DUKE ENERGY OHIO EXHIBIT _______

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	))	Case No. 17-34-EL-AAM
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
In the Matter of the Application of Duke Energy Ohio, Inc., 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. 17-1263-EL-SSO
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)))	Case No. 17-1264-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Defer Vegetation Management Costs.	))	Case No. 17-1265-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., to Establish Minimum Reliability Performance Standards Pursuant to Chapter 4901:1-10, Ohio Administrative Code.	)))	Case No. 16-1602-EL-ESS

REVISED

PUBLIC VERSION

SUPPLEMENTAL TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

DUKE ENERGY OHIO

July 10, 2018

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I. INTRODUCTION AND SUMMARY

Q. 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. HAVE YOU PREVIOUSLY TESTIFIED IN THIS MATTER?

A. Yes.

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 updated economic forecasts for Ohio Valley Electric Corporation's (OVEC's)[1] two coal-fired power plants, Clifty Creek and Kyger Creek, related to the request of Duke Energy Ohio to adjust Rider PSR as resolved through a settlement. Specifically, I provide updated forecasts based on two sets of assumptions, ICF's and ICF's with the Reference Case natural gas price forecasts of the US Department of Energy (DOE) Energy Information Agency's (EIA) 2018 Annual Energy Outlook (AEO).

Q. DESCRIBE THE OVEC AND DUKE ENERGY OHIO'S RELATIONSHIP TO OVEC.

A. Duke Energy Ohio has a 9 percent equity interest in OVEC. Additionally, Duke

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

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 107 MW from Clifty Creek and 88 MW of Kyger Creek for a total of 195 MW. Over the 2012 to 2017 period, average generation from the 195 MW was 0.98 million MWh.

Q. DOES YOUR DIRECT TESTIMONY PROVIDE ADDITIONAL DESCRIPTION OF OVEC?

A. Yes, my Direct Testimony describes the OVEC plants and their: (1) access to coal delivered via barge on the Ohio River, (2) extensive emission controls, (3) OVEC's diverse ownership, and (4) unique contract and history.

Q. HAS YOUR MODELING APPROACH CHANGED SINCE YOUR DIRECT TESTIMONY WAS PREPARED/FILED?

A. No. I use the same modeling approach described in my Direct Testimony. As discussed, I use the PROMOD and IPM production cost models.

Q. HAS YOUR FORECAST PERIOD CHANGED?

A. Yes. My forecast is for the period January 1, 2018 to May 31, 2025. Previously, my forecast was through mid-2040 when the ICPA expires. The January 1, 2018 to May 31, 2025 period covers the timing of the Stipulation and Recommendation filed in this proceeding on April 13, 2018. Furthermore, I sometimes report 2025 full year results to facilitate comparison with other full years.

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[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.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony contains the following sections:

- Summary;
- Updated Assumptions;
- Updated Market Forecasts;
- Updated Plant Forecasts;
- Uncertainty and hedge value; and
- Conclusions

Q. WHAT SPECIFIC FORECASTS ARE YOU PROVIDING?

A. I provide the following forecasts:

- **Wholesale market electricity prices** (firm, electrical energy and capacity);
- **OVEC plant utilization rates** (*i.e.*, capacity factors);
- **OVEC plant revenues** (primarily from sales of electrical energy and capacity into PJM's wholesale power markets; my Direct Testimony discusses these products in greater detail);
- **OVEC plant gross margins** (revenues less short run variable costs; variable costs are primarily the costs of the coal and secondarily variable non-fuel Operation and Maintenance (O&M) and emission allowance costs); and
- **OVEC plant net margins** (*i.e.*, gross margins minus demand charges). Demand charges have two components:
  - Fixed cash going forward costs such as fixed (as opposed to short run variable O&M) annual O&M, property taxes, General and Administrative (G&A); and

- o Recovery of and on already spent capital costs referred to as sunk costs.

I report two net margins. The first is net of cash going forward costs excluding sunk costs (*i.e.,* net of a portion of the demand charge). The second is net of total demand charges including sunk costs.

Lastly, my testimony briefly discusses the issue of annual price volatility, the relationship between my year-by-year price forecasts and annual price volatility, and hedge value of contracts like the ICPA that have less volatility than wholesale market prices.

Q. HOW IS YOUR SUMMARY ORGANIZED?

A. My summary has four main parts:

- **Approach and Updated Assumptions;**
- **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;
- **Annual Cost and Price Volatility and Hedge Value;** and
- **Conclusions**

I.1 APPROACH

Q. 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 the same amount of power from the market under ICF's Base Case conditions. I base my recommendations on the operations of Clifty Creek and Kyger Creek on the cash going-forward economics *i.e.,* excluding sunk costs. I also compare market purchases and the costs of OVEC power 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 consider a second scenario using the EIA natural gas price reference case forecast instead of ICF's updated natural gas price base case forecast. This is the only public forecast that uses a theoretically correct methodology. Gas prices are an important uncertainty. This is especially relevant because ICF forecasts that over the next 8 years, demand for natural gas will increase so much that we expect US production will increase from 74 Bcfd to 98 Bcfd – (*i.e.* by 32%). This demand will come from numerous sources including major increases in natural gas exports.

Third, I compare the annual volatility of the costs of the two procurement approaches (*i.e.,* ICPA contract and market) 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.

Q. SUMMARIZE YOUR ASSUMPTION UPDATES.

A. Key updates include:

- **Lower ICF Natural Gas Prices –** Over the 2018-2025 period, ICF gas price forecasts are lower on average by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] relative to those used in my Direct Testimony. All else equal, lower gas prices lower wholesale electricity prices, albeit at a significantly lower percentage rate than the percentage change in gas prices. Lower wholesale power prices in turn lower revenues and margins for OVEC. My gas price forecast is lower primarily because of updated gas supply forecasts that effectively decreased the long-term price elasticity of gas supply. As a result, even though updated natural gas demand is still forecast to grow significantly (*i.e.*, by approximately one-third over the next eight years), my updated gas price increases over time are less than they were in my previous forecast. The key supply side developments include: even greater improvements in drilling efficiency, well completion techniques, and fracturing technologies than previous forecast. Having noted ICF gas prices are lower, they still increase 39 percent in nominal terms between 2018 and 2025 due to significant demand growth, general inflation, and other factors.

- **Lower EIA Natural Gas Prices –** EIA also updated its forecasts of natural gas prices. Between 2018 and 2025, EIA's average gas price decreased by an amount similar to ICF's decrease: $0.65/MMBtu for EIA versus [BEGIN CONFIDENTIAL] [redacted] for ICF. However, EIA updated gas prices are significantly higher than ICF's. [END CONFIDENTIAL]
- **Lower OVEC Delivered Coal Prices** - Over the 2018-2025 period, updated delivered OVEC coal prices are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] This in part mitigates the impact of lower gas prices on OVEC's economics.

- **Lower OVEC Demand Charges –** OVEC demand charges are forecast to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] This in part mitigates the impact of lower gas prices on OVEC's economics.
- **Higher PJM Retirements –** Firm PJM power plant retirements in 2018 to 2021 increased by approximately 11 GW relative to my Direct Testimony, which include First Energy Solution's announced retirement of more than 4 GW of nuclear units made in late April, 2018. Firm new combined cycle unit additions 2018 to 2021 increased by approximately 2 GW. Greater retirements increased wholesale power prices, thus in part mitigating the impact of lower gas prices on OVEC's economics.
- **Other Assumptions Updates –** I updated several other parameters demand, capacity auction results, and other parameters.

I.2 MARKET PRICE FORECASTS

Q. WHAT ARE FIRM ALL-HOURS POWER PRICES?

A. Firm all-hours power prices have two components, all-hours electrical energy and capacity[4]. Firm power prices are the most comprehensive measure of wholesale prices, and I focus here on prices at PJM's AEP Dayton Hub.

[3] 2025 is a full year for comparison.

[4] 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.

Q. WHAT ARE YOUR FIRM ALL-HOURS POWER PRICE FOR THE AEP DAYTON HUB?

A. My updated forecast for the average firm all-hours 2018 to 2025 wholesale power price is [BEGIN CONFIDENTIAL] [redacted] my Direct Testimony where the average projected firm all-hours AEP Dayton hub price for the 2018-2025 period was [redacted] [END CONFIDENTIAL]

Q. WHAT IS THE 2016 TO 2025 TREND IN YOUR FIRM ALL-HOURS POWER PRICES?

A. The trend is positive, and has already started. Prices increased in 2017 and early 2018 from their low point in 2016, and this increase is forecast to continue on an expected value basis. In 2016, firm all-hours prices were $31.6/MWh. In 2017, power prices increased from $31.6/MWh to $33.2/MWh. In addition, in the most recent PJM capacity auction, RTO capacity prices increased by more than 80 percent. The 2018 – 2025 average firm all hours electricity price will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] My forecast is of the yearly (and sub-yearly) expected value (*i.e.*, probability weighted average) assuming average normal weather.

[5] 2025 is considered full year.

Q. WHY DO YOU COMPARE YOUR FORECAST TO 2016 PRICES?

A. 2016 was an unsustainable low point and evidence of high price volatility. This conclusion about 2016 levels is based on several considerations:

- **Extreme Conditions** - The winter of 2015/2016 was one of 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, Louisiana natural gas prices were the lowest since 1999. Gas prices at Dominion South, another gas price market location north of Pittsburgh, were the lowest ever.
- **Evidence of Non-sustainability –** Between 2014 and 2016, US drilling for oil and gas dropped 75 percent and there were over 100 bankruptcies in small and mid-size oil and gas producers.
- **Price Increases Between 2016 and 2017 and 2018 YTD –** Many spot and forward prices increased over the course of 2016, 2017 through early 2018. The increase in 2017 occurred in spite of 2017 being a warm winter compared to average.
- **Modeling** - Computer model simulations capturing the long-term dynamics of the power and related industries support higher average prices than 2016. This modeling also accounts for general inflation, long-term conditions including regulatory changes, rising demand for gas, etc.

Q. WHAT ARE ELECTRICAL ENERGY PRICES?

A. PJM purchases and OVEC sells electrical energy hourly and sub hourly and prices are expressed in $/MWh. Competitive prices equal the marginal costs of producing electrical energy by time-period and location. Electrical energy is the larger of the two components of firm wholesale electricity prices; specifically, I forecast that on average[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Q. WHAT IS YOUR FORECAST OF ELECTRICAL ENERGY PRICES?

A. I project that over the 2018 to 2025 period, all hours electrical energy prices will [BEGIN CONFIDENTIAL] [redacted]. I also project that they will increase from 2016 levels [redacted] My updated forecast for 2018 to 2025 nominal average electrical prices of [redacted] is [redacted] or [redacted] lower than by forecast in the Direct Testimony for 2018 to 2025. This primarily reflects impacts of lower gas prices and lower coal prices offset by other factors. [END CONFIDENTIAL]

Q. WHY DO YOU FORECAST INCREASING ELECTRICAL ENERGY PRICES OVER TIME?

A. 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, potential new regulations, new unit costs and general inflation (*i.e.*, average economy wide inflation measured using GDP deflator).

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] Thus, my updated forecast is [redacted] than my forecast in the Direct Testimony for 2018 to 2025. [END CONFIDENTIAL] This reflects several factors. First, there are changes in historical PJM auction results which I directly incorporate in my forecast. This includes the more than 80% increase in PJM RTO capacity prices the May 2018 auction relative to the May 2017 auction. Second, my post auction forecasts are modestly lower. This is because lower gas prices lead to higher dispatch for marginal capacity price setting units, and I assumed slightly lower physical heat rates for new combined cycles for delivery in 2024/2025.

Q. DOES YOUR CAPACITY PRICE FORECAST REFLECT ALREADY HELD CAPACITY AUCTIONS?

A. Yes, as noted. Specifically, PJM already purchased capacity through May 31, 2022, and my price forecast incorporates these results. Therefore, the majority of the forecast capacity prices reflect forward auction results.

[6] This includes full year pricing for 2025. Also we note that the January 1, 2018 to May 31, 2022 capacity prices in this analysis are set equal PJM capacity auction prices.

Q. DOES YOUR CAPACITY PRICE FORECAST INCREASE OVER TIME?

A. When disaggregated into periods of "already auctioned capacity" and "ICF projections" of capacity sales, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The key drivers of higher capacity prices between June 1, 2022 and 2025 compared to 2018 through May 31, 2022 include:

- The decrease in excess capacity due to retirements;
- Less depression of capacity prices levels by base capacity product; and,
- Likely additional reforms to the PJM capacity market such as correction of the current inappropriately low penalty rates for capacity performance,[7] efforts to curtail buy-side market power,[8] and resiliency initiatives[9]. These reforms provide qualitative support for my forecast of higher prices over time.

While prices increase, the increased price is lower than key PJM capacity price benchmarks. One benchmark for capacity prices is the net Cost of New Entry (CONE), and another is net CONE times the Balancing Ratio (typically 78 percent to 90 percent of CONE). Net CONE times the Balancing Ratio is the maximum safe harbor bid price and is designed to be the indifference point between providing energy only or entering into capacity agreement and then

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[7] See MIC Balancing Ratio, April 4, 2018, Monitoring Analytics, Joe Bowring, Siva Josyula. See also discussion of this issue in Direct Testimony.

[8] PJM, "*Capacity Market Repricing Proposal*", 2017; PJM, "*Proposed Enhancements to Energy Price Formation*", November 15, 2017.

[9] PJM, *Valuing Fuel Security"*,2018; PJM,*"Ott_Fuel Security Member Letter"*, April 30, 2018.

providing firm energy subject to penalties. I project the average PJM RTO capacity price will [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[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 my forecast of the expected (*i.e.*, probability weighted) value. I focus on one measure of annual volatility namely the range of annual all hours electrical energy prices for the AEP Dayton Hub. This measure is modestly higher relative to my Direct Testimony. Over the 2012-2017 six-year period, the range was $27.8/MWh to $44.1/MWh with a spread of $16.3/MWh. This spread is 49 percent 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 spread was $16/MWh or 44 percent of the average. The high volatility is driven in large part by variation in weather conditions (*e.g.*, weather was warm in the winters of 2012, 2016 and 2017 while the winters were cold in 2014 and 2015 and average[10] in 2013 and 2018), the lack of storage, natural gas price volatility,

[10] Compared to the 15 year national Heating Degree Day average.

variation in generation supply costs, industry cycles and changes in FERC regulations. Greater reliance on natural gas will increase spot power price volatility, especially in situations where natural gas production and delivery infrastructure falls behind increased natural gas consumption.

Q. HOW DOES THE MARKET VOLATILITY COMPARE TO THE VOLATILITY OF THE OVEC CONTRACT COST?

A. It is five times higher.

I.3 POWER PLANT FORECASTS

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

A. Between 2018 and 2025, I forecast the average[11] plant utilization rates will be [BEGIN CONFIDENTIAL] [redacted] The increase reflects increasing natural gas and electrical energy prices, the impact of retirements, growing electricity demand and the lack of new coal power plant construction. While higher than historical, my updated [redacted] for Kyger Creek and Clifty Creek respectively, than my forecast in the Direct Testimony for 2018 to 2025. [12] [END CONFIDENTIAL]

[11] Average plants utilization rates include 2025 as partial year.
[12] 2025 is a full year for comparison

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

A. Over the 2018 to 2025 period, in nominal dollars, I forecast the annual average total revenues for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. WHAT ARE YOUR FORECASTS OF CLIFTY CREEK AND KYGER CREEK GROSS MARGINS?

A. Gross margin equals revenues less fuel and other short run variable costs. Over the 2018 to 2025, in nominal dollars, I forecast gross margins will have a present value of [BEGIN CONFIDENTIAL] [redacted] [END

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[13] Duke Energy Ohio (DEO) owns 9% of the ICPA contract. In this annual average calculation, 2025 is considered as a full year.

[14] In average revenue rate calculation, 2025 is a full year. Revenues on average are higher than all-hours price because dispatch is high but not 100%.

[15] Partial year 2025.

[16] In gross margins average calculation, 2025 is a full year

CONFIDENTIAL] Revenues increase faster than costs and margins increase 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 power plant. Duke Energy Ohio provided ICF the forecast of OVEC's projected demand charges.[17] Between 2018 and 2025[18], total demand charges average approximately [BEGIN CONFIDENTIAL] [redacted] As noted, this forecast [redacted] in my Direct Testimony. [END CONFIDENTIAL]

Q. HOW SHOULD SUNK COSTS BE TREATED?

A. Society's economic value[19] 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 in the decision regarding the asset's utilization. My economic analysis excluding sunk costs concludes that OVEC should continue to operate its power plants. This is especially true when the hedge value of the contract and the improving price trend is considered.

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

[17] Demand Charges are from OVEC "20yearbillable.xls" spreadsheet
[18] 2025 is a full year in the average demand charge calculation.
[19] Assuming efficient pricing.

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 (*e.g.*, unanimous decision making). 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 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 power plants – *i.e.*, similar to other power plants 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 I defer to the expertise of the PUCO on how to treat the sunk costs with regard to rate recovery for the Company. I also acknowledge that this is a different, complex and unique situation. Finally, it is my understanding that most decisions and changes to the contract require unanimous consent. 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. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING EIA'S UPDATED GAS PRICES?

A. Also in Exhibit 1, I present the net present value of pre-tax net margins on a cash going-forward basis using the DOE Energy Information Agency (EIA) Annual Energy Outlook (AEO) 2018 Reference Case gas price forecast.[21] [BEGIN CONFIDENTIAL] [redacted]

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[20] [BEGIN CONFIDENTIAL [redacted] [END CONFIDENTIAL]

[21] US EIA's "*Annual Energy Outlook 2018*." This case assumes no national CO_2 regulations for all time periods.

[redacted] [END CONFIDENTIAL]

Q. DO THE NET MARGINS INCLUDE HEDGE VALUE?

A. No, the results shown do not include any hedge value even though the contracts costs are less volatile than relying on market. Adding hedge value would make the results more positive.

Q. HOW DOES THIS FORECAST COMPARE TO THE FORECAST IN THE DIRECT TESTIMONY?

A. In my Direct Testimony [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING TOTAL DEMAND CHARGES?

A. I present results with and without considerations of sunk costs (*i.e.*, with demand charges excluding sunk costs and including sunk costs) in Exhibits 1 and 2. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[22] Partial year 2025.

[BEGIN CONFIDENTIAL]

Exhibit 1
Duke Energy Ohio's Share of the OVEC Portfolio Net Margins
(Present Value millions $)

Case	Sunk Costs Included	2018-May 2025
ICF Base Case	No	0
AEO 2018 Reference Case	No	15

Source: ICF projections with supplementary data from AEO 2018, FERC Form 1, and OVEC

Note: Present value calculated for Jan 1, 2018 to May 31, 2025 using a discount rate of [redacted]

Exhibit 2
Duke Energy Ohio's Share of the OVEC Portfolio Net Margins
(Present Value millions $)

Case	Sunk Costs Included	2018-May 2025
Base Case	Yes	(77)
AEO 2018 Reference Case	Yes	(62)

Source: ICF projections with supplementary data from AEO 2018, FERC Form 1, and OVEC

Note: Present value calculated for Jan 1, 2018 to May 31, 2025 using a discount rate of [redacted]

[END CONFIDENTIAL]

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

A. Annual wholesale market price volatility is five times higher than volatility in the costs of Clifty Creek and Kyger Creek. I discussed above the volatility of market prices. [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

I.4 CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS?

A. The updated ICF Base Case value of net margins for OVEC between 2018 and 2025 is lower than in my Direct Testimony. This reflects lower gas and power prices with the impact mitigated in part by lower coal and non-fuel costs at the OVEC plants and retirements in the market including the effect of recent nuclear power plant retirements in and near Ohio.

My update to my 2018 to 2025 forecast concludes OVEC plants provide electricity on a going forward cost basis [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

My updated volatility estimates are nearly unchanged for both the market and the OVEC contract – *i.e.*, market is five times more volatile. Therefore, the lower volatility of OVEC contract is an advantage and the contract acts like a hedge. Adding any hedge value would make the plants positive or better than market on a cash going forward basis.

In the updated US EIA gas price case, net margins on a cash going forward basis are positive and very close to the ICF Base Case forecast in my Direct Testimony. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

This also supports and reinforces the conclusion that continued plant operation through 2025 is economic.

Accordingly, I conclude the plants should continue to operate.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

My current 2018-2025 forecasts do not include quantitatively three sets of regulatory developments that are favorable to the economics of Clifty Creek and Kyger Creek and that occurred since the filing of my Direct Testimony. 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 beyond 2025 compared to national CO_2 controls starting in 2022 as per the Clean Power Plan (CPP). While my Direct Testimony assumed no national CO_2 regulations until after 2025, prospects are now even more remote. Second, PJM has been developing capacity and energy market reforms that would increase prices. While these reforms do not quantitatively affect my forecast, they qualitatively support the upward trend in prices that commenced in 2017 and is continuing. Third, PJM, FERC and others may pursue grid resiliency initiatives economically favoring units like Clifty and Kyger Creek because they have significant amounts of on-site fuel. I have not quantitatively accounted for this possibility in my analysis.

II. RECENT WHOLESALE POWER PRICING TRENDS

Q. WHAT WERE THE WHOLESALE PRICES FOR ENERGY FOR THE LAST 9 YEARS?

A. Exhibit 3 below provides wholesale electrical energy market prices for the period from 2009 to 2017.[23] 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 2017, AEP Dayton Hub all-hours electrical energy prices averaged $33.8/MWh in real 2016 dollars, and $33.1/MWh in nominal dollars. Historically, Clifty Creek and Kyger Creek nodal prices averaged 5.5 percent lower compared to AEP Dayton Hub's all-hours prices. In nominal dollars, the range of AEP Dayton Hub's prices was from $44.1/MWh in 2014 to $27.8/MWh in 2016 or $16.2/MWh – *i.e.*, the lowest prices were in 2016. As noted, 2015/2016 winter weather was among the warmest on record and electrical energy prices and natural gas prices were very low.

[23] Historical energy pricing data come from publicly available sources including Platts, Ventyx, 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 3
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
	2017	28.6	27.7	29.2	28.2
	2018 YTD	35.1	32.6	36.6	34.0
	2012-2017	**33.8**	**31.9**	**33.1**	**31.2**
	2009-2017	**35.9**	**33.9**	**34.2**	**32.3**

Source: SNL Financial, Ventyx
Notes:
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.
2) 2018 YTD represents trades from Jan 1 – May 11, 2018

Q. WHAT WERE THE WHOLESALE PRICES FOR CAPACITY FOR THE LAST 9 YEARS?

A. As mentioned above, forward PJM capacity prices reflect PJM's auction for three-year forward capacity delivery for June 1 through May 31 of the following year. The auction is called the Base Residual Auction (BRA) and is held in May of each year. Thus, calendar year 2018 capacity prices reflect auction results in May 2014 for the period January 1, 2018 - May 31, 2018, and in May 2015 for June 1, 2018- December 31, 2018. Exhibit 4 shows calendarized 2013 to May 31, 2022 capacity prices from PJM auctions. Over the last 9 years, capacity prices in the RTO sub-region of PJM averaged approximately $36.5/kW-yr in nominal dollars (approximately $100/MW-day). As noted, most of the historic capacity prices do not reflect full implementation of the capacity performance arrangements. Even when PJM procured in the May 2017 auction 100 percent capacity performance product, it used 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 4
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	8.5
2018	53.3	18.6	14.7	13.0
2019	46.4	15.1	NA	NA
2020	31.5	NA	NA	NA
2021	41.4	NA	NA	NA
Jan 2022-May 2022	51.1	NA	NA	NA
2013-2021 Average	**36.5**	**14.4**	**15.8**	**15.6**
2018-2021 Average	**43.2**	**16.8**	**14.7**	**13.0**

Source: PJM

Q. WHAT WERE THE FIRM PRICES FOR THE LAST 9 YEARS?

A. Firm unit-contingent all-hour prices combine energy and capacity into a single $/MWh price by amortizing capacity payment over all the hours. Exhibit 5 below provides historical all-hours firm prices for the period from 2009 to 2017. Recent historical average of AEP-Dayton all-hours firm price is $36.5/MWh over the 2012 to 2017 time period.

Exhibit 5
Historical AEP-DAYTON All-Hours Firm Prices ($/MWh)

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

Source: PJM, Ventyx

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 power plants acting as operating reserves which can be quickly deployed by system operators, and give up the opportunity to participate in the energy market. Ancillary service revenues are a very small portion of total costs.

III. UPDATED MARKET MODELING ASSUMPTIONS

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

A. The key assumptions are coal prices, natural gas prices, firm new power plant builds and retirements, electricity demand growth, and demand side resources, market regulations, new thermal unit costs and performance and renewable assumptions.

Q. SUMMARIZE YOUR UPDATES.

A. ICF's updated natural gas prices and to a lesser degree coal prices are lower. All else equal, lower fuel prices lower electrical energy prices. However, the impact is significantly less than the change in gas prices on a percentage basis because coal sets prices in many hours and thus the decrease is less. Also, other changes support prices such as greater retirements – *e.g.,* recently announced nuclear power plant retirements. Lower prices adversely impact OVEC margins, but lower OVEC demand charges partly offset this impact; OVEC specific changes are discussed later. I also updated the EIA gas price forecast which is also lower than it was in the past though still higher than ICF's.

<u>III.1 UPDATED NATURAL GAS PRICES</u>

Q. HAS YOUR APPROACH TO MODELING NATURAL GAS PRICES CHANGED SINCE YOUR DIRECT TESTIMONY?

A. No. My forecasts in the first two years reflect NYMEX futures prices and from the fourth year on reflects ICF's Gas Market Model ("GMM"). GMM is a full supply/demand equilibrium model of the North American natural gas market.

The third year is an interpolation. I also present US EIA gas price forecasts. In addition, as discussed in my Direct Testimony, natural gas forecasts vary by sub-region, and season, are very volatile, especially relative to weather, and are discussed for expositional purposes based on Henry Hub market prices for delivery to a hub in Louisiana and Dominion South, a Marcellus and Utica gas hub located north of Pittsburgh. Natural gas price forecasts are also important drivers of short run variable electricity production costs and are frequently purchased monthly or daily.

Q. WHAT WERE YOUR GAS PRICE FORECASTS IN YOUR DIRECT TESTIMONY?

A. In my Direct Testimony, I forecast that the very low 2015-2016 gas prices at Henry Hub and Dominion South would recover and have an upward trajectory over time. I also forecast recovery in oil and gas drilling and continued growth in shale gas output in the Marcellus and Utica formations.

Q. WHAT HAPPENED?

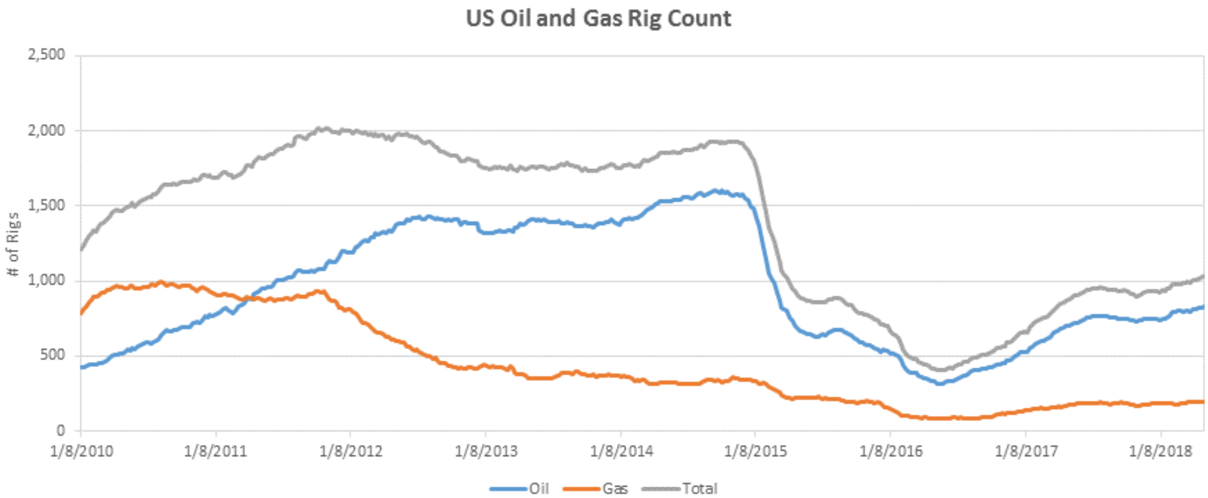
A. All of the above happened. Gas prices recovered 18 to 40 percent depending on location. In 2017, Henry Hub spot prices averaged $2.97/MMBtu, 18 percent above 2016 levels, and Dominion South averaged $2.11/MMBtu, 40 percent above 2016 levels of $1.50/MMBtu (see Exhibit 6). In the year to date 2018 period (through May 11, 2018), Henry Hub spot gas prices averaged $2.90/MMBtu and Dominion South prices averaged $2.5/MMBtu. The price increases reflect the lagged effects of lower drilling, increases in gas demand, and weather. Drilling has recovered along with prices (see Exhibit 7). Lastly, Marcellus and Utica gas output continued to grow even though the rest of the country's output decreased (see Exhibits 8 and 9).

Exhibit 6
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
2017	2.97	2.91	2.11	2.07	-0.86	-0.84
2018 YTD	2.90	2.78	2.50	2.40	-0.40	-0.39
Average 2005-2017	**4.81**	**5.33**	**4.68**	**5.22**	**-0.14**	**-0.11**
Average 2009-2017	**3.48**	**3.66**	**3.08**	**3.26**	**-0.40**	**-0.40**
Average 2012-2017	**3.16**	**3.23**	**2.45**	**2.51**	**-0.71**	**-0.71**

Source: SNL Financial, Bloomberg LP
2018 YTD represents trades from Jan 1, 2018 – May 11, 2018
Note: Dominion South is reported without LDC charges.

Exhibit 7
US Oil and Gas Rig Count



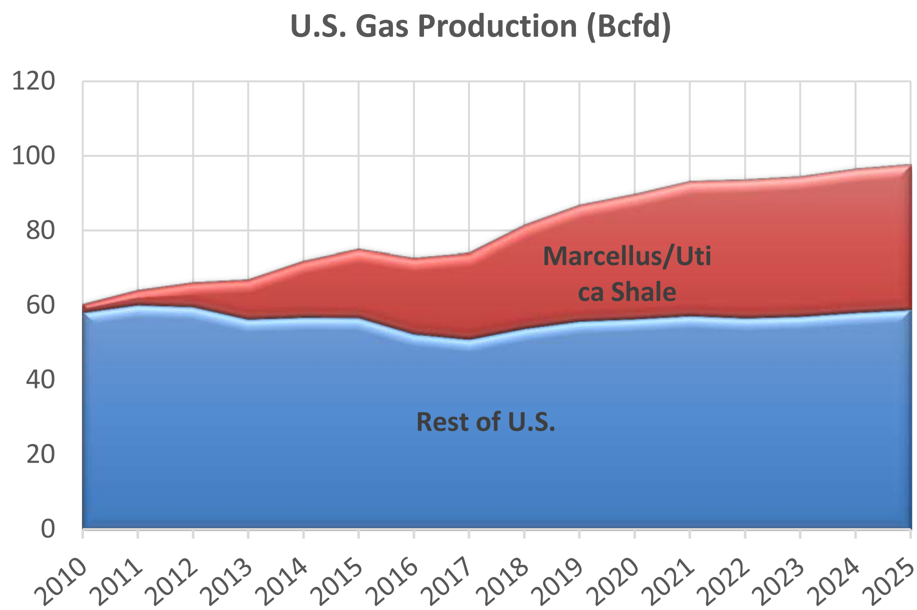
Source: Baker Hughes, from January 8, 2010 to May 4, 2018

Exhibit 8
Marcellus & Utica Gas Production (Bcfd)

Year	Rest of U.S.	Marcellus/Utica Shale
2010	58	2
2011	60	4
2012	60	7
2013	57	11
2014	57	15
2015	57	18
2016	53	20
2017	51	23
2018	54	28
2019	56	31
2020	57	33
2021	57	36
2022	57	37
2023	57	37
2024	58	38
2025	59	39

Source: Historical data (2010-2017) is obtained from PointLogic and projections (2018-2025) are ICF

Exhibit 9
Marcellus & Utica Gas Production (Bcfd)



Source: Historical data (2010-2017) is obtained from PointLogic and projections (2018-2025) are ICF

Q. WHAT ARE YOUR UPDATED GAS PRICE FORECASTS?

A. My updated gas price forecasts continue to show an upward trajectory but are at lower levels than in my Direct Testimony. Exhibit 10 presents ICF's natural gas price forecast in real and nominal dollar terms. [BEGIN CONFIDENTIAL] In 2018 and 2019, futures for natural gas prices are [redacted] in nominal dollars, respectively. By 2025, natural gas prices will [redacted] [END CONFIDENTIAL]

Q. WHY IS YOUR CURRENT GAS PRICE FORECAST LOWER?

A. My forecast of gas prices is lower because updated supply forecasts reduced the long-term price elasticity of gas supply – *i.e.*, effectively flattened the supply curve. Even though gas demand grows significantly (by nearly one-third in eight years), price increases are less than they were in my previous forecast. This reflects even greater improvements in drilling efficiency, well completion techniques, and fracturing technologies than previous forecast. Having noted ICF gas prices are lower, they still [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTAL] Exhibit 10
Comparison of Henry Hub Natural Gas Prices ($/MMBtu)

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

[redacted]

Notes:

[redacted]

[END CONFIDENTIAL]

Q. HOW DOES YOUR UPDATED NATURAL GAS PRICE FORECAST COMPARE TO UPDATED GAS FUTURES PRICES?

A. We show the NYMEX futures as a point of reference for those familiar with the NYMEX futures (see Exhibit 11). The ICF forecasts are higher and reflect ICF modeling including assumptions, model methodology, and other input data. While we use the futures for the first two years and use a weighted average of our forecast and futures in the third year, liquidity is not adequate to support long term usage of futures.

[BEGIN CONFIDENTIAL]

Exhibit 11

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

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

A. Exhibit 12 presents ICF's Dominion South gas price forecast in real and nominal dollar terms. In 2017, Dominion South gas prices were $2.11/MMBtu in nominal dollars. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Exhibit 12

[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]

Notes:

[redacted]

[END CONFIDENTIAL]

Q. WILL THERE CONTINUE TO BE YEAR-TO-YEAR VOLATILITY OF GAS PRICES?

A. Yes, 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 can be large imbalances between natural gas demand for and availability of natural gas delivery infrastructure. I emphasize my forecasts are of expected or probability weighted values and the yearly volatility around these forecasts are expected.

Q. WHAT OTHER NATURAL GAS PRICE FORECAST DID YOU ANALYZE?

A. I also analyzed the 2018 US EIA *Annual Energy Outlook (AEO)* forecast. The EIA AEO is the only public forecast using generally accepted methodology for the entire period.

Q. DID THE US EIA ALSO LOWER ITS REFERENCE CASE FORECAST OF NATRUAL GAS PRICES?

A. Yes, the 2018 EIA forecast of Henry Hub natural gas prices for 2018 to 2025 is lower on average by $0.65/MMBtu or -14 percent compared to the EIA 2017 forecast (see Exhibit 13)

Exhibit 13
Comparison of US EIA 2017 and 2018 AEO Gas Price Forecasts

Year	AEO 2018 Henry Hub (Nom$/MMBtu)	AEO 2018 Henry Hub (2016$/MMBtu)	AEO 2017 Henry Hub (Nom$/MMBtu)	AEO 2017 Henry Hub (2016$/MMBtu)	Difference – AEO 2018 minus AEO 2017 (Nom$/MMBtu)	Difference – AEO 2018 minus AEO 2017 (2016$/MMBtu)
2018	3.13	3.00	3.55	3.40	-0.42	-0.40
2019	3.55	3.34	4.22	3.96	-0.67	-0.62
2020	3.96	3.65	4.90	4.51	-0.94	-0.86
2021	4.02	3.62	4.88	4.40	-0.86	-0.77
2022	4.16	3.67	4.83	4.27	-0.67	-0.59
2023	4.42	3.82	4.97	4.30	-0.55	-0.47
2024	4.66	3.95	5.23	4.43	-0.57	-0.48
2025	4.93	4.09	5.45	4.52	-0.52	-0.43
Average 2018-2025	**4.11**	**3.64**	**4.75**	**4.22**	**-0.65**	**-0.58**

Source: US EIA, AEO 2017, 2018
Note: 2025 is a full year.

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

A. EIA's forecast of Henry Hub nominal gas prices is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

BEGIN CONFIDENTIAL] Exhibit 14

[redacted]

[redacted]	[redacted]	[redacted]	AEO 2018 Henry Hub (Nom $/MMBtu)	AEO 2018 Henry Hub (2016$/MMBtu)	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	3.13	3.00	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	3.55	3.34	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	3.96	3.65	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	4.02	3.62	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	4.16	3.67	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	4.42	3.82	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	4.66	3.95	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	4.93	4.09	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	**4.11**	**3.64**	[redacted]	[redacted]

[redacted] [END CONFIDENTIAL]

IV. UPDATED MODELING ASSUMPTIONS – COAL

Q. WHAT HAS BEEN HAPPENING TO SPOT HIGH SULFUR COAL PRICES?

A. Spot coal prices have been decreasing (See Exhibit 15). In 2016, spot prices for high sulfur coal from both Northern Appalachia and in the Illinois Basin for barge averaged $1.62/MMBtu, 19 percent below 2012 levels. In 2017, spot prices for high sulfur coal from both Northern Appalachia and in the Illinois Basin for barge averaged $1.53/MMBtu, 6 percent lower than 2016.

Exhibit 15
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
2017	36.3	1.45	35.6	1.42	35.5	1.61	34.8	1.58
2018 YTD	36.6	1.46	35.1	1.40	38.3	1.74	36.7	1.67
Avg (2012-2017)	**46.5**	**1.86**	**47.2**	**1.89**	**40.2**	**1.83**	**40.8**	**1.85**

Source: SNL Financial for 2012 to 2016 and Argus Coal Daily for 2017 and 2018. 2018 year to date is through May 11, 2018.

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

A. As shown in Exhibit 16, in 2016, delivered coal costs at Clifty and Kyger Creek were $2.23/MMBtu and $1.91/MMBtu, respectively. In 2017, the delivered coal costs at Clifty and Kyger Creek were lower on average: $2.24/MMBtu and

$1.84/MMBtu, respectively. The 2012 to 2017 averages were $2.54/MMBtu and $2/MMBtu, respectively.

Exhibit 16
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
2017	1.80	1.84	2.20	2.24
2018 Year to Date	1.76	1.83	1.98	2.07
Average (2012-2017)	**2.05**	**2.00**	**2.60**	**2.54**

Source: SNL Financial, EIA 923
Note: YTD represents data until February 2018

Q. WHAT IS YOUR FORECAST OF COMMODITY COAL PRICES?

A. Over time (see Exhibit 17), I forecast coal prices will remain relatively flat in real terms 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] Exhibit 17

[redacted]

	[redacted]				[redacted]			
	[redacted]		[redacted]		[redacted]		[redacted]	
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[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 18, delivered coal costs at Clifty and Kyger Creek are forecast to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

These projections are driven by data obtained from OVEC's own coal forecast projections.[24] Coal prices are lower than in my Direct Testimony.

[24] OVEC, "20yearbillable_ v1-1-2018".xlsx

[BEGIN CONFIDENTIAL] Exhibit 18

[redacted]

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

[redacted]

[END CONFIDENTIAL]

Q. HOW DOES YOUR DELIVERED COAL PRICE FORECAST COMPARE TO YOUR PREVIOUS FORECAST?

A. My current forecast is lower than in my Direct Testimony. Over the 2018 to 2025 period, updated OVEC-delivered coal prices are [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

BEGIN CONFIDENTIAL] Exhibit 19

[redacted]

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

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Exhibit 20

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

V. UPDATED MODELING ASSUMPTIONS – OTHER

Q. DID YOU UPDATE YOUR ASSUMPTIONS ABOUT PJM ELECTRICITY DEMAND AND DEMAND RESOURCES?

A. Yes.

Q. WHAT IS YOUR UPDATED FORECAST OF DEMAND FOR ELECTRICTY?

A. Projected peak and energy demand for PJM for the 2018 to 2025 time period are based on PJM's 2018 forecast. Regional forecasts for AEP Dayton demand are also from PJM's 2018 forecast. Exhibit 21 below provides an overview of the PJM RTO demand assumptions. PJM peak and energy demand are forecasted to grow at approximately 0.30 percent and 0.36 percent per year respectively in the near-term from 2018 to 2025. Over this same time period, AEP Dayton's growth is slightly higher at 0.4 percent. Growth rates are calculated before accounting for DSM levels.

Q. HOW DID THE UPDATED DEMAND FORECAST CHANGE?

A. Very little. By 2025, PJM demand is 370 MW or 0.2 percent higher for peak and 3.8 TWh or 0.5 percent lower for energy compared to the forecast in my Direct Testimony.

Exhibit 21
PJM RTO Zone Demand Forecast

Year	Energy Demand (GWh)		Peak Demand (MW)	
	Energy	Growth	Peak	Growth
2018	806,725	0.73%	152,107	0.52%
2019	809,000	0.28%	152,478	0.24%
2020	808,638	-0.04%	151,963	-0.34%
2021	808,882	0.03%	152,364	0.26%
2022	812,908	0.50%	152,885	0.34%
2023	816,817	0.48%	153,633	0.49%
2024	822,364	0.68%	154,244	0.40%
2025	824,140	0.22%	154,944	0.45%
Average 2018-2025	**813,684**	**0.36%**	**153,077**	**0.30%**

Source: PJM-ISO, "PJM 2018 Load Forecast", January 2018

Q. ARE YOUR UPDATED FORECASTS FOR DEMAND RESOURCES (DR) HIGHER THAN YOUR PREVIOUS FORECASTS?

A. Yes, by May 31, 2025, DR levels are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

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

A. Through May 31, 2021, DR levels are set at the levels in the PJM BRA capacity auction (see Exhibit 23). In PJM's May 2017 capacity auction for the capability period 2020/2021, demand resources totaled approximately 9.5 GW. Thereafter, demand resources were assumed to equal this amount. In PJM's most recent capacity auction held in May 2018 for the capability period 2021/2022, demand resources were higher at approximately 14 GW. The increase reflected the auction's higher cleared capacity prices. Because the implied capacity costs of marginal demand resources are close to the net costs of new gas combined cycles, an increase in demand resources would not have a significant impact on our forecast of capacity prices. Also, because nearly 80 percent of demand resources affect only super peak supply, the increase in DR resources would not have a significant impact on the forecast of the volume of OVEC sales.

Exhibit 22
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	20/21	21/22
ILR	2,107	2,110	2,108	2,110	1,594	NA	NA	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	7,820	11,126
EE Cleared	NA	NA	NA	NA	NA	569	679	822	923	1,117	1,339	1,247	1,515	1,710	2,832
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**	**9,531**	**13,958**
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	153,915	152,647
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%	6.2%	9.1%
% of Target Reserves	11%	13%	14%	14%	13%	34%	39%	59%	63%	52%	48%	49%	46%	37%	58%
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%	16.6%	15.8%

Source: PJM-ISO

[BEGIN CONFIDENTIAL]

Exhibit 23

[redacted]

[END CONFIDENTIAL]

Q. DID YOU UPDATE YOUR ASSUMPTIONS ABOUT FIRM PJM BUILDS AND RETIREMENTS?

A. Yes.

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”. Therefore, they are different than model projections of capacity additions – *i.e.*, non-firm or economic. We assume recent historical and firm new combined cycle builds for 2010 to 2021 in PJM will total approximately 28 GW (see Exhibit 24) of which 13.6 GW was built by 2017 and additional 14.4 GW is expected to come online by 2021. Over the 2010 to 2021 time period, firm retirements cumulatively are 40 GW including 5 GW of recently announced retirements by FirstEnergy (see Exhibit 24). In addition, as noted, ICF’s IPM model can decided to retire or add plants on a non-firm basis based on economics. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Exhibit 24
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	9,464	1,724
	2016	393	3,710
	2017	2,084	3,325
	2010-2017	**26,903**	**13,638**
	2018	5,377	7,167
	2019	2,631	4,501
	2020	2,062	2,109
	2021	3,058	620
	2018-2021	**13,128**	**14,397**
	2010-2021	**40,031**	**28,035**

Source: PJM-ISO; SNL Financial, Ventyx

Q. HAVE THERE BEEN SIGNIFICANT CHANGES IN FIRM ADDITIONS ANDS RETIREMENTS?

A. Yes. There has been a significant increase in firm retirements. Firm retirements in 2018 to 2021 increased by approximately 11 GW, which include First Energy Solution's retirement of approximately 5 GW of nuclear and coal units announced in late April, 2018. Firm new combined cycle unit additions 2018 to 2021 increased by approximately 2 GW.

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

A. Neither ICF nor EIA assume national CO_2 regulations during the 2018 to 2025 period. Between EIA AEO 2017 and 2018, EIA changed its views on CO_2 and assumes no national CO_2 in any period in its reference case.

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 summer 2021, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] 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). [BEGIN CONFIDENTIAL] [redacted]

[25] This reflects the underlying assumption of a generic GE HA.01 class combined cycle with a 6,500 Btu/kWh heat rate and improves over time. The price is expressed in $/summer kW.
[26] The 30 percent is the outcome of ICF studies of new natural gas-fired unit capital costs. This applies to heavy frame only as aero-derivatives are more expensive.

[redacted] [END CONFIDENTIAL] 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"). [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

However, ICF assumes that new units will have lower returns than the estimated merchant ROE 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).

ICF also assessed the impacts of the new corporate tax law. This new law lowered financing costs but this was partly offset by other changes in assumptions including higher property taxes.

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.

Q. HAVE THERE BEEN SIGNIFCANT UPDATES IN RPS OR RENEWABLES COSTS?

A. No, there have not been significant changes in the Renewable Portfolio Standards ("RPS") in place in each state in the 2018 to 2025 period, though New Jersey recently increased its RPS to 50 percent by 2030.[27] Generally speaking, wind and solar costs have been lowered in this update, but not enough to result in greater additions than required by RPS.

[27] This has not been included in our assessment, and would mostly affect power and REC prices in later years in eastern PJM – *i.e.*, post 2025.

VI. ELECTRICITY PRICE PROJECTIONS – ALL-HOURS ELECTRICAL ENERGY

Q. HAVE ELECTRICAL ENERGY PRICES RECOVERED FROM 2016 LEVELS?

A. Yes, AEP Dayton all-hours spot electricity prices in 2017 were 6.2 percent higher than 2016 prices (see Exhibit 25).

Exhibit 25
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
	2017	28.6	27.7	29.2	28.2
	2018 YTD	35.1	32.6	36.6	34.0
	2012-2017	**33.8**	**31.9**	**33.1**	**31.2**
	2009-2017	**35.9**	**33.9**	**34.2**	**32.3**

Source: SNL Financial, Ventyx
Notes:
[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
[2] 2018 YTD represents trades from Jan 1 – May 11, 2018

Q. HAVE YOU UPDATED YOUR MARKET PRICE PROJECTION FOR ELECTRICAL ENERGY?

A. Yes, for 2018 through 2025.

Q. WHAT ELECTRICAL ENERGY PRICES DID YOU FORECAST?

A. I forecast 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; and
- Realized Clifty Creek and Kyger Creek nodal prices, real and nominal dollars where realized refers to the prices in the hours in which the power plants dispatch.

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

A. I forecast that the 2018 to 2025 AEP Dayton all-hours price will average approximately [BEGIN CONFIDENTIAL] [redacted] which fully incorporates the effects of general economy-wide inflation (see Exhibit 26) [redacted] the AEP Dayton all-hours electrical energy price will average approximately [redacted] in 2016$ (see Exhibit 27). [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 26
ICF Forecast of AEP-Dayton Hub All-Hours Prices
and OVEC's All-Hours Nodal Energy Prices (Nom$/MWh) – 2018 to 2025

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

Source: ICF
Note: 2025 is a full year

Exhibit 27
ICF Forecast of AEP-Dayton Hub All-Hours Prices
and OVEC's All-Hours Nodal Energy Prices (2016 $/MWh) – 2018 to 2025

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

Source: ICF
Note: 2025 is a full year
[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 power plants are modestly [BEGIN CONFIDENTIAL] [redacted] the AEP Dayton hub prices. Between 2018 and 2025, I forecast that Clifty Creek and Kyger Creek all-hour nodal prices will be [redacted]

[redacted] the AEP Dayton all-hour price, respectively. [END CONFIDENTIAL] In comparison, over the 2012 to 2017 period, the all-hours nodal discount to the AEP Dayton hub price was 4.5 percent for Clifty Creek and 4.4 percent for Kyger Creek respectively.

Q. HOW DOES YOUR FORECAST OF ELECTRICAL ENERGY PRICES COMPARE TO YOUR DIRECT TESTIMONY?

A. My updated forecast for 2018 to 2025 nominal average electrical prices [BEGIN CONFIDENTIAL] of [redacted] is [redacted] or [redacted] lower than by forecast in the Direct Testimony for 2018 to 2025. This reflects impacts of lower gas prices and lower coal prices partly offset by retirements. [redacted] [END CONFIDENTIAL

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. Between the years 2018 to 2025, 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[28] and 2016 prices were 20 percent lower than the 2009 to 2016 average price of $34.9/MWh. 2016 included the warmest US winter on record, and 2016 annual Henry Hub gas prices were lower than any year since 1999.[29] 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. 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 power plants (*i.e.*, the difference between the costs of operating a gas plant and the market price), and if gas is on the margin,

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[28] SNL Financial’s recording of AEP Dayton Hub price stops at 2005.

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

the addition of more thermally efficient power plants can lower the implied heat rate. However, in this market location, coal is frequently on the margin setting electrical energy prices. Implied heat rates [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL]

Exhibit 28
[BEGIN CONFIDENTIAL] Historical and Forecast Market Implied Heat Rates (Btu/kWh)

	Source	AEP-Dayton Hub- All-hour Energy Price	Dominion South Gas Price	Market Implied Heat Rate- All-hour
Year	**Energy/Gas**	**(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	Historical/Historical	29.2	2.28	12,798
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average (2012-2017)		**33.1**	**2.62**	**13,512**
[redacted]		[redacted]	[redacted]	[redacted]

Source: SNL Financial, Bloomberg LP and Ventyx. ICF Forecast is from ICF
Note:
1) Dominion South is reported with LDC charges.
2) 2025 is a full year.
3) Hybrid forecast is an average of futures and ICF fundamentals

[END CONFIDENTIAL]

Q. HOW DOES YOUR 2018 TO 2025 ELECTRICAL ENERGY PRICE FORECAST COMPARE TO 2016 PRICES?

A. The 2018 to 2025 nominal average of [BEGIN CONFIDENTIAL] [redacted] higher than the 2016 price. The 2025 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 Bloomberg L.P. ("Bloomberg")[30] through December 31, 2021 for energy. In 2018[31], the forward price of $32.4/MWh is higher than the ICF forecast of [BEGIN CONFIDENTIAL] [redacted] due in large part to a non-weather normal January. By 2021, the forwards for all-hours AEP-Dayton Hub prices slightly decrease to $29.9/MWh and is 2 percent [redacted] (see Exhibit 29). [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 actual market transactions. Also, forwards are very volatile and follow spot prices. Thus, while we used forward gas and capacity prices we did not use forward power prices.

[30] Bloomberg L.P.
[31] Bloomberg L.P.

Exhibit 29
AEP-Dayton Hub Forward Electrical Energy Prices ($/MWh)

	Year	AEP-Dayton Hub All-Hours Energy Price (2016$/MWh)	AEP-Dayton Hub All-Hours Energy Price (Nom$/MWh)
Source	2018	31.1	32.4
	2019	27.8	29.5
	2020	27.1	29.4
	2021	26.9	29.9
	Average 2018-2021	**28.2**	**30.3**

Source: Bloomberg LP; forwards reflect an annual average over trade dates of 1/1/18 to 1/31/18
Note:
1) 2018 prices include historical values for January

VII. POWER PLANT DISPATCH AND REALIZED ELECTRICAL ENERGY PRICES

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

A. Historically, over the 2011 to 2017 period, Clifty Creek and Kyger Creek average utilization levels averaged 59 percent. Kyger Creek utilization was 61 percent and Clifty Creek utilization was 57 percent.

Exhibit 30
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	61%	50%
2017	73%	60%
Average (2011-2017)	**61%**	**57%**

Source: SNL Financial, Ventyx

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

A. Between 2018 and 2025, 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.

[BEGIN CONFIDENTIAL] Exhibit 31
Dispatch for the OVEC Plants – 2018 to 2025

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

Source: ICF projections
Note: 2025 is a partial year starting from January 1, 2025 to May 31, 2025
[END CONFIDENTIAL]

Q. HOW DOES YOUR FORECAST OF CAPACITY FACTORS COMPARE TO YOUR DIRECT TESTIMONY?

A. While my updated forecast is higher than historical levels, it is [BEGIN CONFIDENTIAL] [redacted] lower (in absolute terms) for Kyger Creek and Clifty Creek respectively than my forecast in the Direct Testimony for 2018 to 2025.[32] [END CONFIDENTIAL]

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[32] 2025 is a full year for comparison

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. Between 2018 to 2025, 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 32
ICF Forecast of All-Hours Hub, Nodal and Realized Nodal Energy Prices ($/MWh)

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

Source: ICF
Note: [redacted]

[END CONFIDENTIAL]

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

Q. HOW ARE ICF'S 2018-MAY 31 2021 CAPACITY PRICE FORECASTS FOR RTO DEVELOPED?

A. PJM capacity prices for January 1, 2018 to May 31, 2022 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 JUNE 1, 2022 TO MAY 31, 2025?

A. ICF projects PJM capacity prices 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 in the BRA capacity auction 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 33. I forecast that the average capacity price [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Regarding the already determined capacity prices, the RTO capacity price for delivery years 2018[33] to May 2022 averages $40.7/kW-yr in real 2016 dollars, and $43.9/kW-yr in nominal dollars.

Q. HOW DO YOUR UPDATED CAPACITY PRICE FORECASTS COMPARE TO THOSE IN YOUR DIRECT TESTIMONY?

A. As noted, I forecast that [BEGIN CONFIDENTIAL] [redacted] [redacted] Thus [redacted] my forecast in the Direct Testimony for 2018 to 2025. [END CONFIDENTIAL] This reflects several factors including the impacts of lower gas prices which lead to higher dispatch for marginal capacity price setting units, and also lower assumed physical heat rates for new combined cycles for delivery in 2025.

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[33] Calendarization of 2017/2018, 2018/2019, 2019/2020, 2020/2021.

[34] This includes full year pricing for 2025. Also we note that the January 1, 2022 to May 31, 2022 capacity prices in this analysis are set equal PJM capacity auction prices.

[BEGIN CONFIDENTIAL] Exhibit 33

PJM Capacity Prices – 2018 to 2025

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

[redacted]

Exhibit 34

[redacted]

Note: 2025 is a full year.

[END CONFIDENTIAL]

Q. WHY ARE CAPACITY PRICES INCREASING OVER TIME IN YOUR FORECAST?

A. Over time, primarily, as a result of retirements, there is a need for new units and their costs net of energy earnings set the capacity prices. In addition, capacity prices rise due to general inflation.

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

A. Yes. There are four reasons. First, as discussed in my Direct Testimony, 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 percent) 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. A recent Market Monitoring report discusses 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[35] showing the hour estimate is too high. Once this is fixed, prices will be more stable and move closer to net CONE.

Second, PJM is proposing that buy-side market power's impact on capacity prices be further mitigated via either minimum offer price rules for

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

existing units receiving non- market revenues or calculation of the capacity price excluding bids from resources receiving extra-market support.[36]

Third, PJM, FERC, and others are considering resiliency and could increase capacity compensation for coal power plants[37].

Fourth, while not capacity compensation, the price formation docket might increase energy prices above levels forecast, providing additional compensation.[38]

Q. DO THESE REGULATORY CHANGES QUANTITATIVELY AFFECT YOUR FORECAST?

A. No. However, they qualitatively support the potential for increasing capacity prices or greater total revenues over time contained in the forecast.

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 35, the average firm price between 2018 and 2025 is [BEGIN CONFIDENTIAL] [redacted]. In the near term, the average forecast all-hours firm price between 2018 and 2025 equals [redacted] than the recent historical average of $36.5/MWh over the 2012 to 2017 time period. [END CONFIDENTIAL]

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[36] "*Capacity Market Repricing Proposal*", PJM 2017.

[37] Scoping document draft, "Valuing Fuel Security", PJM, 2018. See also Letter from Andrew Ott to PJM Members, April 30, 2018.

[38] "*Proposed Enhancements to Energy Price Formation*", PJM, November 15, 2017.

Q. HOW DOES YOU FIRM PRICE ESTIMATE COMPARE TO THE FORECAST IN YOUR DIRECT TESTIMONY?

A. In comparison, in my Direct Testimony, the projected firm all-hours AEP Dayton hub price for the 2018-2025 period was [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 35
Forecast of AEP-DAYTON All-Hours Firm Prices ($/MWh)

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

Source: Ventyx, PJM-ISO, ICF
Note: 2025 is a full year.
[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 2012-2017 six-year period, the range was $27.8/MWh to $44.1/MWh or $16.3/MWh (see Exhibit 36). This range is 49 percent 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 44 percent of the average. This range is slightly higher in my updated forecast. 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.

Exhibit 36
All-Hours Electrical Energy Price Volatility ($/MWh)

Parameter	Supplemental Testimony	Direct Testimony
Average	33.1	33.9
Min	27.8	27.8
Max	44.1	44.1
Difference	16.3	16.3
Volatility (Difference Divided by Average)	49%	48%

Source: PJM
Note: Supplemental Testimony calculations from 2012 to 2017, Direct Testimony calculations from 2012 to 2016

Exhibit 37
AEP-Dayton Hub All-hours Firm Price ($/MWh)

Parameter	Supplemental Testimony	Direct Testimony
Average	36.5	37.1
Min	31.6	31.6
Max	47.6	47.6
Difference	16.0	16.0
Volatility (Difference Divided by Average)	44%	43%

Source: PJM
Note: Supplemental Testimony calculations from 2012 to 2017, Direct Testimony calculations from 2012 to 2016

IX. PROJECTIONS OF REVENUES AND GROSS MARGINS

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

A. Over the 2018 to 2025 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] The growth rate in revenues between 2018 and 2025 is [redacted]. [END CONFIDENTIAL]

[39] Duke Energy Ohio (DEO) owns 9% of the ICPA contract.

[BEGIN CONFIDENTIAL] Exhibit 38
Duke Energy Ohio's Share of OVEC Plants Gross Margins– 2018 to 2025
(Million nom$)

Kyger Creek

Delivery Period	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: ICF projections

1) Full year 2025 is shown to facilitate comparison with other years.
2) 2025 is a partial year starting from January 1, 2025 to May 31, 2025
3) Annual average calculated using full year 2025

Clifty Creek

Delivery Period	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: ICF projections
Notes:
1) Full year 2025 is shown to facilitate comparison with other years.
2) 2025 is a partial year starting from January 1, 2025 to May 31, 2025.
3) Annual average calculated using full year 2025

[END CONFIDENTIAL]

Q. HOW DOES YOUR FORECAST OF REVENUES COMPARE TO YOUR DIRECT TESTIMONY?

A. My updated forecast of total revenues on an annual average basis is [BEGIN CONFIDENTIAL] [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 2018 to 2025, 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]

Q. HOW DOES YOUR FORECAST OF GROSS MARGINS COMPARE TO YOUR DIRECT TESTIMONY?

A. Over the 2018 to 2025, in nominal dollars, I forecast gross margins will have a present value of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

X. PROJECTIONS OF DEMAND CHARGES AND NET MARGINS

Q. DID YOU UPDATE OVEC DEMAND CHARGES?

A. Yes. Demand charges are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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 power plants 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 2018 and 2025, 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.

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[40] Partial year 2025.

- **Recovery of Past Capital Cost/"Sunk" Costs** – Between 2018 and 2025, recovery of and on previously invested capital comprises [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]
- **Cash Going Forward Cost** - Between 2018 and 2025, 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[41] 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.

[41] Assuming efficient pricing.

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

A. Exhibit 39 shows our forecasts of net margins for ICF's case using dollars. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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[42] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 39
Base Case: Duke Energy Ohio's Share of OVEC Plants Net Margins– 2018 to 2025
(Million nom$)

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]

Source: ICF projections are used for Gross Margins and Net Margins. Demand Charges are from OVEC "20yearbillable.xls" spreadsheet.
Notes:
1) Full year 2025 is shown to facilitate comparison with other years.
[redacted]
[END CONFIDENTIAL]

In Exhibits 40 and 41, we have shown the net present value of pre-tax net margins across the ICF Base Case and the DOE Energy Information Agency (EIA) Annual Energy Outlook (AEO) 2018 Reference Case gas price forecast case.[43] Results are shown with and without considerations of sunk costs. EIA's forecast of natural gas prices are higher than ICF's, and hence, if used increases savings approximately back to the same level as in my Direct Testimony. The results shown do not include any hedge value even though the contracts costs are

[43] US EIA's "*Annual Energy Outlook 2018*." This case assumes no national CO_2 regulations for all time periods.

less volatile than relying on market. Adding hedge value would make the results more positive.

[BEGIN CONFIDENTIAL] **Exhibit 40**

[redacted]

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

Exhibit 41

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	(77)
[redacted]	[redacted]	(62)

[redacted]

[END CONFIDENTIAL]

If natural gas prices were [BEGIN CONFIDENTIAL] [redacted] the updated US EIA Base Case[44] gas prices, [redacted] [END CONFIDENTIAL]

[44] US EIA's "*Annual Energy Outlook 2018*"

Q. HOW DOES THIS FORECAST COMPARE TO THE FORECAST IN THE DIRECT TESTIMONY?

A. In my Direct Testimony, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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[45] 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 decreases [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] [redacted] If gas prices were [redacted] [END CONFIDENTIAL]

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

Q. WHAT IS YOUR ASSESSMENT 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 2017 was $2/MMBtu to $2.5/MMBtu or $0.5/MMBtu. This was [redacted] of the average. Total costs ranged from [redacted]. This [redacted] of the average. This compares favorably to the [redacted] for the firm power price – *i.e.*, the volatility of the market is approximately [redacted] [END CONFIDENTIAL]

XI. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS?

A. My update for the 2018 to 2025 period concludes OVEC plants provide electricity on a going forward cost basis [BEGIN CONFIDENTIAL] [redacted] This conclusion becomes stronger and reinforced under the updated US EIA gas price forecast case. [redacted] using the ICF Base case. Accordingly, [redacted] [END CONFIDENTIAL]

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

I have not conducted a detailed review of the OVEC contract, and its complex regulatory history, and defer to the PUCO's expertise on how sunk costs be treated with regard to rate recovery for Duke Energy Ohio. 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.

The OVEC plants also benefit from three important regulatory trends gaining strength since my Direct Testimony. First, environmental regulatory pressure on the plants is lower. Second, PJM is pursuing several initiatives that would increase compensation for power plants including additional protections against buy-side market power in the capacity markets and less suppression of electrical energy prices. Third, PJM, FERC, and others are considering resilience initiatives that would economically favor the OVEC plants because of their on-site fuel. I have not quantitatively included these trends though they qualitatively support the conclusion that the plants should continue to operate through 2025.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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

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.

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.

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

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

133. Expert Declaration, in support of (1) The motion for preliminary and permanent injunction against FERC (2) The motion for entry of an order authorizing to reject certain energy contracts (3) The motion for entry of an order authorizing to reject a certain multi-party intercompany power purchase agreement with the Ohio Valley Electric Corporation. On behalf of FES, March 31, 2018.
132. Direct Testimony, Case No. 17-872-EL-RDR, On behalf of Duke Energy Ohio, March 31, 2017131. 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

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Attachment VI OVEC Plant Parameters [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]
UCAP 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: 1) ICF, 2) SNL Financial, 3) PJM-ISO, 4)www.OVEC.com, 5) OVEC “20yearbillable.xls” spreadsheet, 6)Duke Energy Ohio

[END CONFIDENTIAL]