatly decreased near-term likelihood of national CO_2 emission regulations and other regulatory initiatives that increase the cost of operating coal plants. ICF has updated its forecasts to account for this development.

Q. WHAT ARE YOU ASSUMING REGARDING CAPITAL AND FINANCING COSTS FOR NEW BUILDS?

A. New combined cycle plants are assumed to be available in 2020, approximately at \$931/kW (2016\$) in the AEP-Dayton region.[23] In equilibrium in the long-term, an important driver of scarcity or capacity prices is the annual costs of new entry (i.e., entry by a new natural gas-fired combined cycle). New simple-cycle units are assumed to have capital investment costs that are approximately 35 percent[24] lower relative to combined cycles, depending upon the region and year of build.

---

[23] This reflects the underlying assumption of a generic GE HA.01 class combined cycle with a 6,500 Btu/kWh heat rate. The price is expressed in \$/summer kW.

[24] The 35% is the outcome of ICF studies of new natural gas-fired unit capital costs.

New power plant costs vary by region as a function of variation in underlying labor and material costs, ambient conditions, local environmental regulations (to the extent applicable), etc.

Financing assumptions are also important because the annual costs of capital investment are a function of both financing costs and capital costs.

ICF has assessed the required rate of return for new entrants using the Capital Asset Pricing Model ("CAPM"). We have calculated the merchant cost of equity requirement ("ROE") to be approximately 12.5 percent. Ultimately, this leads to a nominal after-tax weighted average cost of capital ("WACC") of approximately 8.7 percent.

ICF assumes that new units will have lower returns and/or costs thereby decreasing capacity prices compared to a cost of capital that fully reflects the higher risks of merchant power plants. This is consistent with our historical observation of market conditions that result in lower capacity prices relative to true merchant CONE. This reflects several factors, including temporary discounts of equipment costs, temporary periods of low financing costs, use of brownfield sites, select locations of temporary natural gas basis advantages, greater economies of scale, imperfections in the power markets (e.g., price caps and market intervention) and the availability, in some cases, of traditional utility financing and long-term power purchase agreements (e.g., industrial hosts contracting for power).

Q. WHAT DO YOU ASSUME ABOUT RENEWABLES?

A. ICF models the Renewable Portfolio Standards ("RPS") in place in each state. The model also has the option to add additional renewables in response to economic conditions. ICF forecasts the elimination of the Production Tax Credit in accordance with the current schedule which decreases the attractiveness of renewables, but RPS targets are not affected by the PTC. Thus, price forecasts reflect the impacts of renewables.

VIII. ELECTRICITY PRICE PROJECTIONS – ALL-HOUR ELECTRICAL ENERGY

Q. WHY ARE YOU FORECASTING ELECTRICITY PRICES?

A. My goal is to compare the costs of power from Clifty Creek and Kyger Creek with the costs of purchasing power from the market. Therefore, I need to forecast electricity market prices. I also address the issue of market price volatility.

Q. HAVE YOU CREATED A MARKET PRICE PROJECTION FOR ELECTRICAL ENERGY?

A. Yes. My forecast of wholesale power prices is based on computer modeling of the North American power grid's supply and demand fundamentals with a focus on PJM and the Ohio sub-zones. My forecasts cover April 1, 2017 through June 30, 2040.

Q. HOW WERE ELECTRICAL ENERGY PRICES FORECASTED?

A. I forecasted electrical energy prices by assuming prices equal the short run marginal costs of producing electrical energy – which is mostly fuel, and to a lesser degree, variable non-fuel O&M and emission allowance prices. As discussed, there is substantial variation in marginal generation equipment and demand which creates price variation over time – i.e. variation diurnally, across day types, seasonally and annually. These prices also reflect the impacts of transmission limitations, congestion and losses – i.e. there are also locational differences. We used computer models to project all electrical energy prices on an hourly basis. I have previously described the computer models used to make these projections.

Q. WHAT ELECTRICAL ENERGY PRICES DID YOU FORECAST?

A. We forecasts prices by hour by node by year and hence we forecast an extremely large number of prices. We focus on:

- AEP Dayton hub All-hour, real and nominal dollars
- Clifty Creek and Kyger Creek All-hour nodal, real and nominal dollars
- Realized Clifty Creek and Kyger Creek nodal prices, real and nominal dollars where realized refers to the prices in the hours in which the powerplants dispatch

Q. WHAT IS YOUR FORECAST OF AEP DAYTON ALL-HOUR ELECTRICAL ENERGY PRICES?

A. I forecast that the 2017 to 2040 AEP Dayton all-hour price will average approximately [BEGIN CONFIDENTIAL] [redacted] which fully incorporates the effects of general economy-wide inflation (see Exhibit 32). [redacted] the AEP Dayton all-hours electrical energy price will average approximately [redacted] in 2016$ (see Exhibit 33). [END CONFIDENTIAL]

The 2018 forecast is approximately [BEGIN CONFIDENTIAL] [redacted] (see Exhibit 33). The 2018 nominal forecast price is approximately [redacted] and the 2026 price is approximately [redacted] in nominal dollars. [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 32

[redacted]

Delivery Period	AEP-Dayton	Kyger Creek	Clifty Creek
	Hub Price	Nodal Price	Nodal Price
2017[1]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]
2040[2]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

1) 2017 is a partial year starting from April 1, 2017 to December 31, 2017.
2) 2040 is a partial year starting from January 1, 2040 to June 30, 2040.
Source: ICF

Exhibit 33

[redacted]
and [redacted]

Delivery Period	AEP-Dayton Hub Price	Kyger Creek Nodal Price	Clifty Creek Nodal Price
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]
2040[2]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

Q. HOW DO CLIFTY CREEK AND KYGER CREEK NODAL ALL-HOUR PRICES COMPARE TO THE AEP DAYTON HUB?

A. Nodal prices for the two powerplants are modestly [BEGIN CONFIDENTIAL] [redacted] the AEP Dayton hub prices. Between 2017 and 2025, I forecast that Clifty Creek and Kyger Creek all-hour nodal prices will be [redacted] the AEP Dayton all-hour price, respectively. [END CONFIDENTIAL] In comparison, over the 2012 to 2016 period, the all-hour nodal discount to the AEP Dayton hub price was 6% for Clifty Creek and 6% for Kyger Creek respectively.

Q. HOW DOES YOUR 2018 ELECTRICAL ENERGY PRICE FORECAST OF AEP DAYTON COMPARE TO 2016 PRICES?

A. In all future years in the forecast, electrical energy prices are [BEGIN CONFIDENTIAL] [redacted] 2016 on a nominal dollar basis. Specifically, in 2016, the average all-hour electrical energy price was $27.8/MWh. Thus, the 2018 forecast price of [redacted] than the 2016 price. Over the first ten years of the forecast, the 2017 to 2026 nominal average of [redacted] than the 2016 price. [END CONFIDENTIAL]

Q. [BEGIN CONFIDENTIAL] WHY IS YOUR FORECAST PRICE OF AEP DAYTON [redacted] FOR 2018 THAN 2016?

A. First, it is not surprising that prices are [redacted]. 2016 prices were lower than in any year since 2005[25] and 2016 prices were 20% lower than the 2009 to 2016 average price of $34.9/MWh. 2016 included the warmest US winter on

[25] SNL Financial's recording of AEP Dayton Hub price stops at 2005.

record, and 2016 annual Henry Hub gas prices were lower than any year since 1999.[26] Second, and more specifically, my forecast energy price for 2018 is [redacted] than the 2016 price because: (1) the Henry Hub gas price is [redacted] (2) the Dominion South gas prices is [redacted] and (3) energy demand is assumed to reflect normal weather, [redacted] [END CONFIDENTIAL]

Q. HOW DOES YOUR 2018 FORECAST OF AEP DAYTON COMPARE TO THE HISTORICAL 2012 TO 2016 AVERAGE?

A. My 2018 forecast price is [BEGIN CONFIDENTIAL] [redacted] than the 2012 to 2016 average. The average price for AEP Dayton between 2012 and 2016 was $34.9/MWh in 2016 real dollars compared to the 2018 forecast price of [redacted] - i.e. the 2018 forecast is [redacted]. [redacted] The 2012 to 2016 average Henry Hub and Dominion South gas prices were $3.29/MMBtu, and $2.60/MMBtu, respectively, both in 2016 dollars. In comparison, in the 2018 forecast, Henry Hub and Dominion South prices are forecast to be [redacted] END CONFIDENTIAL] A significant part of the difference is explained by the addition of new approximately 8,000

---

[26] The 2016 Henry Hub prices $2.51/MMBtu and the first lowest year before 2016 was 1999 at $2.27/MMBtu.

MW of new advanced combined cycles in PJM in 2016 and 2017 that lower the power price for a given gas price (see Exhibit 34).

Exhibit 34
Historical Electrical Energy Prices – All-Hours ($/MWh)

Source	Year	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]
		(2016$/MWh)	(2016$/MWh)	(Nom$/MWh)	(Nom$/MWh)
Historical	2009	36.8	34.9	33.0	31.3
	2010	41.4	39.4	37.6	35.8
	2011	41.8	39.2	38.7	36.4
	2012	33.1	32.0	31.2	30.2
	2013	36.5	33.7	35.0	32.4
	2014	45.1	41.5	44.1	40.5
	2015	31.9	29.9	31.5	29.5
	2016	27.8	26.6	27.8	26.6
	2012-2016	**34.9**	**32.7**	**33.9**	**31.8**
	2009-2016	**36.8**	**34.7**	**34.9**	**32.8**

[1] The nodal prices for Clifty and Kyger Creek from 2009 to 2015 represents OVEC node and represents the 8760 hour nodal average. PJM updated its LMP Bus Model on Dec 9, 2015 and added CLFTY and KYGER nodes. 2016 represents average of CLFTY and KYGER nodal prices.

Source: SNL Financial

Q. IS THE IMPACT OF CHANGES IN THE GENERATION MIX IN PJM REFLECTED IN THE IMPLIED HEAT RATE?

A. Yes, but great care must be exercised when using implied heat rates in power markets with substantial coal generation. The implied heat rate is calculated as the ratio of power to gas prices. It is a commonly used metric and is often used as a back of the envelope forecasting approach – i.e. price change of gas times implied heat rate is price change in power. The implied heat rate can be used to calculate the spark spread for gas powerplants (i.e., the difference between the costs of operating a gas plant and the market price), and if gas is on the margin, the addition of more thermally efficient powerplants can lower the implied heat rate. Implied heat rates [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

Exhibit 35

[BEGIN CONFIDENTIAL] [redacted])

	Energy Source/ Gas Source	AEP-Dayton Hub- All-hour Energy Price	Dominion South Gas Price	Market Implied Heat Rate- All-hour
Year	**Source**	**(Nom$/MWh)**	**Nom$/MMBtu**	**Btu/kWh**
2012	Historical/Historical	31.2	2.95	10,604
2013	Historical/Historical	35.0	3.69	9,491
2014	Historical/Historical	44.1	3.47	12,704
2015	Historical/Historical	31.5	1.67	18,884
2016	Historical/Historical	27.8	1.68	16,592
2017	Forwards/Futures	31.9	2.49	12,808
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average (2012-2016)		**33.9**	**2.7**	**12,614**
[redacted]		[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

Q. HOW DOES YOUR 2017 TO 2026 ELECTRICAL ENERGY PRICE FORECAST COMPARE TO 2016 PRICES?

A. The 2017 to 2026 nominal average of [BEGIN CONFIDENTIAL] [redacted] than the 2016 price. The 2026 nominal average of [redacted] than the 2016 price of $27.8/MWh. In all forecast years, prices are [redacted]. [END CONFIDENTIAL]

Q. WHAT ARE THE FORWARD ELECTRICAL ENERGY PRICE TRENDS?

A. Wholesale forward prices are available from the Intercontinental Exchange ("ICE")[27] through December 31, 2021 for energy. In 2017, the forward price of $31.9/MWh is very similar to the ICF forecast of [BEGIN CONFIDENTIAL] [redacted] By 2021, the forwards for all-hours AEP-Dayton Hub prices slightly decrease to $29.2/MWh and is [redacted] my forecast (see Exhibit 36). [END CONFIDENTIAL] However, the liquidity of the forward price is very limited past the first year of reporting, and provide only very limited information about market opinion. It can also be hard to trade in illiquid markets where any sizable position (i.e. buy or sell) actually changes the prices, and reported prices are often based on bids and asks rather than transactions. Also, forwards are very volatile and follow spot prices. In the beginning of 2016, the 2017 futures prices

[27] Intercontinental Exchange is a leading network of regulated exchanges and clearinghouses for financial and commodity markets.

was as low as $29.6/MWh and by the end of the year the price was high as $34/MWh.[28] Thus, I did not adopt the forward electrical energy prices.

Exhibit 36
AEP-Dayton Hub Forward Electrical Energy Prices ($/MWh)

Source	Year	AEP-Dayton Hub	AEP-Dayton Hub
		All-Hours Energy Price (2016$/MWh)	All-Hours Energy Price (Nom$/MWh)
Forward	2017	31.2	31.9
	2018	29.0	30.3
	2019	27.7	29.5
	2020	26.9	29.3
	2021	26.3	29.2
	Average 2017-2021	**28.2**	**30.0**

Source: SNL Financial; forwards reflect an annual average over trade dates of 12/1/16 to 12/31/16

[28] According to SNL Financial, the futures price of $29.6/MWh occurred on February 24, 2016 and the high futures price of $34/MWh occurred on December 28, 2016.

IX. POWER PLANT DISPATCH AND REALIZED ELECTRICAL ENERGY PRICES

Q. WHY ARE YOU FORECASTING DISPATCH AND REALIZED ELETRICITY PRICES?

A. If the net margins of the powerplants are positive, then the costs of power from the powerplants is less than the costs of power from the market place, and vice versa. In order to calculate net margins, I first need to calculate plant dispatch and realized prices.

Q. WHAT WAS THE HISTORIC DISPATCH OF CLIFTY CREEK AND KYGER CREEK?

A. Historically, over the 2012 to 2016 period, Clifty Creek and Kyger Creek average utilization[1] levels averaged 53.6%. Kyger Creek utilization[1] was 54.8% and Clifty Creek utilization[1] was 52.3%. Utilization is highly correlated to Henry Hub natural gas prices (e.g., 86% correlation coefficient over the 2012 to 2016 period). In 2012 to 2014 average plant utilization was high at 57.1% due to high gas prices but dropped in 2015-2016 to 48.3% due to lower market gas prices.

Exhibit 37
Historical Capacity Factors for the OVEC Plants (%)

Year	Kyger Creek	Clifty Creek
2011	74%	74%
2012	54%	55%
2013	59%	53%
2014	63%	58%
2015	42%	50%
2016[1]	55%	45%
Average (2011-2016)	**58%**	**56%**

Source: SNL Financial
[1] 2016 Capacity Factor is average of Jan - Nov 2016

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK DISPATCH?

A. Between 2017 and 2040, I forecast the average plant utilization rates will be [BEGIN CONFIDENTIAL] [redacted] [redacted] [END CONFIDENTIAL] The [redacted] natural gas and electrical energy prices, the impact of retirements, growing demand, and the lack of new coal power plant construction.

Plant dispatch forecasts vary over time. [BEGIN CONFIDENTIAL] [redacted] Dispatch over the 2030-2040 time period is [redacted] by potential national CO_2 emission regulations. [redacted]

[redacted] on average.

[END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 38

[redacted]

Delivery Period	**Kyger Creek (%)**	**Clifty Creek (%)**
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	75%
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

1) [redacted]
2) [redacted]
[redacted]

[END CONFIDENTIAL]

Q. WHAT IS YOUR FORECAST OF REALIZED PRICES DURING HOURS OF DISPATCH?

A. Kyger Creek and Clifty Creek will dispatch more in hours with higher prices, and hence, the average realized price of the plants should be higher than the all-hours nodal average – i.e., the price realized in the hours the plant is operated is higher than the all-hour market price average. Over the 2017 to 2026, I forecast the average realized energy prices will be [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] Realized prices are only slightly higher due to the strong dispatch of both plants.

[BEGIN CONFIDENTIAL] Exhibit 39

[redacted]

Delivery Period	AEP-Dayton	Kyger Creek		Clifty Creek	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1) [redacted]
2) [redacted]
[redacted]

[END CONFIDENTIAL]

X. ELECTRICITY PRICE PROJECTIONS – CAPACITY PRICES AND FIRM POWER PRICES

Q. HOW ARE ICF'S 2017-2020 CAPACITY PRICE FORECASTS FOR RTO DEVELOPED?

A. PJM capacity prices for January 1, 2017 to May 31, 2020 reflect actual auction results (blending auction capability year results into calendar years results) for the PJM RTO sub-regions. The capacity price across this large PJM sub-region reflects the auction cleared price for all those LDAs that did not separate in price during the auction process. These capacity prices come directly from PJM's BRA results.

Q. HOW ARE CAPACITY PRICES PROJECTED FOR 2020 TO 2040?

A. ICF projects PJM capacity prices for June 1, 2020 to May 31, 2040 using our fundamentals-based projections. ICF uses its IPM model which calculates demand and supply for capacity. Demand equals the zonal resource adequacy need for capacity expressed using planning reserve margin targets. Supply is each unit's net capacity cost, which is the unit's cash-going forward fixed costs less energy market earnings. The model can retire, mothball, and build power plants to meet reserve margin targets. The model can also transmit firm capacity across zones using a separate characterization of transmission. Specifically, the lower transmission limits are N-1 rather than the N-0 used for electrical energy. The marginal costs of meeting the demand for capacity equals the capacity price. This calculation accounts for all earnings in all periods for new units built by the model.

Q. WHAT ARE THE KEY ELEMENTS OF ICF'S CAPACITY PRICE FORECAST?

A. In the near term, capacity prices are set at levels that prevent excessive withdrawal of existing units from the market and in the longer run the price is set at levels needed to support new builds.

Q. WHAT ARE YOUR CAPACITY PRICE FORECASTS?

A. ICF's capacity price forecasts are shown in Attachment III and Exhibit 40. I forecast that the capacity price [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Regarding the already determined capacity prices, the RTO capacity price for delivery years 2017[30] to 2019 averages \$42.9/kW-yr in real 2016 dollars, and \$44.8kW-yr in nominal dollars.

---

29 [redacted]

[30] Calendarization of 2016/2017, 2017/2018 and 2018/2019.

[BEGIN CONFIDENTIAL] Exhibit 40

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]

[redacted]

1) [redacted]

2) [redacted]

[END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 41

[redacted]

[END CONFIDENTIAL]

Q. WHY ARE CAPACITY PRICES INCREASING?

A. As noted, in the near term, the capacity price is set at the level that prevents excessive mothballing and retirement. Over time, as a result of retirements and net load growth (net of demand resources such as interruptible load), there is a need for new units and their costs net of energy earnings set the capacity prices. Also, over time, as more new combined cycles are added, the energy earnings available to incremental units decreases, and hence, capacity prices rise. In addition, capacity prices rise due to general inflation.

Q. ARE THERE OTHER REASONS FOR CAPACITY PRICES TO INCREASE TO YOUR ESTIMATED NET COST OF A NEW ENTRANT?

A. Yes. As discussed earlier, the capacity performance rules are supposed to set the penalty rate such that plants are indifferent between bidding net CONE times the balancing ratio (typically 80 to 90 %) or being energy only. Put another way, there is supposed to be an opportunity cost to providing capacity. However, PJM has not properly set the penalty rate – it is too low because the expected hours of penalty are too high. When this happens the penalty is too low because the penalty is the ratio of the net CONE times balancing ratio divided by the hours. PJM is required to report this year to FERC on what the hours of expected penalty should be as FERC concluded there is not an adequate basis for the estimate used (the current estimate for the RTO of 30 hours is based on a single year), and PJM itself has released historical data[31] showing the hour estimate is too high. Once this is fixed, prices will be more stable and close to net CONE.

Q. WHAT ARE FIRM ALL-HOUR PRICES?

A. Firm unit contingent all-hour prices combine energy and capacity into a single $/MWh price_by amortizing capacity payment over all the hours. As shown below in Exhibit 42, the average firm price between 2017 and 2040 is [BEGIN CONFIDENTIAL] [redacted]. In the near term, the average forecast price over the 2017 to 2026 time period at [redacted] than the recent historical average of $37.1/MWh over the 2012 to 2016 time period. In real 2016 dollars, 2017 to 2026 firm all-hour prices are [redacted] The 2017 – 2026 firm all-hour price will be [redacted] 2016 levels. [END CONFIDENTIAL]

---

[31] http://www.pjm.com/-/media/committees-groups/committees/elc/postings/performance-assessment-hours-2011-2014-xls.ashx. See discussion elsewhere in this document.

[BEGIN CONFIDENTIAL] Exhibit 42

[redacted]

Delivery Period	Source	AEP-Dayton All-hour Firm Price	
		Nom $/MWh	2016 $/MWh
2012	Historical	33.5	35.5
2013	Historical	36.0	37.5
2014	Historical	47.6	48.8
2015	Historical	37.0	37.5
2016	Historical	31.6	31.6
[redacted]	[redacted]	[redacted]	[redacted]
Average (2012-2016)		**37.1**	**38.2**
[redacted]		[redacted]	[redacted]
		[redacted]	[redacted]
		[redacted]	[redacted]

[END CONFIDENTIAL]

Q WHAT IS YOUR ESTIMATE OF ANNUAL WHOLESALE ELECTRICITY PRICE VOLATILITY?

A. Power prices have exhibited very significant annual volatility (i.e., variance). I anticipate this significant annual price volatility will continue around the expected value. I focus on one measure of annual volatility namely the range of annual all-hour electrical energy prices for the AEP Dayton Hub. Over the 2012-2016 five year period, the range was $27.8/MWh to $44.1/MWh or $16/MWh. This range is 48% of the average price, and hence, indicates high volatility. When I factor in capacity prices, the firm price range over the same period was $31.6/MWh to $47.6/MWh and range was $16/MWh or 43% of the average. The high volatility is driven in large part by variation in weather conditions (weather was warm in the winters of 2012 and 2016 while the winters were cold in 2014 and 2015), the lack of storage, natural gas price volatility, variation in generation supply costs, industry cycles and changes in FERC regulations. Greater reliance on spot natural gas will increase spot power price volatility, especially in situations where natural gas production and delivery infrastructure falls behind increased natural gas consumption.

XI. PROJECTIONS OF REVENUES AND GROSS MARGINS

Q. WHAT IS YOUR PROJECTION OF REVENUES FOR CLIFTY CREEK AND KYGER CREEK?

A. Over the 2017 to 2040 period, in nominal dollars, I forecast the average revenues for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] The average revenue rate including all revenue streams will be [redacted] (see Exhibit 43 which also includes gross margins). [redacted] growth rate in revenues between 2018 and 2039 is [redacted]. [END CONFIDENTIAL]

Revenues forecasts, like dispatch forecasts, show variation over time. Over the 2017-2026 period, I forecast the average revenues for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] The average revenue rate including all revenue streams will be [redacted] [END CONFIDENTIAL].

32 [redacted]

[BEGIN CONFIDENTIAL] Exhibit 43

[redacted]

Kyger Creek

Delivery Period	Energy Revenue	Capacity Revenue	Ancillary Revenue	Fuel Cost	Other Expenses	Gross Margin
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Clifty Creek

Delivery Period	Energy Revenue	Capacity Revenue	Ancillary Revenue	Fuel Cost	Other Expenses	Gross Margin
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK GROSS MARGINS?

A. Gross margin is revenues less fuel and other short run variable costs including emission allowance costs. Over the 2017 to 2040, in nominal dollars, I forecast the average annual gross margins for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] Gross margins average [redacted] On average, the plants receive gross margins of [redacted] [END CONFIDENTIAL]

In the long term, plant specific parameters are affected by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Revenues increase faster than costs and margins increase much faster than revenues – i.e. there is operating leverage.

Over the 2027 to 2040 period, I forecast annual average gross margins for the two plants will be [BEGIN CONFIDENTIAL] [redacted] On average, the plants receive gross margins of [redacted] growth rate for gross margins between 2027 and 2040 is [redacted] [END CONFIDENTIAL].

XII. PROJECTIONS OF DEMAND CHARGES AND NET MARGINS

Q. WHAT IS THE FORECAST OF OVEC DEMAND CHARGES?

A. OVEC demand charges are paid pursuant to a contract originally entered in to by 12 utilities in the 1952. As discussed, the Clifty Creek and Kyger Creek powerplants were built during the Cold War to provide power for the production of enriched uranium in the Portsmouth Ohio. The forecast of OVEC's projected demand charges was provided to me and are:

- **Total Costs** - Between 2017 and 2040, the total demand charge averages approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on a levelized or annuity basis. This can be further broken down into two parts.
    - **Recovery of Past Capital Cost** – Between 2017 and 2040, recovery of and on previously invested capital comprises [BEGIN CONFIDENTIAL] [redacted] END CONFIDENTIAL]
    - **Cash Going Forward Cost** - Between 2018 and 2040, cash going forward costs i.e. fixed annual O&M and property taxes, incremental maintenance capital expenditures, G&A averages [BEGIN CONFIDENTIAL] [redacted] END CONFIDENTIAL]

Over time, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. HOW SHOULD SUNK COSTS BE TREATED?

A. Society's economic value[33] is maximized by maximizing the cash going forward net margins and treating previously incurred capital investment as sunk – i.e., by not including sunk costs. When I conduct this economic analysis, I conclude that the OVEC plants should continue to operate.

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING CASH GOING FORWARD COSTS?

A. Net margins [redacted] value basis. This means the plants' power are expected to cost less than relying on market, and should continue to operate. In addition, the plants' power costs have less volatility than market purchases and

---

[33] Assuming efficient pricing.

the power supply from the plant provides a hedge against higher prices. In the Base Case, [BEGIN CONFIDENTIAL], the present value of the plant's [redacted] [END CONFIDENTIAL] If the plants' cash going forward costs are negative and stay negative, the plant is taken off line in that year and the cash going forward costs are zeroed out.

34 [redacted]

[BEGIN CONFIDENTIAL] Exhibit 44

[redacted]

Delivery Period	Gross Margin	Demand Charges		Net Margins	
		Fixed Costs	Sunk Costs	With Total Demand Charges	Excluding Sunk Costs
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]	[redacted]

[redacted] 0 [redacted]

[END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 45

[redacted]

Delivery Period	Gross Margin	Demand Charges		Net Margins	
		Fixed Costs	Sunk Costs	With Total Demand Charges	Excluding Sunk Costs
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

In Exhibit 46, we shown the net present value of pre-tax net margins across the Base and four different sensitivity cases.

- **Base Case**: is ICF's expected view on key input assumptions such as natural gas prices, coal prices, national CO_2 regulations and PJM demand.
- **No National CO_2 Regulations Case**: is the same as the Base Case with the exception of no national CO_2 regulations, and that natural gas prices are adjusted by this impact.
- **Hypothetical Lower OVEC Fixed Costs Case**: OVEC's estimated fixed costs are adjusted downwards to illustrate sensitivity to this parameter.
- **Higher Gas Prices - AEO 2017 Reference Case**: is the same as the Base Case with the exception of Henry Hub gas price projections; this case uses the DOE EIA AEO 2017 Reference Case forecast.
- **Combination of All Three Sensitivities Case:** reflects all changes in the three sensitivity cases listed above, where the gas prices are from EIA AEO 2017 Reference Case, fixed costs reflect a hypothetically lower level, and no national CO_2 regulations are considered.

[BEGIN CONFIDENTIAL] **Exhibit 46**

[redacted]

Case	Sunk Costs Included	2017-2040
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

Exhibit 47

[redacted]

Case	Sunk Costs Included	2017-2040
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

The value becomes [redacted] in the following sensitivity cases.

- **Hypothetical Lower OVEC Fixed Costs** - If the costs for the plants [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] We have not reviewed the plant's costs in detail.
- **Higher Gas Prices –AEO 2017 Reference Case** - If natural gas prices were [BEGIN CONFIDENTIAL] [redacted] the US EIA Base Case[35] gas prices, [redacted], [redacted] [END CONFIDENTIAL]
- **No National CO_2 Regulations** - If no national CO_2 program is implemented in the late 2020s and 2030s, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]
- **Combination of All Three Sensitivities Case** - The combination of the above three sensitivity results in the net margin [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[35] US EIA's "*Annual Energy Outlook 2017*"

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING TOTAL DEMAND CHARGES (INCLUDING SUNK COSTS)?

A. Including all of the demand charges[36] and using the Base Case results, the OVEC plants' net margins are [BEGIN CONFIDENTIAL] [redacted] on a net present value basis [redacted] The net margin [redacted]

[END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] [redacted] (the same cases as discussed above):

- **"Hypothetical" Lower OVEC Fixed Costs** – If hypothetically the costs for the plants were [redacted]

---

[36] On a levelized basis, all demand charges would average [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in nominal dollars.

- **Higher Gas Prices –AEO 2017 Reference Case** – If gas prices were [redacted]
- **No National CO_2 Regulations** – If no national CO_2 program is implemented in the late 2020s and 2030s[redacted]
- **Combination of All Three Sensitivities Case** – The combination of the three above sensitivity cases results in the [redacted] [END CONFIDENTIAL]

Q. WHAT IS YOUR ASSESSENT OF THE PLANT'S ANNUAL COST VOLATILITY?

A. Annual wholesale market price volatility is [BEGIN CONFIDENTIAL] [redacted] than volatility in the costs of Clifty Creek and Kyger Creek. The range of average delivered coal cost over the 2012 to 2016 was \$2.0/MMBtu to \$2.5/MMBtu or \$0.4/MMBtu. This was [redacted] of the average. Total costs ranged from [redacted]. This [redacted] of the average. This compares to 43% for the firm power price – i.e., the volatility of the market is approximately[redacted]. [END CONFIDENTIAL]

XIII. CONCLUSIONS

WHAT ARE YOUR CONCLUSIONS?

A. My conclusions address electricity market price forecasts, powerplant operational and financial performance forecasts, demand charges and net margins, and annual power price and annual cost volatility.

XIII.1 Electricity Market Prices

I conclude that firm all-hour wholesale electricity prices are on [redacted] trajectory relative to 2016 prices. Between 2018 and 2039, in the Base Case, firm prices [redacted] by [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

This forecast is supported by:

- **Unsustainably Extreme Conditions** - The winter of 2015/2016 was the warmest in US history, and oil prices fell from $108/barrel in early 2014 to less than $30/Barrel in early 2016.
- **Historically Low Prices** - AEP Dayton electrical energy prices were the lowest since 2005, and Henry Hub gas prices were the lowest since 1999. Dominion South gas prices were the lowest.
- **Evidence of Non-sustainability** – Between 2014 and 2016, US drilling for oil and gas dropped 75% and there were over 100 bankruptcies in mid and small oil and gas producers.

- **Price Increases During 2016** – Many spot and forward prices increased over the course of 2016 though some fell back in the face of another bout of record warm weather in early 2017. For example:
  - In the beginning of 2016, the 2017 futures price for AEP Dayton was as low as \$29.6/MWh and by the end of the year the price was high as \$34/MWh (+15%).[37]
  - In the first ten months of 2016, Dominion South prices averaged \$1.31/MMBtu, which was a discount to Henry Hub of \$1.09/MMBtu. Between November 2016 and January 2017, Dominion South prices averaged \$2.63/MMBtu, an increase of 100% relative to the first ten months of 2016.
  - In March 2016, Henry Hub spot prices averaged \$1.72/MMBtu; this was the lowest monthly average since December 1998. Between November 2016 and January 2017, Henry Hub spot prices averaged \$3.15/MMBtu which is 50% above prices in the same time period one year earlier and 83% above March 2016. They only returned to low levels in the face of another record warm early 2017.
  - The 2017 futures price for delivery to Henry Hub price increased significantly over the last 12 months. 2017 futures bottomed at \$2.47/MMBtu on February 25, 2016, and peaked at \$3.7/MMBtu

[37] According to SNL Financial, the futures price of \$29.6/MWh occurred on February 24, 2016 and the high futures price of \$34/MWh occurred on December 28, 2016.

on December 28, 2016 – that is in ten months the price increased 50%.

XIII.2 Powerplant Operational and Financial Performance

[redacted] This forecast reflects two recent regulatory developments favorable to the economics of Clifty Creek and Kyger Creek. First, it is now very likely that potential CO_2 emission and other regulations adverse to OVEC's plants will be significantly deferred compared to national CO_2 controls starting in 2022 as per the CPP. Second, PJM is implementing capacity market reforms related to the PJM capacity market order in 2015. [redacted] gross and net margins relative to a non-reformed capacity market in a CPP regulated situation.

XIII.3 Demand Charges and Net Margin

Demand charges grow [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

The OVEC plants provide electricity at a going forward cost [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] This is in part because they access low cost coal from the Ohio River, while the market increasingly relies on higher cost sources of power. This occurs starting in 2019 when the market recovers from 2016 depressed levels. This conclusion becomes stronger if any of three things occur – lower non fuel fixed costs, US EIA gas forecasts turn out to be more accurate, or if national CO_2 regulations, already assumed to be delayed, are not assumed even in the 2030s.

When sunk costs are included, the OVEC plants provide electricity at a cost [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

XIII.4 Price and Cost Volatility

The volatility of market power is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] than the volatility of Clifty Creek and Kyger Creek's power costs – approximately [redacted]. Using historical statistics, the five year range[38] is 43% of the average for market firm power and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] I expect this relationship to continue. Natural gas is one of the most volatile commodities and partly sets market prices while the coal and fixed costs of Clifty Creek and Kyger Creek are much less volatile. Lower volatility all else equal is preferred but I do not opine on the trade-offs between the two.

[38] All-hours firm price historical data for 2012-2016 has a range of $16/MWh, with a minimum price of $31.6/MWh in 2016 and maximum price of $47.6/MWh in 2014. Average all-hour firm price over 2012-2016 is $37.1/MWh.

I have not conducted a detailed history of the contract, OVEC's complex regulatory history, and am not opining on how sunk costs should be treated with regard to rate recovery. However, I note an argument in support of Duke Energy Ohio's request is that the unconventional and unique power supply agreement is the legacy of prudent decisions made long before deregulation. Indeed, it is my understanding that the decision was primarily a response to an urgent national need for the industry to work collaboratively on an important matter of national defense.

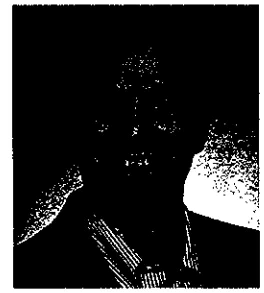
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. I also reserve the right to supplement my testimony.

ATTACHMENT I

Judah L. Rose ICF

Senior Vice President, Managing Director



Education

- M.P.P., John F. Kennedy School of Government, Harvard University, 1982
- S.B., Economics, Massachusetts Institute of Technology, 1979

Awards and Recognition

- One of ICF's Distinguished Consultants, an honorary title given to only three of ICF's 5,000 employees

Experience Overview

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF. He Chairs its Energy Advisory Services Line of Business and works closely with its ICF's Wholesale Power practice and Chairs its Energy Advisory Services Line of Business.

Accomplishment Highlights

- Close to 40 years of experience in the energy industry
- Testimony in over 130 instances in scores of state, federal, international, and other legal proceedings
- Frequent counselor on restructuring and financing of new and existing power plants

Mr. Rose has approximately 40 years of experience in the energy industry including in electricity market design, power generation, power fuels – coal, natural gas, renewables, environmental compliance, planning, finance, forecasting, and transmission. His clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, consumers and Independent Power Producers. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 5,000 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative.

Mr. Rose frequently provides expert testimony and litigation support. He has provided testimony in over 130 instances in 45 venues including scores of state, federal, international, and other legal proceedings. Mr. Rose has testified in over 24 states and provinces, at the Federal Energy Regulatory Commission, in numerous court settings and internationally.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community in restructuring and financing.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. He has also appeared in TV interviews.

Selected Press Interviews

Television

- "The Most With Allison Stewart," MSNBC, "Blackouts in NY and St. Louis & ongoing Energy Challenges in the Nation," July 25, 2006

- CNBC Wake-Up Call, August 15, 2003
- Wall Street Journal Report, July 25, 1999
- Back to Business, CNBC, September 7, 1999

Journals:
- Electricity Journal
- Energy Buyer Magazine
- Public Utilities Fortnightly
- Power Markets Week

Magazines:
- Business Week
- Power Economics
- Costco Connection

Newspapers:
- Denver Post
- Rocky Mountain News
- Financial Times Energy
- LA Times
- Arkansas Democratic Gazette
- Galveston Daily News
- The Times-Picayune
- Pittsburgh Post-Gazette
- Power Markets Week

Wires:
- Associated Press
- Bridge News
- Dow Jones Newswires

Testimony

131. Affidavit, In Answer to Complaint of Next Era and PSEG Companies, FERC Docket No. EL16-93-000, Testimony on New Gas Pipelines, and Wholesale Gas and Power Market Design, July 28, 2016. On behalf of Eversource.
130. Rebuttal Testimony, Support for an Electric Security Plan Filing, on behalf of Ohio Edison Company, The Cleveland Electric illuminating Company, The Toledo Edison Company, Case No. 14-1297-EL-SSO, October 20, 2015.
129. Demand Resource Pricing Testimony on behalf of P3, Docket ER15-852-000, February, 13, 2016
128. Damages Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, January 5, 2015.
127. Responsive Testimony of Judah L. Rose on Behalf of Oklahoma Energy Results, LLC December 16, 2014, CAUSE NO. PUD 201400229
126. Rebuttal Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, November 26, 2014.

125. Statement of Opinions on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, October 30, 2014.
124. Direct Testimony, CO_2 price forecasts provided to IPL for use in their compliance analysis, as well as, support for the probabilities assigned to the Coal Combustion Residuals ("CCR"), 316 (b) and Effluent Limitation Guidelines ("ELG") regulations for use in IPL analysis in support of their Compliance Project, Indianapolis Power & Light Company, IURC Cause No. 44540, October 14, 2014.
123. Direct Testimony, Support for an Electric Security Plan Filing, Ohio Edison Company (FirstEnergy), August 4, 2014.
122. Rebuttal Testimony, Valuation of Mad River Power Plant, FirstEnergy, February 27, 2014.
121. Expert Report, Computation of Future Damages, Breach of Wolf Run Coal Sales Agreement, prepared for Meyer, Unkovic, and Scott, LLP, filed February 12, 2014.
120. Supplemental Direct Testimony of Judah Rose on behalf of National Grid and Northeast Utilities, Petition of New England Power Company d/b/a/ National Grid for Approval to Construct and Operate a New 345 kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69J, August 8, 2013.
119. Rebuttal Testimony of Judah Rose on Behalf of Monongahela Power Company, *The Potomac Edison Company, Petition for Approval of a Generation Resource* Transaction and Related Relief, Case No. 12-1571 – E – PC, May 17, 2013.
118. Direct Testimony of Judah Rose on behalf of New England Power Company d/b/a National Grid before the Commonwealth Of Massachusetts Energy Facilities Siting Board and Department Of Public Utilities, Petition of New England Power Company d/b/a National Grid for Approval to Construct and Operate a New 345kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69, Docket EFSB 12-1/D.P.U. 12-46/47, November 21, 2012.
117. Direct Testimony for the Narragansett Electric Company d/b/a National Grid (Interstate Reliability Project), Before the State of Rhode Island Public Utilities Commission, Energy Facility Siting Board ("Siting Board") Notice of Designation to Public Utilities Commission ("PUC") to Render an Advisory Opinion on need and cost-justification for Narragansett Electric d/b/a National Grid's proposal to construct and alter major energy facilities in RI, the "Interstate Reliability Project", RIPUC Docket No. 4360, November 21, 2012
116. Sur-Surrebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, September 21, 2012.
115. Rebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, July 30, 2012.

114. Direct Testimony, The Connecticut Light & Power Company, Application for a Certificate of Environmental Compatibility and Public Need for the Connecticut Portion of the Interstate Reliability Project that traverses the municipalities of Lebanon, Columbia, Coventry, Mansfield, Chaplin, Hampton, Brooklyn, Pomfret, Killingly, Putnam, Thompson, and Windham, which consists of (a) new overhead 345-kV electric transmission lines and associated facilities extending between CL&P's Card Street Substation in the Town of Lebanon, Lake Road Switching Station in the Town of Killingly, and the Connecticut/Rhode Island border in the Town of Thompson; and (b) related additions at CL&P's existing Card Street Substation, Lake Road Switching Station, and Killingly Substation, Docket No. 424, July 17, 2012.
113. Direct Testimony, Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, February 9, 2012.
112. Rebuttal Testimony, Otter Tail Power Company, Before the Office of administrative Hearings, for the Minnesota Public Utilities Commission, In The Matter of Otter Tail Power Company's Petition for an Advance Determination of Prudence for its Big Stone Air Quality Control System Project, September 7, 2011.
111. Rebuttal Testimony, on behalf of Arizona Public Service, In the Matter of the Application of Arizona Public Service Company for Authorization for the Purchase of Generating Assets from Southern California Edison, and for an Accounting Order, Docket No. E-01345A-10-0474, June 22, 2011.

110. Direct Testimony, Duke Energy Ohio, Inc., Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service, Case No. 11-XXXX-EL-SSO. Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. Case No. 11-XXXX-EL-ATA. Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. Case No. 11-XXXX-EL-UNC, June 20, 2011.
109. Direct Testimony, Manitoba Hydro Power Sales Contracting Strategy, U.S. Power Markets, Manitoba Hydro Drought Risks, Modeling, Forecasting and Planning, Selected Risk and Financial Issues, Governance, Trading and Risk Related Comments Before the Public Utilities Board of Manitoba, February 22, 2011.
108. Sur-rebuttal Testimony - Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2010-0356, January 12, 2011.
107. Rebuttal Report Concerning Coal Price Forecast for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed December 6, 2010.

106. Direct Testimony of Judah Rose on behalf of Duke Energy Ohio In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service, Case No. 10-2586-EL-SSO, filed November 15, 2010.
105. Updated Forecast, Coal Price Report for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed October 18, 2010.
104. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 29, 2010.
103. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 16, 2010.
102. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line Oklahoma LLC to conduct Business as an Electric Utility in the State of Oklahoma, Cause No.PUD 201000075, July 16, 2010.
101. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line LLC for a Certificate of Public Convenience and Necessity to Operate as an Electric Transmission Public Utility in the State of Arkansas, Docket No. 10-041-U, June 4, 2010.
100. Supplemental Testimony on Behalf of Entergy Arkansas, Inc., In the Matter of Entergy Arkansas, Inc., Request for a Declaratory Order Approving the Addition of the Environmental Controls Project at the White Bluff Steam Electric Station Near Redfield, Arkansas, Docket No. 09-024-U, July 6, 2009.
99. Rebuttal Testimony on Behalf of TransEnergie, Canada, Province of Quebec, District of Montreal, No.: R-3669-2008-Phase 2, FERC Order 890 and Transmission Planning, July 3, 2009.
98. Sur-rebuttal Testimony - Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, before the Missouri Public Service Commission, In the Matter of the Application of KCP&L GMO, Inc. d/b/a KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2009-0090, April 9, 2009.
97. Hawaii Structural Ironworkers Pension Trust Fund v. Calpine Corporation, Case No. 1-04-CV-021465, Assessment of Calpine's April 2002 Earnings Projections, March 25, 2009.
96. Coal Price Report for Harrison Coal Plant, Allegheny Energy Supply Company, LLS and Monongahela Power Company versus Wolf Run Mining Company, Anker Coal Group, etc., Civil Action. No. GD-06-30514, In the Court of Common Pleas, Allegheny County, Pennsylvania, February 6, 2009.
95. Supplemental Direct Testimony of Judah Rose, on behalf of Southwestern Electric Power Company, In the Matter of the Application of Southwestern Electric Power Company for Authority to Construct a Natural-Gas Fired Combined Cycle Intermediate Generating Facility in the State of Louisiana, Docket No. 06-120-U, December 9, 2008.

94. Rebuttal Testimony of Judah Rose on behalf of Kelson Transmission Company, LLC re: Application of Kelson Transmission Company, LLC For A Certificate of Convenience and Necessity For the Amended Proposed Canal To Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, And Orange Counties, SOAH Docket No. 473-08-3341, PUCT Docket No. 34611, October 27, 2008.
93. Testimony of Judah Rose, on behalf of Redbud Energy, LP, in Support of Joint Stipulation and Settlement Agreement, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of the Purchase of the Redbud Generating Facility and Authorizing a Recovery Rider, Cause No. PUD 200800086, September 3, 2008.

92. Direct Testimony of Judah L. Rose on behalf of Duke Energy Carolinas, In the Matter of Advance Notice by Duke Energy Carolinas, LLC, of its Intent to Grant Native Load Priority to the City of Orangeburg, South Carolina, and Petition of Duke Energy Carolinas, LLC and City of Orangeburg, South Carolina for Declaratory Ruling With Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority, Docket No. E-7, SUB 858, August 15, 2008.
91. Affidavit filed on behalf of Public Service of New Mexico pertaining to the Fuel Costs of Southwest Public Service for Cost-of-Service and Market-Based Customers, August 11, 2008.
90. Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio, Inc., Before the Public Utilities Commission of Ohio, In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan, July 31, 2008.
89. Rebuttal Testimony, Judah L. Rose on Behalf of Duke Energy Carolinas, in re: Application of Duke Energy Carolinas, LLC for Approval of Save-A-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket No. E-7, Sub 831, July 21, 2008.
88. Updated Analysis of SWEPCO Capacity Expansion Options as Requested by Public Utility Commission of Texas, on behalf of SWEPCO, June 27, 2008.
87. Direct Testimony of Judah L. Rose on Behalf of Nevada Power/Sierra Pacific Electric Power Company, Docket No. 1, Public Utilities Commission of Nevada, Application of Nevada Power/Sierra Pacific for Certificate of Convenience and Necessity Authorization for a Gas-Fired Power Plant in Nevada, May 16, 2008.
86. Rebuttal Testimony of Judah L. Rose on Behalf of the Advanced Power, Commonwealth of Massachusetts, Before the Energy Facilities Siting Board, Petition of Brockton Power Company, LLC, EFSB 07-7, D.P.U. 07-58 & 07-59, May 16, 2008.
85. Supplemental Rebuttal Testimony on Commissioner's Issues of Judah L. Rose for Southwestern Electric Power Company, on behalf of Southwestern Electric Power Company, PUC Docket No. 33891, Public Utilities Commission of Texas, May 2008.
84. Supplemental Direct Testimony on Commissioners' Issues of Judah Rose for Southwestern Electric Power Company, for the Application of Southwestern

Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas, SOAH Docket No. 473-07-1929, PUC Docket No. 33891, Public Utility Commission of Texas, April 22, 2008.

83. Rebuttal Testimony of Judah Rose, In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008.
82. Rebuttal Report of Judah Rose, Ohio Power Company and AEP Power Marketing Inc. vs. Tractebel Energy Marketing, Inc. and Tractebel S.A. Case No. 03 CIV 6770, 03 CIV 6731 (S.D.N.Y.), January 28, 2008.
81. Proposed New Gas-Fired Plant, on behalf of AEP SWEPCO, 2007.
80. Rebuttal Report, Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 21, 2007.
79. Expert Report. Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 19, 2007.
78. Application of Duke Energy Carolina, LLC for Approval of Energy Efficiency Plan Including an Energy Efficiency Rider and Portfolio of Energy, Docket No. 2007-358-E, Public Service Commission of South Carolina, December 10, 2007.
77. Independent Transmission Cause No. PUD200700298, Application of ITC, Public Service of Oklahoma, December 7, 2007.
76. Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code š8-1-2.5-1, et. Seq. for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance With Ind. Code šš8-1-2.5-1 et seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the PowerShare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Cause Earnings and Expense Tests, Indiana Utility Regulatory Commission, Cause No. 43374, October 19, 2007.
75. Rebuttal Testimony, Docket No. U-30192, Application of Entergy Louisiana, LLC For Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery, October 4, 2007.
74. Direct Testimony of Judah Rose on Behalf of Tucson Electric Power Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, July 2, 2007.

73. Supplemental Testimony on behalf of Southwestern Electric Power Company before the Arkansas Public Service Commission, In the Matter of Application of Southwestern Electric Power Company for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation, and Maintenance of a Coal-Fired Base Load Generating Facility in the Hempstead County, Arkansas, dated June 15, 2007, Docket No. 06-154-U.
72. Rebuttal Testimony, Causes No. PUD 200500516, 200600030, and 20070001 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, June 2007.
71. Rebuttal Testimony on behalf of Duke Energy Indiana, IGCC Coal Plant CPCN, Cause No. 43114 before the Indiana Utility Regulatory Commission, May 31, 2007.
70. Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 2007.
69. Rebuttal Testimony on behalf of Florida Power & Light Company In Re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant, Docket No. 070098-EL, March 30, 2007.
68. Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 2007.
67. Direct Testimony for Southwestern Electric Power Company, Before the Louisiana Public Service Commission, Docket No. U-29702, in re: Application of Southwestern Electric Power Company for the Certification of Contracts for the Purchase of Capacity for 2007, 2008, and 2009 and to Purchase, Operate, Own, and Install Peaking, Intermediate and Base Load Coal-Fired Generating Facilities in Accordance with the Commission's General Order Dated September 20, 1983. Consolidated with Docket No. U-28766 Sub Docket B in re: Application of Southwestern Electric Power Company for Certification of Contracts for the Purchase of Capacity in Accordance with the Commission's 'General Order of September 20, 1983, February 2007.
66. Second Supplemental Testimony on Behalf of Duke Energy Ohio Before the Public Utility Commission of Ohio, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA, February 28, 2007.
65. Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, February 2007.
64. Supplemental Testimony on behalf of Duke Energy Carolinas before the North Carolina Utilities Commission in the Matter of Application of Duke Energy Carolinas, LLC for Approval for an Electric Generation Certificate of Public Convenience and Necessity to Construct Two 800 MW State of Art Coal Units for Cliffside Project, Docket No. E7, SUB790, December 2006.
63. Expert Report, Chapter 11, Case No. 01-16034 (AJG) and Adv. Proc. No. 04-2933 (AJG), November 6, 2006.
62. IGCC Coal Plant, Testimony on behalf of Duke Energy Indiana, Cause No. 43114, October 2006.

61. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106 OAL Docket No. PUC-1874-05, Supplemental Testimony March 20, 2006.
60. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Surrebuttal Testimony December 27, 2005.
59. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, November 14, 2005.
58. Brazilian Power Purchase Agreement, confidential international arbitration, October 2005.
57. Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.
56. Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.
55. Cost of Service and Fuel Clause Issues, Testimony on behalf of Public Service of New Mexico, FERC Docket No. EL05-151-000, September 15, 2005.
54. Cost of Service and Peak Demand, FERC, Responsive Testimony on behalf of Public Service of New Mexico, August 23, 2005, Docket No. EL05-19.
53. Prudence of Acquisition of Power Plant, Testimony on behalf of Redbud, September 12, 2005, No. PUD 200500151.
52. Proposed Fuel Cost Adjustment Clause, FERC, Docket Nos. EL05-19-002 and ER05-168-001 (Consolidated), August 22, 2005.
51. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU, FERC, Docket EC05-43-000, May 27, 2005.
50. New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.
49. Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.
48. New Air Emission Regulations and Investment in Coal Power Plants, supplemental testimony on behalf of PSI, January 21, 2005, Causes 42622 and 42718.
47. Damages Due to Rejection of Tolling Agreement Including Discounting, January 10, 2005, CONFIDENTIAL.
46. Discount rates that should be used in estimating the damages to GTN of Mirant's bankruptcy and subsequent abrogation of the gas transportation agreements Mirant had entered into with GTN, December 15, 2004. CONFIDENTIAL
45. New Air Emission Regulations and Investment in Coal Power Plants, testimony on behalf of PSI, November 2004, Causes 42622 and 42718.
44. Rebuttal Testimony of Judah Rose on behalf of PSI, "Certificate of Purchase as of yet Undetermined Generation Facility" Cause No. 42469, August 23, 2004.
43. Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, Mohave Coal Plant Economics, June 4, 2004.

42. Supplemental Testimony "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, May 20, 2004.
41. "Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Coal-Fired Generating Station," May 14, 2004.
40. "Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.
39. "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.
38. "Valuation of Selected MIRMA Coal Plants, Acceptance and Rejection of Leases and Potential Prejudice to Leasors" Federal Bankruptcy Court, Dallas, TX, March 24, 2004 CONFIDENTIAL.
37. "Certificate of Purchase as of yet Undetermined Generation Facility", Cause No. 42469 for PSI, March 23, 2004.
36. "Ohio Edison's Sammis Power Plant BACT Remedy Case", In the United States District Court of Ohio, Southern Division, March 8, 2004.
35. "Valuation of Power Contract," January 2004, confidential arbitration.
34. "In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, Coal-Fired and Gas-Fired Market Values, July 21, 2003.
33. "In the Supreme Court of British Columbia", July 8, 2003. CONFIDENTIAL
32. "The Future of the Mohave Coal-Fired Power Plant – Rebuttal Testimony", California P.U.C., May 20, 2003.
31. "Affidavit in Support of the Debtors' Motion", NRG Bankruptcy, Revenues of a Fleet of Plants, May 14, 2003. CONFIDENTIAL
30. "IPP Power Purchase Agreement," confidential arbitration, April 2003.
29. "The Future of the Mohave Coal-Fired Power Plant", California P.U.C., March 2003.
28. "Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL
27. "Power Purchase Agreement Valuation", Confidential Arbitration, October 2002.
26. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02."

25. "Cause No. 42200 - in support of PSI's petition for authority to recover through retail rates on a timely basis. Filed on 7/30/02."
24. "Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."
23. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002."
22. "Analysis of an IGCC Coal Power Plant", Minnesota state senate committees, January 22, 2002.
21. "Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002
20. "Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001
19. "The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000
18. "Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL
17. "Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL
16. Application of FirstEnergy Corporation for approval of an electric Transition Plan and for authorization to recover transition revenues, Stranded Cost and Market Value of a Fleet of Coal, Nuclear, and Other Plants, Before PUCO, Case No. 99-1212-EL-ETP, October 4, 1999 and April 2000.
15. "Issues Related to Acquisition of an Oil/Gas Steam Power plant in New York", September 1999 Affidavit to Hennepin County District Court, Minnesota
14. "Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages", Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.
13. "Power Prices." Testimony in confidential contract arbitration, July 1998.
12. "Horizontal Market Power in Generation." Testimony to New Jersey Board of Public Utilities, May 22, 1998.
11. "Basic Generation Services and Determining Market Prices." Testimony to the New Jersey Board of Public Utilities, May 12, 1998.
10. "Generation Reliability." Testimony to New Jersey Board of Public Utilities, May 4, 1998.
9. "Future Rate Paths and Financial Feasibility of Project Financing." Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.
8. "Stranded Costs of PSE&G." Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.
7. "Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code." Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.
6. "Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy." Testimony to Louisiana Public Service Commission, December 1996.

5. "Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.
4. "Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.
3. "Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.
2. "Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public Service Commission, May 1993.
1. "The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (Der), Hearings on Fuel Diversity and Environmental Protection, December 1992.

Selected Speaking Engagements

115. Rose, J.L., The Polar Vortex, System Reliability and Recent PJM Developments, American Municipal Power Conference, October 28, 2014.
114. Rose, J.L., Wholesale power Market Price Projection in California, Infocast, California Energy Summit, San Francisco, CA, May 28, 2014.
113. Rose, J.L., The Polar Vortex and Future Power system Trends, National Coal Council, 2014 Annual Spring Meeting, May 14, 2014.
112. Rose, J.L., The Polar Vortex and System Reliability, The Energy Authority (TEA), Jacksonville, FL, April 30, 2014.
111. Rose, J.L., Utility and Transco Plans and Transmission Projects to Deal with the Changing Generation Resource Mix, Panel Moderator, Transmission Summit Panel Discussion, March 14, 2014.
110. Rose, J.L., Examining Natural Gas and Power Price Dynamics During the Polar Vortex, APPA, March 10, 2014.
109. Rose, J.L., Polar Vortex – Skating too Close to the Edge, First Friday Club, March 7, 2014.
108. Rose, J.L., New Developments in the California Power Market, Infocast California Energy Summit, San Francisco, CA, December 3, 2013.
107. Rose, J.L., Financial Issues in Determining the Disposition of Fossil Power Plants, Managing the Power Plant Decommissioning, Decontamination, and Demolition Process, November 7, 2013.
106. Rose, J.L, Reality and Impacts of Plant Retirements, Reading Tea Leaves – The Future of America's Installed Power Plants, July 25, 2013.
105. Rose, J.L., Financial issues in Determining the Disposition of Fossil Power Plants, Plant Decommissioning, Decontamination, and Demolition, May 9, 2013.
104. Rose, J.L., Financial Issues in Determining the Disposition of Plant Decommissioning, Decontamination & Demolition Summit, Infocast, May 1, 2013.
103. Rose, J.L., Implications of Current Low Natural Gas Price Environment on Wholesale Power, Edison Electric Institute, May 3, 2012.

102. Rose, J.L., Anticipating the Next Turn in a Gas-Rich Environment, Key Pricing Drivers, and Outlook, Houlihan and Lokey Merchant Energy Conference, April, 24, 2012.
101. Rose, J.L., CREPC/SPSC Natural Gas - Electricity in West Panel, San Diego, April 3, 2012
100. Rose, J.L., EUCI Financing Transmission Expansion, San Diego, CA, March 8-9, 2011.
99. Rose, J.L., Vinson & Elkins Conference, Houston, TX, November 11, 2010.
98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA, June 29-30, 2010.
97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power Generation in the U.S., DOE-NETL, February 24, 2010.
96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.
95. Rose, J.L., CO_2 Control, "Cap & Trade", & Selected Energy Issues, Multi-Housing Laundry Association, October 26, 2009.
94. Rose, J.L., Financing for the Future - Can We Afford It?, 2009 Bonbright Conference, October 9, 2009.
93. Rose, J.L., EEI's Transmission and Market Design School, Washington, D.C., June 2009.
92. Rose, J.L., ICF's New York City Energy Forum - Market Recovery in Merchant Generation Assets, June 10, 2008.
91. Rose, J.L., Southeastern Electric Exchange - Integrated Resource Planning Task Force Meeting, Carbon Tax Outlook Discussion, February 21-22, 2008.
90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.
89. Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.
88. Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.
87. Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.
86. Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI - Securing the Nation's Energy Infrastructure, September 19, 2005
85. Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.
84. Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.
83. Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

82. Rose, J.L. "Assessing the Salability of Merchant Assets - What's on the Horizon?" Infocast - The Market for Power Assets, Phoenix, AZ, February 10, 2005.

81. Rose, J.L. "Market Based Approaches to Transmission - Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

80. Rose, J.L. "Supply & Demand Fundamentals - What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.

79. Rose, J.L. "Assessing the Salability of Merchant Assets - When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

78. Rose, J. L. "After the Blackout - Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

76. Rose, J.L., "Assessing the Salability of Merchant Assets - When Will We Hit Bottom?", Infocast's Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

75. Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York, NY, October 8, 2003.

74. Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

72. Rose, J.L., "Assessing the Salability of Merchant Assets - When Will We Hit Bottom?", Infocast's Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, "Spark Spread Outlook", July 17, 2003.

70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and Economy", June 24, 2003.

69. Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel Management Seminar, Frederick, MD, June 10, 2003.

68. Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for Recovery," March 31, 2003.

67. Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City, VA, March 25, 2003.

66. Rose, J.L., "Assessing the Salability of Merchant Assets - When Will We Hit Bottom?, Infocast's Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

65. Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY, February 24, 2003.

64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).
63. Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.
62. Rose, J.L., "Assessing U.S. Regional and the Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.
61. Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.
60. Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.
59. Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.
58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.
57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.
56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.
55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.
54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001
53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001
52. Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001
51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001
50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001
49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001
48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000.

46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management Conference, Washington, D.C., March 25, 1999.

30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development Conference, Chicago, Illinois, March 23, 1999.

29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting Conference, Atlanta, Georgia, February 25, 1999

28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.

19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

15. Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions," full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.

13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.

8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.

7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.

6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.

5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.

4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.

3. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.

2. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at
conference: Market Price Forecasting, Washington, D.C., October 23, 1997,

1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

Selected Publications and Presentations

Rose, J.L., "Return of the RTO: Auction Results Portend Recovery," White Paper, June 14, 2014.

Rose, J. L., "The Next Polar Vortex: How Long Will Grid Emergencies and Price Volatility Continue?" Public Utilities Fortnightly, June 2014.

Rose, J.L., "Wind Curtailment, Assessing and Mitigating Risks," White Paper, December 2012.

Rose, J.L. and Henning, B. "Partners in Reliability: Gas and Electricity," PowerNews, September 1, 2012.

Rose, J.L. and Surana, S. "Using Yield Curves and Energy Prices to Forecast Recessions – An Update." World Generation, March/April 2011, V.23 #2.

Rose, J.L. and Surana, S. "Oil Price Increases, Yield Curve Inversion may be Indicators of Economic Recession." Oil and Gas Financial Journal, Volume 7, Issue 6, June 2010

Rose, J.L. and Surana, S. "Forecasting Recessions and Investment Strategies." World-Generation, June/July 2010, V.22, #3.

Rose, J.L., "Should Environmental Restrictions be Eased to Allow for the Construction of More Power Plants? The Costco Connection, April 2001.

Rose, J.L., "Deregulation in the US Generation Sector: A Mid-Course Appraisal", Power Economics, October 2000.

Rose, J. L., "Price Spike Reality: Debunking the Myth of Failed Markets", *Public Utilities Fortnightly,* November 1, 2000.

Rose, J.L., "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes," *Public Utilities Fortnightly,* November 15, 1998.

Rose, J.L., "Why the June Price Spike Was Not a Fluke," *The Electricity Journal,* November 1998.

Rose, J.L., S. Muthiah, and J. Spencer, "Will Wall Street Rescue the Competitive Wholesale Power Market?" *Project Finance International*, May 1998.
Rose, J.L., "Last Summer's "Pure" Capacity Prices – A Harbinger of Things to Come," *Public Utilities Fortnightly*, December 1, 1997.
Rose, J.L., D. Kathan, and J. Spencer "Electricity Deregulation in the New England States," *Energy Buyer*, Volume 1, Issue 10, June-July 1997.
Rose, J.L., S. Muthiah, and M. Fusco, "Financial Engineering in the Power Sector," *The Electricity Journal*, Jan/Feb 1997.
Rose, J.L, S. Muthiah, and M. Fusco, "Is Competition Lacking in Generation? (And Why it Should Not Matter)," *Public Utilities Fortnightly*, January 1, 1997.
Mann, C. and J.L. Rose, "Price Risk Management: Electric Power vs. Natural Gas," *Public Utilities Fortnightly*, February 1996.
Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," *Public Utilities Fortnightly*, December 1995.
Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information," *Public Utilities Fortnightly*, May 1, 1995.
Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.

Employment History

ICF International	Managing Director	1999 - Present
ICF International	Vice President	1996-1999
ICF International	Project Manager	1993-1996
ICF International	Senior Associate	1986-1993
ICF International	Associate	1982-1986

ATTACHMENT II

[BEGIN CONFIDENTIAL] Attachment II

[redacted]

([redacted]

Delivery Period	AEP-Dayton	Kyger Creek		Clifty Creek	
	Hub Price	Nodal Price	Realized Nodal Energy Price	Nodal Price	Realized Nodal Energy Price
2017[1]	31.4	30.1	31.2	30.1	31.6
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1) [redacted]
2) [redacted]

[redacted]

Delivery Period	AEP-Dayton	Kyger Creek		Clifty Creek	
	Hub Price	Nodal Price	Realized Nodal Energy Price	Nodal Price	Realized Nodal Energy Price
[redacted][1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL]

ATTACHMENT III

[BEGIN CONFIDENTIAL] Attachment III

[redacted]

Delivery Period	Source	RTO Zone Price (Nom $/kW-yr)	RTO Zone Price (Nom $/MW-day)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]

[redacted]

1) [redacted]
2) Ref[redacted]

[END CONFIDENTIAL]

ATTACHMENT IV

[BEGIN CONFIDENTIAL] Attachment IV

[redacted]

Kyger Creek

Delivery Period	Energy Revenue	Capacity Revenue	Ancillary Revenue	Fuel Cost	Other Expenses	Gross Margin
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1) [redacted]
2) [redacted]

Clifty Creek

Delivery Period	Energy Revenue	Capacity Revenue	Ancillary Revenue	Fuel Cost	Other Expenses	Gross Margin
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1) [redacted]
2) [redacted]

[END CONFIDENTIAL]

ATTACHMENT V

[BEGIN CONFIDENTIAL] Attachment V

[redacted]

Delivery Period	Kyger Creek (%)	Clifty Creek (%)
[redacted]	[redacted]	[redacted]

1) [redacted]
2) [redacted]
[redacted]

[END CONFIDENTIAL]

ATTACHMENT VI

Attachment VI

[redacted]s [BEGIN CONFIDENTIAL]

Items	Units	Clifty Creek	Kyger Creek
Locational [1,2,3]			
Physical Location		Jefferson, IN	Gallia, OH
Nodal Bus Name/kV		06CLIFTY- 345 kV	06KYGER - 345 kV
Zonal Energy Market		PJM-AEP	PJM-AEP
Future Capacity Market		PJM RTO	PJM RTO
Technology [2]			
Online Year		1955/1956	1955
Configuration		6 subcritical boilers	5 subcritical boilers
Capacity [6]			
Summer Capacity	MW	[redacted]	[redacted]
Winter Capacity	MW	[redacted]	[redacted]
ICAP Capacity	MW	[redacted]	[redacted]
Full Load HR[2]	Btu/kWh	10,763	10,571
Primary Fuel [2]			
Primary Fuel		Bituminous Coal	Bituminous Coal
Fuel Source		NAPP/Illinois Basin	NAPP
Transportation Type		Barge	Barge
Availability			
Scheduled Maintenance[1]	%	11.0	10.0
Forced Outage Rate[6]	%	[redacted]	[redacted]
Availability	%	[redacted]	[redacted]
Operation & Maintenance [5]			
Non-Fuel Variable O&M	2016$/MWh	[redacted]	[redacted]
Emission Control Technology [2,4]			
NO_x		SCR (2003)	SCR (2003)
SO_x		FGD (Jet Bubbling Reactor) (2013)	FGD (Jet Bubbling Reactor) (2012)
Mercury		Yes	No
Emission Rates [1,2]			
CO_2	lbs/MMBtu	205	205
NO_x	lbs/MMBtu	0.13	0.10
SO_2	lbs/MMBtu	0.26	0.22

Source: [redacted]

[END CONFIDENTIAL]