Company Exhibit _____

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)	Case No. 14-1297-EL-SSO

DIRECT TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

AUGUST 4, 2014

PUBLIC VERSION

Company Exhibit _____

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I. INTRODUCTION

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

A. My name is Judah L. Rose. I am a Managing Director of ICF International ("ICF"). My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

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

A. After receiving a degree in economics from the Massachusetts Institute of Technology and a Master's Degree in Public Policy from the John F. Kennedy School of Government at Harvard University. I have worked at ICF for over 32 years. I am a Managing Director and co-chair of ICF's Energy Advisory and Solutions practice. I have also served as a member of the Board of Directors of ICF International and am one of three people among ICF's roster of 5,000 professionals to have received ICF's honorary title of Distinguished Consultant.

Q. WHAT IS ICF INTERNATIONAL?

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

Q. WHO ARE ICF'S CLIENTS?

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

In the private sector, for over 40 years, ICF has provided forecasts and other consulting services to major United States and Canadian electric utilities. In the U.S., ICF has worked with utilities such as AES, American Electric Power, Allegheny, Arizona Power Service, Dominion Power, Delmarva Power & Light, Dominion, Duke Energy, FirstEnergy, Entergy, Exelon, Florida Power & Light, Long Island Power Authority, National Grid, Northeast Utilities, Southern California Edison, Sempra, PacifiCorp, Pacific Gas and Electric, Public Service Electric and Gas, PEPCo, Public Service of New Mexico, Nevada Power and Tucson Electric. ICF also works with Regional Transmission Organizations ("RTOs") and similar organizations, including the Mid-Continent Independent Transmission System Operator ("Midwest ISO"), the Electric Reliability Council of Texas, the Western Electric Coordinating Council, WestConnect, and the Florida Regional Coordinating Council.

Q. WHAT TYPE OF WORK DO YOU TYPICALLY PERFORM?

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

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company (the "Companies").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses my projections for wholesale market electricity prices over the next 20 years and discusses the issue of price volatility.

Q. PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS

A. I cover three main areas in my testimony:

<u>Recent Developments</u>

The two key wholesale markets for electricity are the electrical energy and capacity markets. Both have been affected by unanticipated developments which have lowered prices over the past few years. These include:

- The Great Recession, which contributed to lower demand, excess capacity, and thus lower prices.
- The development of substantial natural gas supplies from shale formations using horizontal drilling and "fracking" technology, especially in the northeastern sub-regions of PJM, which depressed natural gas electrical energy prices.
- The development of Demand Resources ("DR") in PJM, which depressed capacity prices, especially in the period when power plants retirements would otherwise have greatly increased price.
- Recent warm winters prior to the 2013/2014 winter.
- Changes in environmental regulations which lowered SO_2 and NO_x allowance prices, which in turn lowered electrical energy prices.

However, in my testimony I explain that these trends are not expected to continue, and why therefore a projection of future prices based on recent conditions would be flawed.

Price Forecast

Due to several emerging factors in energy markets and regulation, I anticipate that market prices for electrical energy and capacity will increase on both a nominal and a real basis over the 20 years starting January 1, 2015 and ending December 31, 2034.

Regarding electrical energy, in real 2013 dollars (i.e., adjusted for general inflation), the all-hours AEP Dayton price average for 2009 to 2013 was approximately $34/MWh. I anticipate that the same price index will average approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] (see Attachment II). Over the same period in nominal dollars, which fully incorporates the effects of general economy-wide inflation, the AEP Dayton all-hours electrical energy price will average approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] the 2009 to 2013 average. The prices for the ATSI Zone regional average exhibit [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The main reasons for these higher electrical energy prices include:

- Higher forecast natural gas prices;
- Greater reliance on natural gas as the price setting fuel in the electrical energy markets, and less reliance on coal; the variable costs of natural gas generation are higher than natural gas;
- Greater reliance on more costly units as demand grows and units retire;

- Greater reliance on natural gas plants occurs because of electricity demand growth, and coal power plant retirements. Retirements reflect tightened environmental regulations and other factors. All new thermal units will be natural gas-fired;
- CO_2 emission regulations leading to CO_2 emission allowance prices in $/ton which raise electrical energy prices in the forecast starting in 2020.

Regarding capacity prices, the RTO capacity price for delivery years 2013 to 2017 averages $30/kW-yr in real 2013 dollars. I anticipate that the RTO price will average [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

I anticipate that the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for several reasons:

- Elimination of excess capacity due to coal and other power plant retirements, and to a lesser extent, to electricity demand growth. The power plant retirements are primarily of older, smaller, coal power plants that are less controlled for air emissions.
- Less capacity price depression from DR; prices have been lowered by past FERC policies that provide preferences to DR, but this depression is unsustainable, has recently been decreased, and is likely to be less than in the past. In fact, the end of DR in FERC markets could be imminent due to a key recent federal court

decision which eliminates DR from directly participating in FERC jurisdictional electrical energy markets.[1]

- Less capacity price depression from capacity imports from other regions.
- Less capacity price depression from historically low financing costs, and low capital costs for new units. Low costs in these drivers of capacity prices reflect poor economic conditions, and hence, are expected to be temporary and likely to reverse as the economy recovers. Put another way, both capital and financing costs are expected to increase as demand for new capacity increases and as financing costs regress to historic conditions. This will in turn raise capacity prices.
- Less capacity price depression by the availability of pockets of low cost natural gas within the PJM footprint, which creates greater energy margins for new natural gas plants and lowers net capacity costs[2] and capacity prices. Infrastructure investment in the natural gas industry is expected to increase natural gas prices in the supply pockets, decreasing new power plant margins from selling electrical energy and thus increasing net capacity costs.

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[1] United States Court of Appeals for the District of Columbia Circuit, Decided May 23, 2014, No. 11-1486, Electric Power Supply Association, Petitioner vs. FERC. Similar reasoning may apply to DR in capacity markets and formal complaints asserting as such have been filed at FERC.

[2] Net capacity costs equal total going forward fixed costs less energy margin. Net capacity costs together with demand for capacity drive capacity prices.

Power Price Volatility

Power prices have exhibited very significant volatility across both short and long time scales: hourly, daily, seasonally, and annually. I anticipate this significant volatility to continue. This projection reflects several factors, including:

- The lack of storage for power;
- Volatile fuel markets, especially natural gas markets and, in particular, gas markets in delivery areas exhibiting increasing reliance on natural gas generation;
- Variations in generation variable costs that lead to high prices when more costly units are the incremental, or marginal, price setting source of power;
- Economy-wide and power generation industry cycles; and
- Changing FERC policies and regulations.

All else being equal, consumers and producers prefer less price volatility because price volatility complicates budgeting and planning. Volatility also increases the costs of financial hedging due to the increase in collateral requirements, which are often mark-to-market, and hence, fluctuate with price. For many end-users, the growing correlation between natural gas and power price increases the impact of high natural gas prices, since they imply that higher power bills will follow. This increases the preference for lower volatility and a more stable and predictable set of costs. Lastly, the decreasing amount of non-natural gas-fueled thermal generation capacity increases the difficulty of physical hedging.

II. DESCRIPTION OF THE WHOLESALE ELECTRICITY MARKET

Q. WHAT ARE THE BASIC COMPONENTS OF THE WHOLESALE ELECTRICITY MARKET?

A. At its most general level, the wholesale electrical energy market has three main generation service components: (1) energy, (2) capacity, and (3) ancillary services. Generators incur costs to meet requirements in each of these areas, and are compensated for those costs in a variety of ways. The principal generation costs are typically for electrical energy production and capacity, with the costs of ancillary generation services being much smaller.

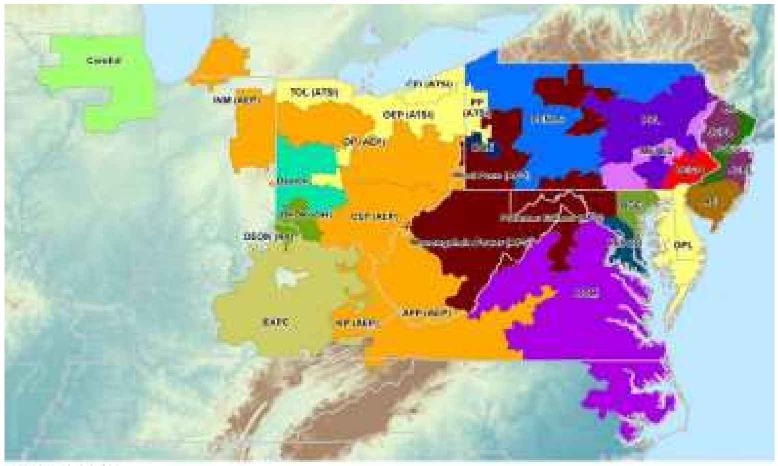
Q. WHAT ARE CAPACITY MARKETS?

A. In a deregulated market, where energy market bids are constrained to short-run variable costs, existing units may not be able to cover their fixed costs (e.g., property taxes, annual labor, SG&A, OEM upgrade fees), rendering them uneconomic in the long term. Further, new units may not earn sufficient recovery on and of capital. In theory, the capacity market enables generators to recover their fixed costs and maintain an adequate level of reserves. It therefore provides supplemental revenue to cover the going-forward costs of marginal sources. As power plant earnings in the energy markets increase, capacity prices generally tend to decrease, and vice versa.

Q. HOW ARE GENERATORS COMPENSATED FOR CAPACITY COSTS?

A. In Ohio, generators are compensated for capacity costs by participating in the PJM Reliability Pricing Model ("RPM") process, which includes self-supply, bilateral contracts, and the Base Residual Auction ("BRA") process. A map of PJM's RPM Local Delivery Areas ("LDAs") is shown in Figure 1. Though not shown, the RTO delivery area covers those LDAs which do not break out at separate clearing prices in the BRA auction process. PJM is the largest RTO in terms of demand served and has the nation's largest capacity market.

Figure 1
PJM RPM LDAs



Source: PJM ISO

Some generators in PJM also sell their capacity through non-PJM bilateral contracts based on either costs, market prices, or some combination of the two (such as AEP Ohio's contract with AEP Generation after corporate separation). Finally, in addition to PJM-related revenues, AEP Generation (through AEP Ohio) is compensated for capacity costs through a cost-based reimbursement structure combined with a nonbypassable retail charge.

Q. HOW ARE GENERATORS COMPENSATED FOR ENERGY COSTS?

A. Nearly all generators in the PJM footprint participate in the PJM energy markets, i.e., the PJM Day-Ahead or Hourly energy markets on a hedged or unhedged basis. Most hedges are short-term or medium-term. Generators also sell energy directly to customers, sell energy to Load Serving Entities ("LSEs"), and bid into wholesale auctions.

Q. HOW ARE GENERATORS COMPENSATED FOR ANCILLARY SERVICES COSTS?

A. Generators are compensated for ancillary services through either cost-based rates, the PJM market, or through market-based sales. As noted, ancillary service revenues are a very small portion of total costs.

III. RECENT WHOLESALE POWER PRICING TRENDS

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

A. Table 1 below provides wholesale electrical energy market prices for the period from 2009 to 2013.[3] Electrical energy prices are set node-by-node, but PJM reports load weighted zonal averages for demand nodes and hub simple averages for supply nodes. The ATSI Zone was not part of the PJM market until June 2011, and hence, the ATSI zonal prices are not available prior to June 2011. Between 2011 and 2013, AEP Dayton Hub all-hours electrical energy prices averaged $34.4/MWh in real 2013 dollars, and ATSI Zone all-hours prices averaged $35.4/MWh. Thus, ATSI zonal prices are modestly above AEP Dayton Hub prices. Between 2009 and 2013, AEP Dayton Hub averaged $34/MWh in 2013 dollars, and $35.1/MWh in nominal dollars. As a result, there is little difference between an average 2009 to 2013 and 2011 to 2013 prices.

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

Table 1
Historical Electrical Energy Prices ($/MWh)

Period	Source	Year	AEP-Dayton Hub	ATSI Zone	AEP-Dayton Hub	ATSI Zone
			All-Hours Energy Price (2013$/MWh)	All-Hours Energy Price (2013$/MWh	All-Hours Energy Price (nom$/MWh)	All-Hours Energy Price (nom$/MWh
Period	Historical	2009	30.9	NA	33.0	NA
		2010	35.7	NA	37.6	NA
		2011	37.5	38.1	38.7	39.3
		2012	30.8	31.6	31.2	32.1
		2013	35.0	36.5	35.0	36.5
		2011-2013	**34.4**	**35.4**	**35.0**	**36.0**
		2009-2013	**34.0**	**NA**	**35.1**	**NA**

Source: SNL Financial; Year 2011: ATSI covers June 1, 2011 to December 31, 2011
NA=Not Available

PJM capacity prices are established via a three-year forward auction. Thus, 2017 capacity prices reflect auction results in May 2013. In Table 2, showing the 2013 to 2017 delivery year, capacity prices in the RTO sub-region of PJM average approximately $30/kW-yr in 2013 dollars. In the ATSI Zone sub-region, capacity prices average approximately $57/kW-yr[4] over 2016 and 2017.

[4] Prices are often expressed in PJM markets in $/MW-day. To convert to $/MW-day, $/kW-yr prices are divided by 0.365. Thus, for example, ATSI Zone prices of $58/kW-yr average $159/MW-day when converted to $/MW-day. Another convention is to report capacity prices in $/kW-month, which is one-twelfth of the $/kW-yr price. We frequently use $/kW-yr because our 20-year forecast is presented annually.

Table 2
BRA Capacity Prices ($/kW-yr)

Source	Delivery Period[1]	RTO Zone Capacity Price (2013$/kW-yr)	ATSI Zone Capacity Price (2013$/kW-yr)	RTO Zone Capacity Price (nom$/kW-yr)	ATSI Zone Capacity Price (nom$/kW-yr)
Historical	2013	8.4	NA	8.4	NA
	2014	30.6	NA	31.2	NA
	2015	46.5	NA	48.5	NA
	2016	31.7	74.9	33.7	79.7
	2017	32.1	39.9	34.9	43.3
	2013-2017 Average	**29.9**	**57.4**	**31.3**	**61.5**

Source: PJM-ISO
[1] Calendar year. Capacity delivery year is June 1 to May 31.

Q. WHAT IS NOTEWORTHY ABOUT THE WHOLESALE MARKET PRICE RESULTS THROUGH THIS HISTORICAL PERIOD?

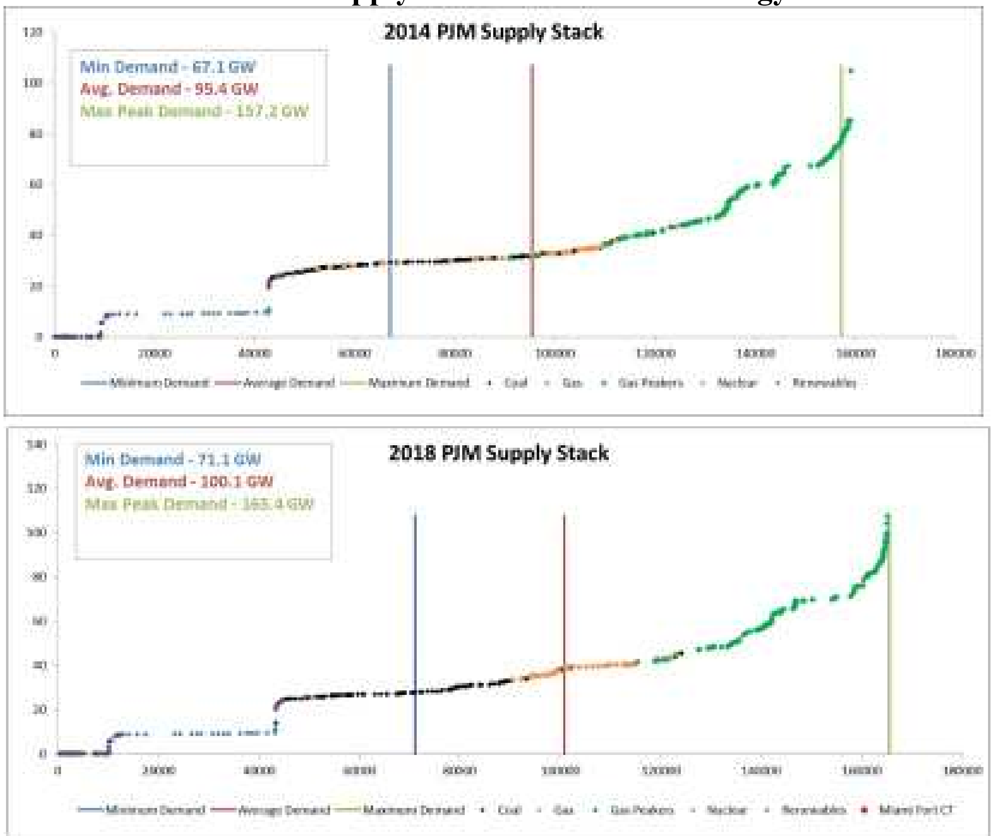
A. Over the last few years, there were several developments which decreased wholesale power prices relative to some prior periods and relative to expectations. These developments included:

- **<u>Electricity Demand</u>** – In late 2007 and through mid-2009, the U.S. economy entered what has become widely known as the "Great Recession," during which the economy contracted significantly. As a result, the demand for electricity dropped significantly, thereby contributing to a decrease in wholesale power prices. While a simplification, this can be thought of as an unexpected shift in the power "demand curve" to the left. In the capacity market, this shift towards less demand resulted in excess capacity and lower capacity prices. Similarly, in the energy markets, demand shifting to the left along the electrical energy supply curve resulted in lower electrical energy prices (see Figure 2).[5]

- **Demand Resources** – Another key factor that depressed PJM capacity prices was the unexpected growth in DR. Nearly all the DR that has cleared the PJM capacity market has been the category of interruptible load that is only required to operate in the summer months for up to 60 hours per year. Past FERC policy providing preferences to DR over generation has caused DR to play a key role in depressing capacity prices.

[5] Note: actual modeling of the power markets is much more detailed, as is discussed later. Rather, this description is presented for broad illustrative purposes.

Figure 2
Illustrative PJM Supply Curves – Electrical Energy Markets



Source: ICF International

- **<u>Natural Gas Prices</u>** – Another key factor that unexpectedly lowered wholesale market prices over the past few years was the decrease in natural gas prices. In the 2009 to 2013 period, natural gas prices decreased largely due to growth in shale gas supply but also due to warm winter weather, especially in the winter of 2011/2012 which was the warmest U.S. winter in the 1931/1932 to 2011/2012 period. The decrease in natural gas prices can be considered as causing a decrease in the level of the electrical energy supply curve sections composed of natural gas-fired power plants thereby decreasing electrical energy prices. Secondarily, the surprising development of large natural gas resources in PJM, especially Marcellus natural gas in western PJM, also contributed to decreasing capacity prices. This is because owners of new natural gas-fueled power plants near the center of this natural gas production believe that they can earn more electrical energy revenues via access to very low natural gas prices than expected prior to the shale gas development. Prices are especially low in these areas because they are currently inadequately served by natural gas infrastructures. As power plant electrical energy net revenues increase, net capacity costs (i.e., going forward fixed costs less energy earnings) decrease, thereby lowering capacity prices.

- **<u>New Power Plant Capital Costs and Financing Costs</u>** – Lower capital and lower financing costs unexpectedly lowered the costs of building new natural gas fueled power plants, which correspondingly lowered the cost of new capacity. All else equal, this lowered capacity prices.
- **<u>Power Imports</u>** – PJM's tariff allowed planned imports to offer into the capacity market without being physically deliverable. Failure to require planned imports to offer without physical deliverability allowed for a large amount of imports to bid into and clear the capacity market. The large quantity of potentially undeliverable capacity further suppressed capacity prices.
- **<u>Environmental Regulations</u>** – Over compliance on certain environmental regulations caused SO_2 and NO_x allowance prices to fall close to zero. This lowered the variable costs of producing electrical energy. This over compliance was the result of compliance with new separate tighter regulations.

Q. WHAT DO THESE DRIVING FACTORS AND TRENDS TELL YOU ABOUT THE PREDICTIVE POWER OF HISTORIC ELECTRICITY PRICES?

A. As is discussed later in greater detail, it is likely that the recent trends that served to soften prices will end or reverse, so it is unlikely that future electricity prices will mirror the relatively lower prices of the last few years. Future electricity prices will likely instead be driven upwards by a series of trends, including:

- **<u>Environmental Regulations</u>** – For years, coal plants have served a valuable role in providing stable and affordable base load generation capacity throughout the Midwest, including Ohio. However, due to tightening environmental regulations and evolving market conditions, this is rapidly changing. Coal plants are scheduled to retire throughout the region, but many have not yet done so. Key deadlines are April 2015 and April 2016. Therefore, historic and current wholesale prices do not yet reflect the full impact of environmental regulation on the market, but soon will begin to do so. The first direct impact of these new regulations will be to raise electrical energy prices, because the variable costs of coal plants are lower than natural gas plants in most cases; so as natural gas plants replace coal, the variable costs of the plants that set market prices will increase. The second direct impact will be to decrease the supply of capacity (due to resource retirements), and thus, increase capacity prices. This impact has not fully manifested itself due to the increase in DR which has been, in part, the result of past FERC policies providing preferences to DR. The third direct impact will occur if CO_2 emission regulations increase the costs of fossil generation. As discussed below, no CO_2 regulations are yet in effect in Ohio, but national regulations have recently been proposed. Under these proposed regulations, there will be \$/ton costs for emissions that will raise the \$/MWh cost of operation. The main indirect impact will be to increase demand for natural gas, which has lower carbon emissions per unit of energy, and thereby raise natural gas prices. This, in turn, will raise electrical energy prices.

- **New FERC Policies** – New FERC policies limiting DR participation in capacity markets will increase capacity prices in those markets. While the extent of this policy change is uncertain, the effect could be very large. Also, tariff changes limiting power imports into the PJM capacity markets will also increase capacity prices.
- **Natural Gas Trends** – Supply and demand conditions in natural gas markets, including shale gas exploration and development, are important factors when evaluating potential trends in natural gas prices. While the development of shale gas is a major long-term trend that increases supply, an offsetting trend on the demand side is beginning to develop. Large investments are being made to increase the domestic use and export of natural gas, including the construction of numerous LNG export facilities, new petro-chemical facilities, export facilities for delivery to Mexico, and new natural gas-fired power plants. Once these facilities come on-line, demand will increase substantially, firming natural gas prices and putting upward pressure on power prices.
- **Demand Conditions** – As the economy continues to recover, overall energy demand growth is expected to resume. Expected demand growth will raise electrical energy prices in part because of natural gas increasingly becoming the marginal fuel. Natural gas is more costly on a variable cost basis than coal. This moves demand up the PJM energy supply curve, increasingly reaching the natural

gas cost sections of the curve (see the illustrative PJM electrical energy supply curves in Figure 4).

- **General Inflation** – General economy-wide inflation will raise nominal power production costs over time, and hence, will raise nominal wholesale electricity prices. The impact of general inflation is especially pronounced towards the end of the 20-year forecast period because of inflation's cumulative effects. For example, general inflation raises ICF's 2034 price forecast by 55% compared to a forecast for the same year in real 2013 dollars – i.e., with no general inflation.

IV. POWER PRICE VOLATILITY

Q. WHY IS PRICE VOLATILITY RELEVANT TO THE WHOLESALE MARKET PROJECTIONS?

A. When prices are more volatile, it is more difficult to make projections over the short term. Prices may change due to a wide variety of factors, including economic performance, weather, infrastructure, and changes in fuel costs. Hence, simple extrapolation becomes less appropriate.

Q. WHAT IS THE RELATIONSHIP BETWEEN WHOLESALE AND RETAIL POWER PRICING?

A. Wholesale power prices are important because wholesale power is the main input to retail power supply. Between 2015 and 2034, as the wholesale and power market prices delivered to FirstEnergy increase, retail prices will follow this trend on average.

Q. WHY IS RETAIL PRICE VOLATILITY RELEVANT?

A. All else equal, consumers and producers prefer less power price volatility. This is because volatility complicates budgeting and planning. Price volatility also increases the cost of financial hedging, which can become more challenging as volatility increases. For example, mark-to-market collateral requirements associated with some financial hedges have collateral requirements that vary as market prices vary. The growing correlation between electricity and natural gas price volatility can also increase the impact of volatility. This is because users, especially low income users, can simultaneously face higher electricity and natural gas utility bills.

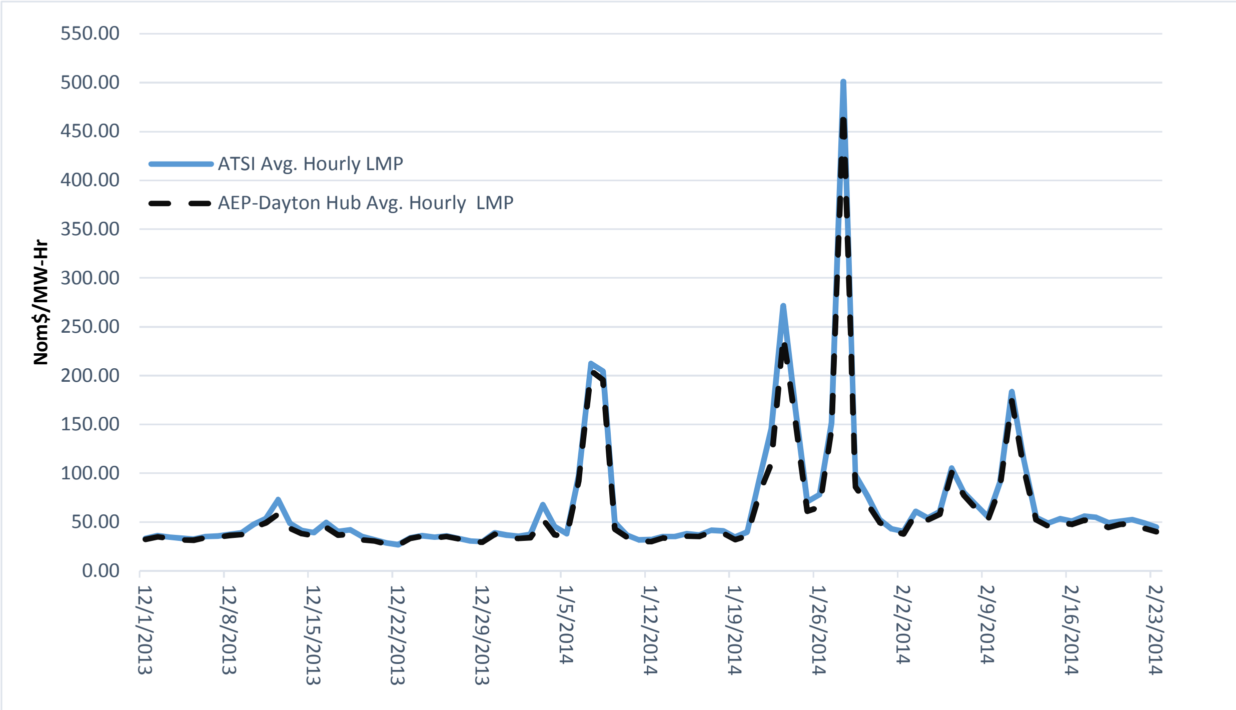
Q. HAVE PRICES IN THE ELECTRICAL ENERGY AND NATURAL GAS MARKETS BEEN VOLATILE?

A. Yes. Electricity prices have been extremely volatile, and I expect them to continue to be volatile. Events over this past winter (2013/2014) in ATSI Zone and AEP-Dayton Hub of western PJM highlight the potential for high power price volatility. Over the past winter, spot power prices in western PJM (see Figure 3 ATSI Zonal, AEP Dayton HUB electrical energy prices) reached very high levels. The volatility was largely driven by high natural gas prices, but other factors also played a role including high demand and poor power plant performance due to very cold weather (see Figure 4). The delivered natural gas prices recorded over the last winter in eastern PJM were the highest natural gas prices ever in the U.S. (see Figure 5). A critical cause of this extreme volatility in natural gas prices is the lack of firm natural gas delivery capability at many natural gas power plants. This is in contrast to coal and nuclear units, which maintain large amounts of fuel on-site. As the rest of PJM becomes more reliant on natural gas, volatility can be expected to increase, though the exact levels may vary.

Q. WHAT IS THE RELATIONSHIP BETWEEN PRICE VOLATILITY AND YOUR FORECAST?

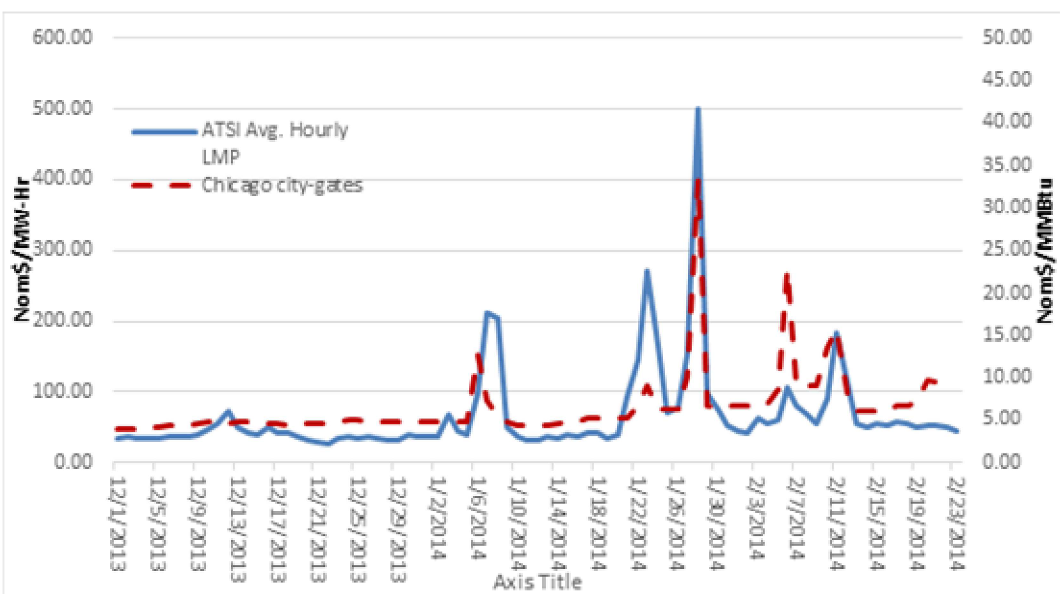
A. In the long-term, ICF forecasts expected prices. Actual prices are expected to average these prices, but can be volatile around the average.

Figure 3
Spiking Wholesale Spot Electric Prices – Western PJM



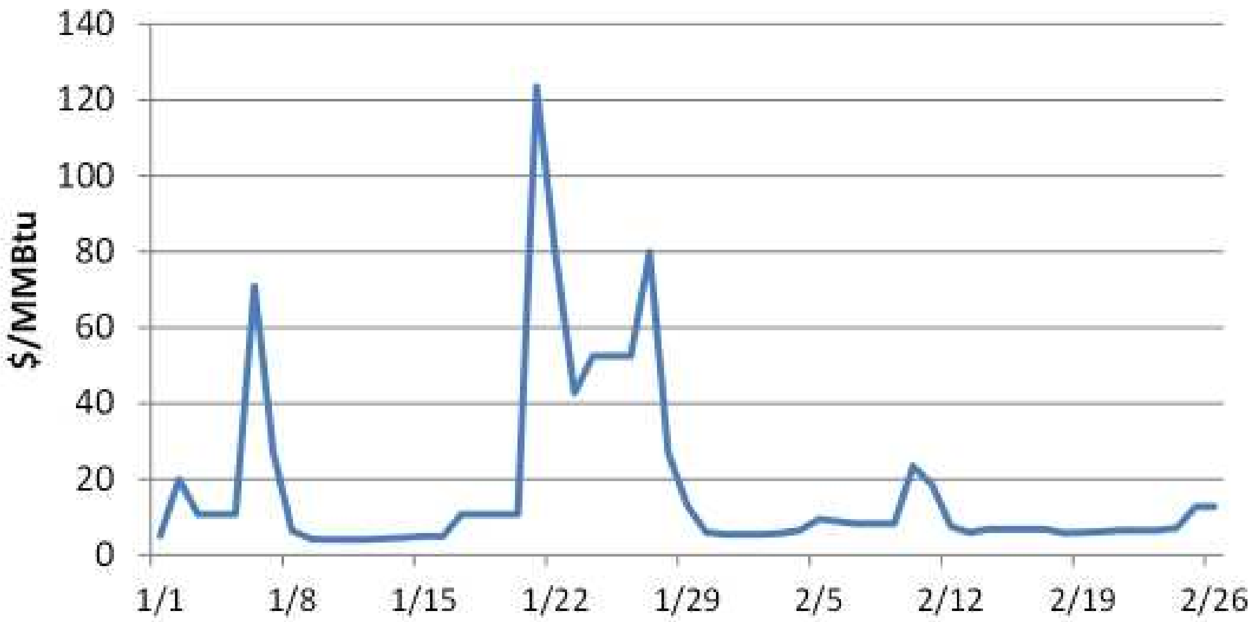
Source: SNL Financial

Figure 4
Power and Natural Gas Prices Tracking Each Other



Source: SNL Financial

Figure 5
Eastern PJM Prices Reach Highest Prices Ever Recorded in the U.S. Transco Zone 6 Non-NY



Source: SNL Financial

Q. WHY ARE WHOLESALE ELECTRICITY PRICES SO VOLATILE?

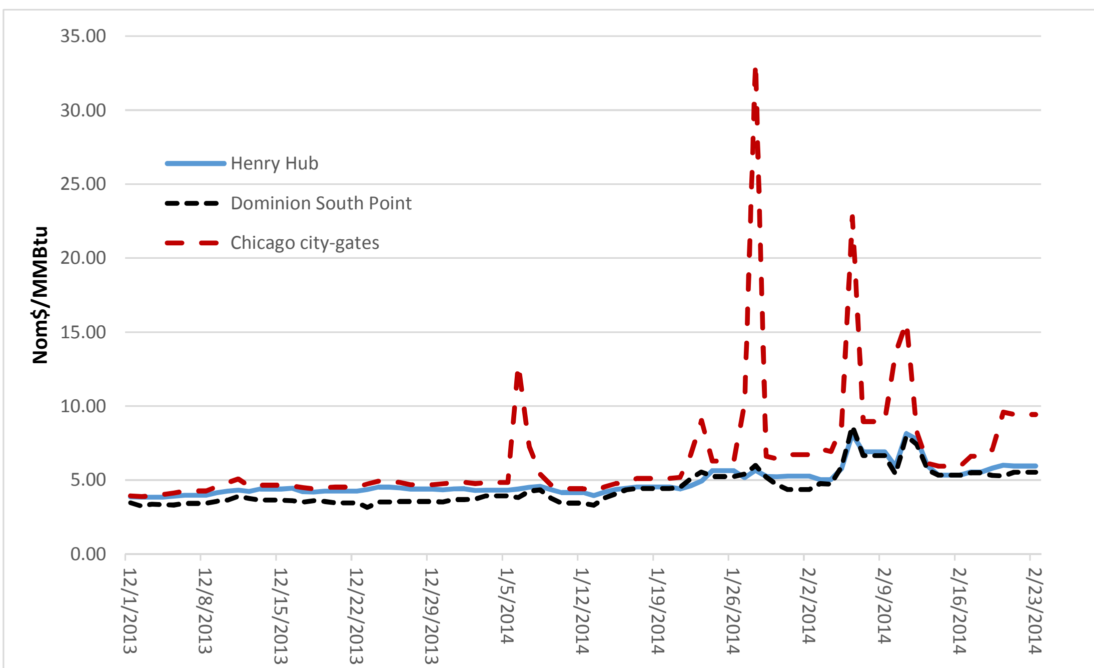
A. Electricity price volatility is due to a combination of factors:

- Electricity cannot be economically stored.
- The variable costs of generation vary widely across power plants.
- Demand fluctuates seasonally, monthly, and diurnally, so units with different marginal costs become the marginal price setting units. The diversity of the marginal price setting units in the Midwest is increasing due to coal plant retirements and growing reliance on natural gas.
- The underlying fuel markets can be very volatile, especially natural gas markets. Over the past winter, delivered natural gas prices in eastern PJM hit the highest levels in U.S. history, reaching $120/MMBtu (see Figure 5). This incredible

volatility is apparent when compared with more typical recent supply area natural gas prices: for example, Henry Hub, a Louisiana supply area and the Chicago City Gate delivery area (see Figure 6).

- A significant factor affecting volatility of electricity prices is the frequent changes to market rules and structures. For example, PJM's BRA capacity market, which is regulated by FERC, recently changed its treatment of DR and imports in the capacity market which contributed to the increase in prices in the RTO market. Additional changes are expected, as I will discuss later.

Figure 6
Spiking Western PJM Natural Gas Prices During 2013/2014 Cold Snaps Reach Very High Levels in the U.S.



Source: SNL Financial

Q. DO OTHER METRICS SUPPORT HIGH VOLATILITY FOR POWER PRICES?

A. Yes. Table 3 shows annual average prices for selected natural gas and power products, and associated annual standard deviations and coefficient of variations.[6] Both products exhibit significant volatility. Natural gas prices are more volatile on an annual basis than power prices as measured by the coefficient of variations. On a daily basis, power prices are more volatile than natural gas prices. Table 4 shows a time series of daily volatility metrics for the relevant power and natural gas markets. Using the coefficient of variation as a measure of relative volatility, it can be seen that daily power prices have a higher coefficient of variation than daily natural gas prices. Developments in 2014 include record high volatility or variance for both power price indices; year-to-date[7] 2014 prices have been the most volatile over the 2007 to 2014 period. In 2014, the volatility of power is higher in part due to weather, but also due to the impacts of high volatility in delivered natural gas prices combined with the increasing power sector reliance on natural gas as the marginal price setting fuel. In 2014, natural gas volatility was low for Henry Hub, which is the main U.S. supply hub (coefficient of variation 0.16). The coefficient of variation is much higher for the delivered natural gas price at Chicago City Gate. This price is more directly relevant to PJM than Henry Hub because Chicago is part of PJM. The volatility in the Dominion South is intermediate because it measures both supply and demand area prices. Though not shown, the coefficient of variation for Transco Zone 6 non-NY was also very high and also serves PJM.

[6] Coefficient variation is the ratio of standard deviation over the mean. Hence, it corrects the variance for different mean levels and facilitates comparison across products.

[7] Through June 5, 2014.

Table 3

Annual Volatility Metrics – Power and Natural Gas Price

Market	Type	Unit	2007 – 2014[1]		
			Average	**Standard Deviation**	**Coefficient of Variation**
AEP Dayton	Power	$/MWh	41.3	9.41	0.23
ATSI	Power	$/MWh	42.2	12.78	0.30
Henry Hub	Natural Gas	$/MMBtu	4.95	2.00	0.40
Dominion South	Natural Gas	$/MMBtu	5.05	2.19	0.43
Chicago City Gate	Natural Gas	$/MMBtu	5.22	2.03	0.39

Source: SNL Financial and ICF International

[1] 2014 is through June 5, 2014.

Table 4
Daily Volatility Metrics – Power and Natural Gas Prices

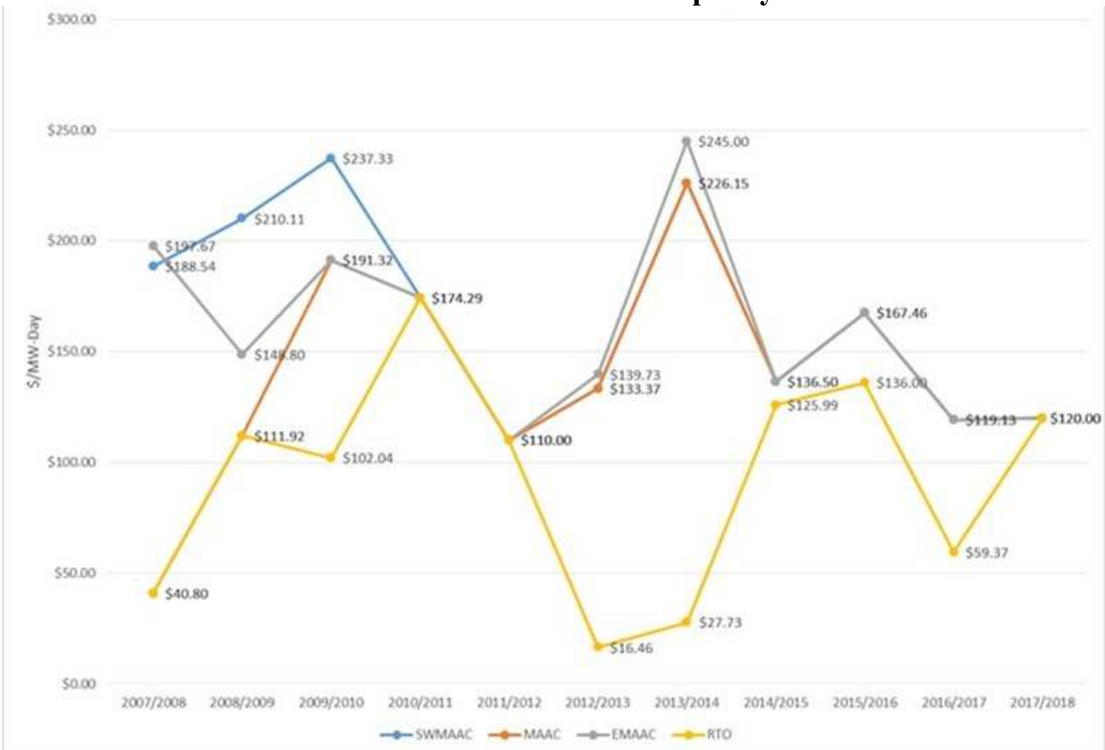
Marker	Type	Metric	Average (2007-2014)	2007	2008	2009	2010	2011	2012	2013	2014[1]
AEP Dayton	Power Price	Average Price ($/MWh)	41.3	45.2	53.2	33.0	37.6	38.7	31.2	35.0	56.6
		Hourly Standard Deviation ($/MWh)	13.9	12.0	14.5	6.75	7.61	8.92	6.04	8.11	47.3
		Coefficient of Variation	0.30	0.27	0.27	0.20	0.20	0.23	0.19	0.23	0.84
ATSI[2]	Power Price	Average Price ($/MWh)	42.2	NA	NA	NA	NA	39.3	32.1	36.5	60.9
		Hourly Standard Deviation ($/MWh)	19.8	NA	NA	NA	NA	11.4	6.6	9.6	51.6
		Coefficient of Variation	0.40	NA	NA	NA	NA	0.29	0.20	0.26	0.85
Henry Hub	Natural Gas	Average Price ($/MWh)	4.95	6.96	8.88	3.95	4.40	4.00	2.76	3.73	4.90
		Daily Standard Deviation ($/MWh)	0.80	0.72	2.09	0.83	0.70	0.47	0.48	0.32	0.77
		Coefficient of Variation	0.16	0.10	0.24	0.21	0.16	0.12	0.18	0.09	0.16
Dominion South	Natural Gas	Average Price ($/MWh)	5.05	7.41	9.33	4.26	4.60	4.13	2.78	3.52	4.38
		Daily Standard Deviation ($/MWh)	0.91	0.95	2.24	0.99	0.74	0.51	0.48	0.36	1.00
		Coefficient of Variation	0.17	0.13	0.24	0.23	0.16	0.12	0.17	0.10	0.23
Chicago City-Gate	Natural Gas	Average Price ($/MWh)	5.22	6.86	8.81	3.95	4.48	4.13	2.86	3.86	6.80
		Daily Standard Deviation ($/MWh)	1.34	0.72	2.15	0.95	0.71	0.47	0.52	0.36	4.83
		Coefficient of Variation	0.23	0.10	0.24	0.24	0.16	0.11	0.18	0.09	0.71

Source: SNL Financial and ICF International
[1] 2014 is through June 5, 2014.

Q. HAVE PRICES IN THE PJM CAPACITY MARKETS BEEN VOLATILE?

A. Yes. PJM has conducted 11 Base Residual Auctions ("BRAs") since the establishment of the Reliability Pricing Model ("RPM") capacity market design. The clearing prices since the adoption of the PJM RPM are presented in Figure 7 and Tables 5 and 6. In addition, in the case of the RTO capacity price (top row in Table 5), the ratio of the highest to the lowest RTO capacity price is approximately 11 to 1. The ratio of the highest ATSI Zone capacity price to the lowest is 19 to 1 (see last row in Table 5). The coefficient of variation on an annual basis is higher for ATSI Zone. Volatility within the ATSI zone has been higher despite fewer auctions in which the ATSI Zone price separated from the RTO price (7 auctions versus 11 auctions). The volatility of the capacity prices as a percentage of the average price is especially high. This is because prices have been low and below PJM's estimate of the Net Cost of New Entrant ("CONE") values, which have averaged \$225/MW-day - \$240/MW-day over the same period.

Figure 7
PJM Recent Historical Capacity Prices



Source: PJM-ISO

Table 5
PJM Recent Historical Capacity Prices – UCAP Price in Nominal $/MW-day (and $/kW-yr)

LDAs	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Average
RTO	41 (15)	112 (41)	102 (37)	174 (64)	110 (40)	16 (6)	28 (10)	126 (46)	136 (50)	59 (22)	120 (43)	93 (34)
MAAC	41 (15)	112 (41)	191 (70)	174 (64)	110 (40)	133 (49)	226 (83)	137 (50)	167 (61)	119 (43)	120 (43)	139 (51)
EMAAC	198 (72)	149 (54)	191 (70)	174 (64)	110 (40)	140 (51)	245 (89)	137 (50)	167 (61)	119 (43)	120 (43)	160 (58)
SWMAAC	189 (69)	210 (77)	237 (87)	174 (64)	110 (40)	133 (49)	226 (83)	137 (50)	167 (61)	119 (43)	120 (43)	166 (60)
PS-NORTH	198 (72)	149 (54)	191 (70)	174 (64)	110 (40)	185 (68)	245 (89)	225 (82)	167 (61)	219 (80)	215 (78)	189 (69)
DPL-SOUTH	198 (72)	149 (54)	191 (70)	186 (68)	110 (40)	222 (81)	245 (89)	137 (50)	167 (61)	119 (43)	120 (43)	168 (61)
PEPCO	189 (69)	210 (77)	237 (87)	174 (64)	110 (40)	133 (49)	247 (90)	137 (50)	167 (61)	119 (43)	120 (43)	168 (61)
ATSI	- (-)	- (-)	- (-)	- (-)	109 (40)	20 (7)	28 (10)	126 (46)	357 (130)	114 (42)	120 (43)	125 (45)

Source: PJM-ISO

Table 6
Annual Volatility of Capacity Prices (Nominal $/kW-yr)

Marker	Average	Standard Deviation	Coefficient of Variation
RTO	34	18	0.54
ATSI	45	41	0.90

Source: PJM-ISO and ICF International

V. ELECTRICITY PRICE PROJECTIONS – ELECTRICAL ENERGY

Q. WHAT IS THE BASIS OF YOUR CONCLUSIONS THAT WHOLESALE ELECTRICAL ENERGY PRICES WILL INCREASE OVER TIME?

A. There are three reasons that I anticipate higher wholesale power prices. First, changing trends for key price drivers discussed throughout my testimony support higher electrical energy prices. Second, forward prices in the near-term also support increasing prices. Third, computer modeling supports higher future prices. The model's projections are based on analysis of hourly supply and demand fundamentals.

Q. WHAT ARE THE FORWARD ELECTRICAL ENERGY PRICE TRENDS?

A. One basis for concluding that there will be higher prices in the future is the observable forward prices for the delivery of wholesale power to FirstEnergy. Wholesale forward prices are available from the Intercontinental Exchange ("ICE")[8] through December 31, 2019 for energy, and from the PJM RPM capacity market for capacity prices through May 31, 2018. In the case of electrical energy, by 2019, the all-hours AEP-Dayton Hub and ATSI Zone prices are \$41.0/MWh and \$41.6/MWh, respectively (see Table 7). In comparison, 2011 to 2013 average AEP Dayton Hub prices were \$35/MWh or \$6/MWh lower, and ATSI Zonal prices were \$36/MWh or \$5.6/MWh lower.

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

Table 7
Forward Electrical Energy Prices ($/MWh)

Period	Source	Year	AEP-Dayton Hub	ATSI Zone	AEP-Dayton Hub	ATSI Zone
			All-Hours Energy Price (2013$/MWh)	All-Hours Energy Price (2013$/MWh	All-Hours Energy Price (nom$/MWh)	All-Hours Energy Price (nom$/MWh
Period	Forward	2015	37.1	38.1	38.6	39.8
		2016	36.4	37.1	38.8	39.5
		2017	36.3	37.1	39.5	40.3
		2018	36.1	36.8	40.0	40.8
		2019	36.2	36.7	41.0	41.6
		2015-2019	**36.4**	**37.2**	**39.6**	**40.4**

Source: SNL Financial; forwards reflect an annual average over trade dates of 4/18/14 to 5/18/14

Q. WHAT ARE THE FORWARD CAPACITY PRICE TRENDS?

A. As shown in the previous Table 5, the trend in capacity prices for RTO have generally been increasing though the price has been volatile. The 2007/2008 price was $15/kW-yr versus $43/kW-yr for 2017/2018. The most recent PJM BRA (for 2017/2018) saw a doubling of RTO capacity prices when compared to the 2016/2017 auction. In the case of ATSI, while the most recent price trend appears more consistent as it moved from $40/kW-yr in 2011/2012 to $43/kW-yr for the 2017/2018 auction. Nevertheless, it has been more volatile as shown through the coefficient of variation in Table 6.

Q. HAVE YOU CREATED A MARKET PRICE PROJECTION FOR ELECTRICITY FOR THE NEXT 20 YEARS?

A. Yes. I have used ICF's forecast of wholesale power prices, which are based on computer modeling of the North American power grid's supply and demand fundamentals with a focus on PJM and the Ohio sub-zones. These forecasts are used for the 20-year period from January 1, 2015 through December 31, 2034. Each of the components of electricity price are discussed below.

Q. WHAT ARE THE BASIC ASSUMPTIONS UNDERLYING THE POST-2015 FORECAST OF WHOLESALE POWER PRICES?

A. The forecast of electrical energy and capacity prices reflects the following assumptions:

- The wholesale power market is competitive and efficient;
- Wholesale power prices reflect the marginal costs of supply;
- Supply decisions including entry, exit and dispatch will reflect the set of decisions that minimize the discounted costs of meeting demand subject to the need to meet demand over the model forecast horizon and already firm decisions; and
- There is no shortage of supply once excess supply is eliminated by demand growth and retirements.

Q. HOW WERE ELECTRICAL ENERGY PRICES FORECASTED?

A. Electrical energy prices reflect the marginal costs of producing electrical energy – which is mostly fuel, and to a lesser degree, variable non-fuel O&M and emission allowance prices. As discussed, there is substantial variation in marginal generation equipment and demand which creates price variation over time. These prices also reflect the impacts of transmission limitations and congestion. We used computer models to project all electrical energy prices on an hourly basis. I describe the computer models used to make these projections further below.

Q. WHAT ARE YOUR WHOLESALE FORWARD PRICES FOR ELECTRICAL ENERGY IN THE ATSI ZONE AND THE AEP-DAYTON HUB FOR THE PERIOD FROM 2015-2034?

A. My forecasts for electrical energy are shown in Attachment II on an annual average basis; the forecasts are hourly. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. HOW DO THOSE PRICES COMPARE TO RECENT HISTORICAL REAL ELECTRICAL ENERGY PRICES?

A. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] This reflects the impacts of growing demand and increasing reliance on natural gas generation, increasing real natural gas prices, and tightening environmental standards. The modeling is also forecasting that new thermal power plants are entirely natural gas-fueled, and hence, over time, natural gas market conditions increasingly determine electrical energy prices.

Q. OVER THE FORECAST HORIZON, WHICH PERIOD HAS THE FASTEST GROWTH RATE?

A. The fastest growth in prices occurs in the first five years of the forecast. There are five principal reasons for this. First, as demand grows and coal plants retire, natural gas plants increasingly become the marginal price setting generating unit in the electrical energy markets. As noted, because natural gas plants have higher variable costs than coal plants, this increases electrical energy prices. Key retirement dates are April 2015 and April 2016, and hence, the full effects of retirement will occur soon. Second, by the end of the decade, natural gas prices firm due to large increases in natural gas demand both domestic and international. Rising natural gas prices also reflect, in part, the impacts of coal plant retirements as natural gas use increases in the U.S. generation sector. The effect has not been felt yet because natural gas use requires large capital investments with significant lead times. This occurs at the same time as natural gas plants increasingly become the marginal cost-drivers for energy prices as opposed to the cheaper marginal pricing of base load coal or nuclear units. This compounds the impact. Third, national CO_2 regulations are assumed to begin, albeit at a moderate level. CO_2 allowance prices increase the variable costs of plants and increase electrical energy prices. Fourth, few new power plants are forecast to be built in western PJM. Most are built in eastern PJM. This tends to allow for more electrical energy price appreciation in western PJM, including Ohio, relative to concentrating additions in western PJM. Fifth, general inflation is assumed to be 2.1% per year. This increases prices in 2020 by approximately 16%, and by 2034 by 55% relative to real prices expressed in 2013 dollars.

VI. ELECTRICITY PRICE PROJECTIONS – CAPACITY PRICES

Q. HOW ARE ICF'S 2015-2018 CAPACITY PRICE FORECASTS FOR THE ATSI ZONE AND AD HUB DEVELOPED?

A. PJM capacity prices for January 1, 2015 to May 31, 2018 reflect actual auction results (blending auction capability year results into calendar years results) for the PJM RTO and ATSI Zone sub-regions. The capacity price variation across the two PJM sub-regions reflects the auction cleared prices for their respective Local Delivery Areas (LDAs). These capacity prices come directly from PJM's RPM BRA Results.

Q. WHY ARE YOU USING CURRENTLY AVAILABLE FORWARD PRICES FOR CAPACITY FOR THE PERIOD FROM 2015-2018?

A. There is a liquid forward market for capacity for the period from the present through May 31, 2018. This forward capacity market provides actual auction results from PJM's BRA. Therefore, I feel it appropriate to utilize this data to project capacity prices over this period.

Q. HOW ARE CAPACITY PRICES PROJECTED FOR 2018 TO 2034?

A. Projected PJM capacity prices for 2018 to 2020 reflect a transition from auction pricing to our fundamentals-based projection on January 1, 2020. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. HOW ARE ICF'S 2020-2034 CAPACITY PRICE FORECASTS DEVELOPED?

A. 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?

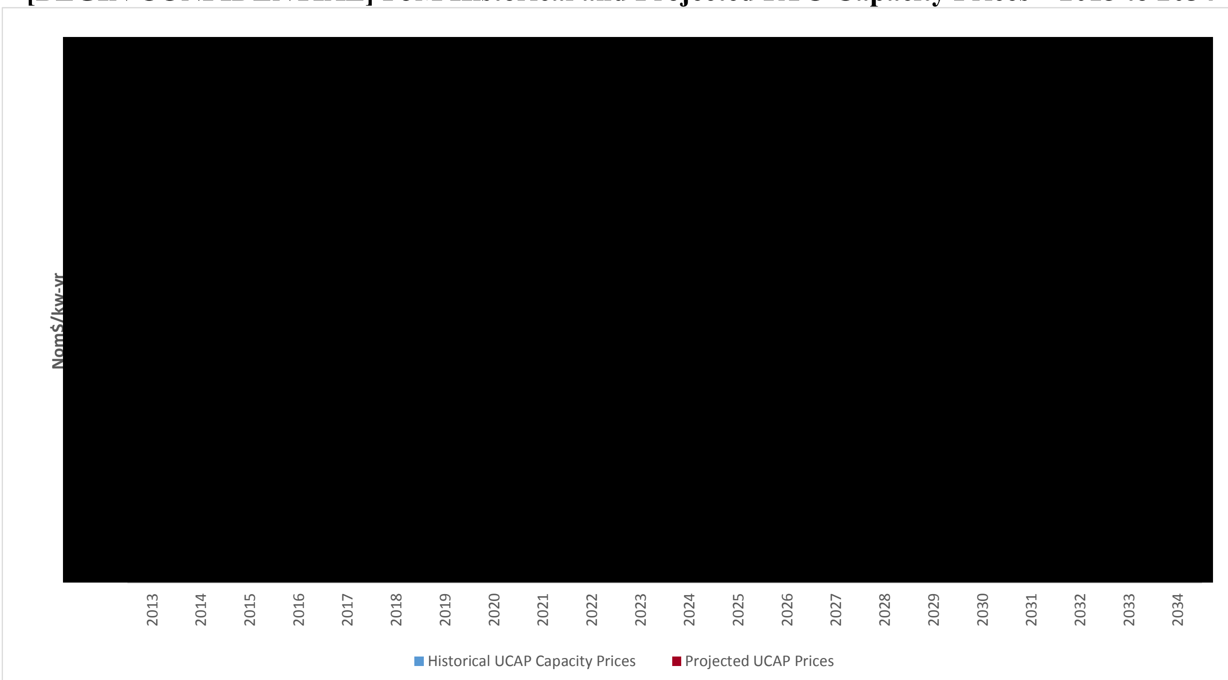
A. Demand growth and significant retirements of smaller, older coal units resulting from environment regulations are about to eliminate the excess capacity that has been in place for many years. This creates the need for new capacity. This need is increasingly occurring in western PJM. The price suppression from DR and imports is forecast to be limited compared to the past. Preferences for DR have been critical in depressing capacity prices to date. DR trends are already down reflecting new less favorable preferences. Also, historically low financing and capital costs over the last few years are expected to regress to longer-term averages, also raising capacity prices. Lastly, greater natural gas infrastructure investment over time is anticipated to cause natural gas prices to increase in northeastern PJM areas, e.g., in the areas near the Marcellus shale gas production. This, in turn, decreases the energy profits of new natural gas-fired combined cycles located near new PJM shale gas supplies, especially those in eastern PJM. Lowering energy market profits for new units increases the competitive bids for new units in the capacity market as they must compensate for lower energy earnings via higher capacity market earnings.

Q. WHAT ARE YOUR CAPACITY PRICE FORECASTS?

A. ICF's capacity price forecasts are shown in Attachment III and Figure 8. Regarding capacity prices, the RTO capacity price for delivery years 2015[9] to 2017 averages $36.8/kW-yr in real 2013 dollars, and $39/kW-yr in nominal dollars. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[9] Calendarization of 2014/2015 and 2015/2016.

Figure 8
[BEGIN CONFIDENTIAL] PJM Historical and Projected RTO Capacity Prices – 2015 to 2034



Source: Historical prices are from PJM-ISO. Projections are from ICF International

[END CONFIDENTIAL]

Q. WHY ARE CAPACITY PRICES INCREASING?

A. There are several reasons why capacity prices are forecast to increase. While these reasons primarily affect capacity prices, some of them apply to electrical energy prices as well. These reasons include:

- **Demand Resources** – In the past, the retirement of power plant capacity in PJM did not result in capacity prices similar to those forecast for most of the 2020 to 2034 period. This is because DR increased in large part due to significant past preferences provided to DR by FERC compared to generation; these preferences allowed DR to depress capacity prices. The Independent PJM Market Monitor issued a report on July 10, 2014[10] which concluded the DR (nearly all of which is interruptible load in PJM) had caused the most recent auction (held in 2014 for 2017/2018 delivery) price to decrease from $282/MW-day to $120/MW-day or from $103/kW-yr to $43/kW-yr. This is a 58% decrease in capacity prices. Put another way, the full elimination of DR would increase capacity prices by 140%. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

- **Environmental Regulations** — Environmental regulations, including Hazardous Air Pollutants ("HAPs"), CO_2, ash disposal, cooling water, and others, are expected to cause coal plant retirements, and eliminate excess capacity. PJM retirements of all types of generation capacity between 2009 and 2016 are expected to total approximately 27,000 MW. Half of this large retirement has already occurred. This loss of power plant capacity results in an increase in the value of the remaining existing capacity since buyers' next best alternative for

[10] The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses, The Independent Market Monitor for PJM, July 10, 2014, see in particular page 5.

securing capacity is new units. This also causes capacity prices to increase to allow for recovery of and on capacity for new units. As noted, the price increase due to retirements has been depressed by DR, but this is not expected to continue. Already in the last two RPM auctions, the DR trend has reversed and the amount of cleared DR has decreased.

- **Economic Recovery in the U.S. and PJM** — The economic recovery in the U.S. supports electricity demand growth and natural gas prices. As a result, there is less potential for excess capacity and more potential for stronger capacity prices.
- **Rising Financing and New Unit Capital Costs –** As discussed earlier, capital and financing costs are expected to increase from recent depressed levels.
- **General Inflation –** As discussed**,** general inflation is assumed to be 2.1% per year. Thus, compared to 2013 dollars, cumulative general inflation raises 2034 prices by 55%.
- **Import Policies –** As noted elsewhere, tighter capacity import rules will support stronger capacity prices.

VII. MODELING APPROACH AND ASSUMPTIONS

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

A. A forecast based on model projections is needed because the alternative (i.e., forwards for electrical energy) are not liquid after a few years and capacity prices are not available after 2018. The proposed Economic Stability Program extends well beyond this period.

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

A. I used two models to develop wholesale power market prices: a licensed GE-MAPS model and ICF's proprietary IPM® Model. GE-MAPS was used for the first 10 years of the forecast for electrical energy. IPM® was used for capacity expansion, capacity prices, and long-term (years 10 to 20) electrical energy forecasts. Both models forecast prices on an hourly basis, based on supply and demand fundamentals.

Q. PLEASE DESCRIBE MAPS.

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

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

Q. PLEASE DESCRIBE IPM®.

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

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

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

A. The key assumptions include:

- **Natural Gas Prices Increasing** – Natural gas prices are an important determinant of on-peak wholesale power prices in the ATSI Zone and AEP-Dayton Hub markets and will be increasingly important over time as all new thermal capacity is projected to be natural gas-fired. However, in other hours, coal generation sets prices, particularly in the off-peak and the near-term. Table 8 presents ICF's natural gas price forecast in real and nominal dollar terms. In 2015, futures for natural gas prices are $4.17/MMBtu in 2013 dollars. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

  Our approach to natural gas pricing is to use futures in the near term and transition to ICF's fundamentals-based view in 2018. Specifically, we use futures for 2015 and 2016 and, in 2018, the model reflects ICF's view of the fundamentals of the market. Beginning in 2018, natural gas prices are projected using ICF's Gas Market Model ("GMM"). GMM is a full supply/demand equilibrium model of the North American natural gas market. Our forecast is that the recent multi-year trend of low supply area natural gas prices will continue in the near-term, but over time, natural gas prices increase in real terms and even more in nominal terms. As noted, this reflects the impacts of large increases in demand as investments in equipment using natural gas come on-line (e.g., LNG exports, new petro-chemical facilities) and natural gas use in the power sector grows.

Table 8
[BEGIN CONFIDENTIAL] Henry Hub Natural Gas Prices ($/MMBtu)

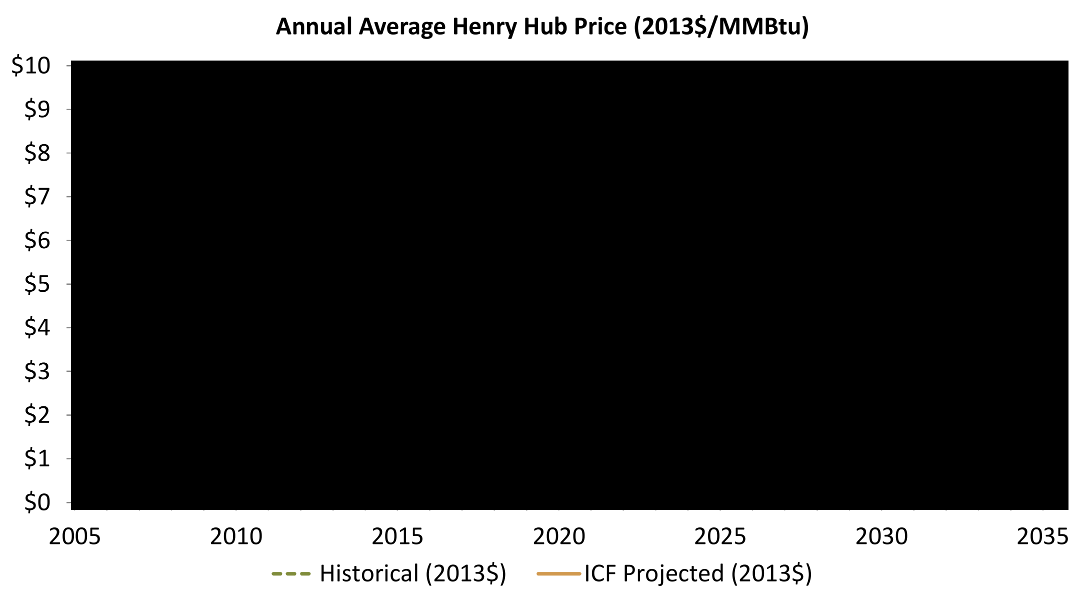
Year	Source	Real 2013$	Nominal $
2015	NYMEX Futures[1]	4.17	4.34
2016	NYMEX Futures[1]	4.02	4.28
2017	Average of Futures[1] and ICF Forecast	[redacted]	[redacted]
2018	ICF Forecast	[redacted]	[redacted]
2020	ICF Forecast	[redacted]	[redacted]
2025	ICF Forecast	[redacted]	[redacted]
2030	ICF Forecast	[redacted]	[redacted]
3034	ICF Forecast	[redacted]	[redacted]
Average 2015 – 2034		[redacted]	[redacted]

Source: Futures data are from SNL Financial. ICF Forecast is from ICF International
[1] Traded over the period April 18 2014 to May 18 2014.

[END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] In contrast, historically between 2000 and 2008, Henry Hub natural gas price averaged $7.04/MMBtu in 2013 dollars, and averaged in two years (i.e., 2005 and 2008) approximately $9.6/MMBtu to $10.0/MMBtu in 2013 dollars (see Figure 9). Our view is that abundant natural gas supplies, particularly from the development of shale gas, will continue to depress natural gas prices in the long-term relative to average prices over the 2000 to 2008 period, but natural gas prices will be above the 2009 to 2013 average (see Figures 9 and 18). Further, there will be very large year-by-year volatility due to weather and economic and industry cycles. Volatility will be especially pronounced in demand areas, also referred to as market areas, where there is an imbalance between natural gas demand and natural gas delivery infrastructure.

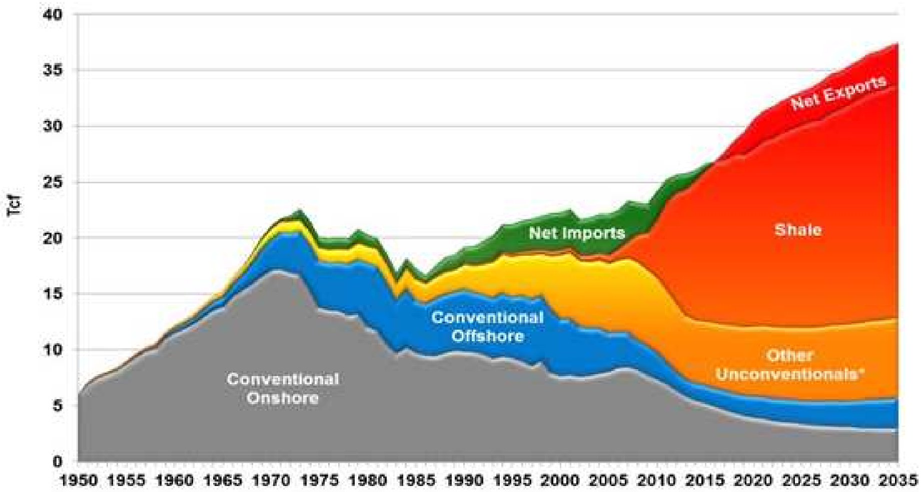
[BEGIN CONFIDENTIAL] Figure 9
Natural Gas Pricing (2013$) – Historical and ICF Forecast



Source: Futures data are from SNL Financial. ICF Forecast is from ICF International

[END CONFIDENTIAL]

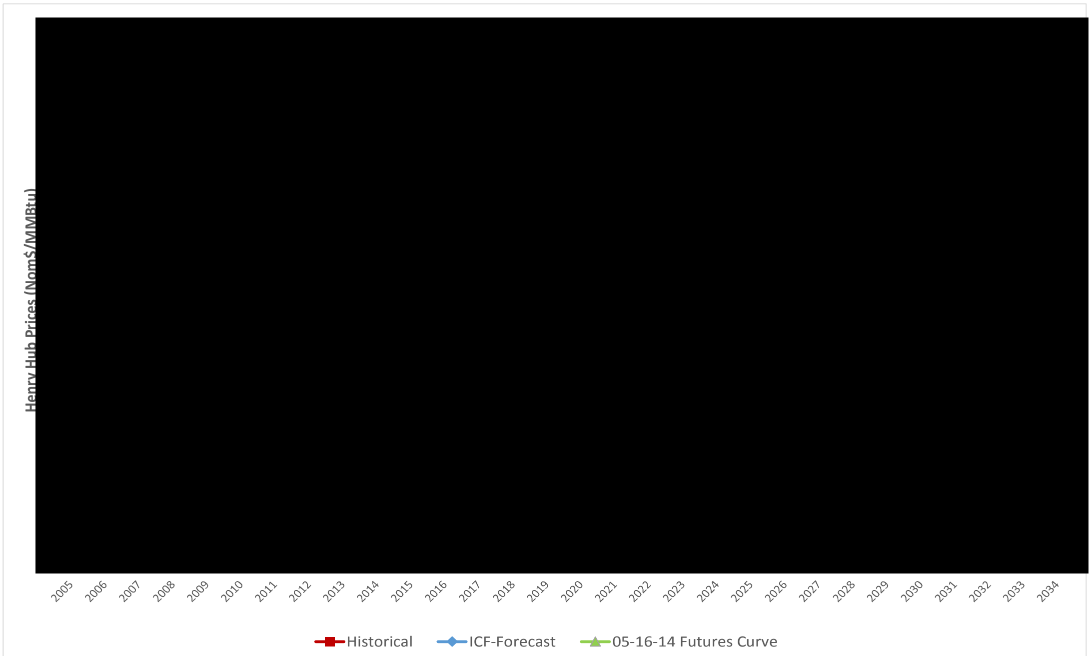
Figure 10
Natural Gas Supply



Sources: EIA and ICF estimates (1950-1999), ICF Gas Market Model (GMM)® Q2 2014 (2000-2035)
* Includes tight gas, associated gas from tight oil, and coalbed methane

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] While NYMEX futures volumes are extremely low past the prompt year (i.e., the next 12 months), and the following 1 to 2 years, ICF does not rely upon them in the mid to long-term. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The forecasts reflect ICF modeling including assumptions, model methodology, and other input data. The NYMEX futures price is very illiquid in later years and does not reflect specific supply and demand assumptions, but rather transactions. We show the NYMEX futures as a point of reference for those familiar with the NYMEX futures (see Figure 11).

[BEGIN CONFIDENTIAL] Figure 11
Natural Gas Pricing Trends over Time



Source: Historical and Futures data are from SNL Financial. Projections are from ICF International

[END CONFIDENTIAL]

- **Peak and Energy Demand Increase Moderately** – Projected peak and energy demand for PJM for the 2015 - 2034 time period are based on PJM's 2014 forecast. Regional forecasts for ATSI Zone and Dayton demand are also from PJM's 2014 forecast. Table 9 below provides an overview of the PJM RTO demand assumptions. PJM peak and energy are forecasted to grow at approximately 1.0 percent per year in the near-term from 2015-2019. Electricity demand at peak will grow at 0.8 percent per year from 2015 levels on a weather normalized basis over the 20-year period. This is lower than the average 1.4 percent growth rate between 2000 and 2007 (the last year before the Great Recession). Over the 20-

year time period, ATSI's growth is lower on average at 0.4 percent and Dayton's growth is slightly higher at 1 percent. Growth rates are calculated before accounting for DSM levels.

Table 9
PJM RTO Zone Demand Forecast

Year	Energy Demand (GWh)		Peak Demand (MW)	
	Energy	**Growth**	**Peak**	**Growth**
2015	847,743	N/A	160,259	N/A
2020	894,896		168,592	
2025	928,033		175,079	
2030	962,571		181,274	
2034	991,248		186,403	
Average 2015- 2034		**0.80%**		**0.80%**

Source: PJM-ISO, "PJM 2014 Load Forecast", February 2014

- **DR** – In PJM's most recent capacity auction for the capability period 2017/2018, DR reaches 48 percent of the planning reserves. The PJM planning reserve margin is assumed to be 15.8 percent on average. This level of DR is conservatively assumed to be maintained throughout the forecast, and therefore, will not depress capacity prices in the future to the same extent as it has in the recent past. However, there is significant uncertainty in this parameter including the potential for very large decreases in DR. A recent federal court[11] decision found that FERC cannot include demand resources in the PJM energy market. Formal complaints have been filed at FERC to similarly eliminate demand resources in the capacity markets which are also FERC jurisdictional. If the court decision is upheld, there could be a large drop in DR, which could in turn increase

[11] United States Court of Appeals for the District of Columbia Circuit, Decided May 23, 2014, No. 11-1486, Electric Power Supply Association, Petitioner vs. FERC.

capacity prices. As noted, in a July 2015 report, the PJM Independent Market Monitor (MMU) concluded that DR has played a large role in lowering capacity prices. This same conclusion is supported by its earlier April 2014 report when the PJM MMU specifically found that the 2013 PJM auction capacity price (2016/2017) would increase 184% if DR was eliminated (see Table 10). Thus, in both cases, when the MMU reviewed in detail the confidential bids and simulated the impact of DR, DR played a critical role in lowering RTO prices.

Table 10
Change in PJM RTO Cleared Capacity Prices Due to Changes in DR and Imports – 2013

Adjustment	Market Monitor Calculated Percent Increase in PJM Capacity Price in 2013 Auction
Exclusion of "Inferior Demand" Products	+84%
Require Firm Contracts for Imports	+24%
No Demand Response	+184%

Source: PJM-ISO, "PJM Market Monitor Report", April 18, 2014.

DR constituted 1.6% of the demand requirement in the 2007/08 auction, growing to 9.7% in the 2015/16 auction. The increase has been primarily driven by forward capacity market incentives (e.g., not requiring DR to bid into the energy market, but requiring power plants to bid and be subject to risks and rules governing participation, limiting required interruptions to 60 hours maximum in the summer while not limiting generation starts, duration of operation, or allowing generators to limit themselves to seasonal operation), elimination of the ILR alternative beginning in the 2012/2013 auction (ILR was an earlier interruptible load program), and expanded PJM membership and consequently increased demand, particularly in the 2013/2014 auction. As a consequence, this past winter (2013/2014), the amount of interruptible load was approximately 9,300

MW and the grid experienced scarcity and price volatility. The price volatility was due in part to only 2,000 MW of the approximately 9,300 MW of interruptible load responding (albeit voluntarily). This is largely because interruptible load is generally not required to be available in the winter. By the winter of 2015/2016, when most plants that are retiring in the near-term will be retired, the interruptible load from the BRA increases 50% relative to 2013/2014 levels to approximately 15,000 MW (see Table 11). Thus, the grid will be even more challenged than it is now, particularly for winter service.

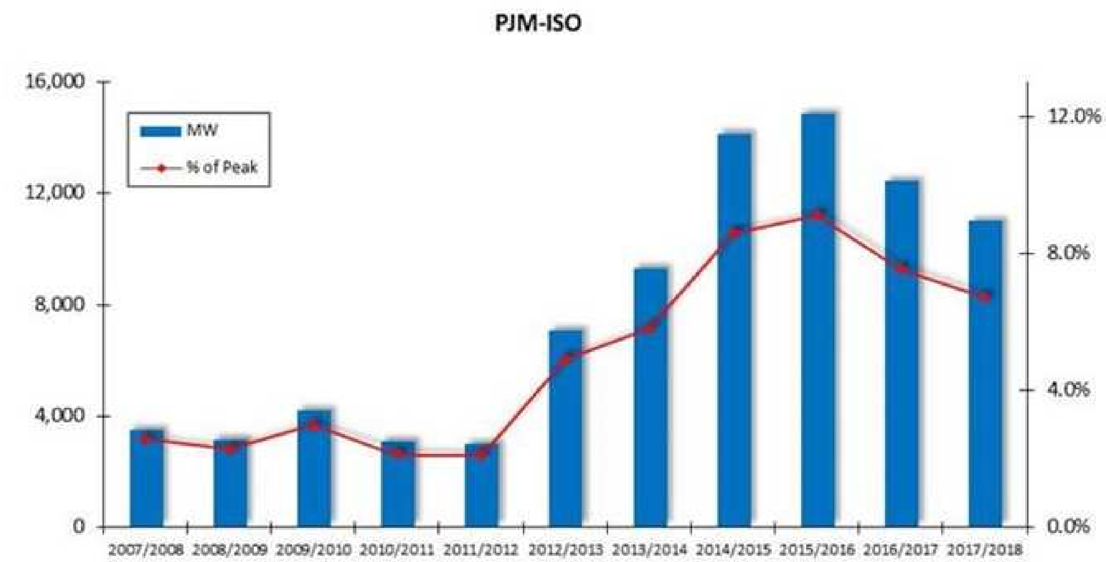
Table 11
PJM Demand Resource UCAP Participation

DR Type	7/8	8/9	9/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
ILR	2,107	2,110	2,108	2,110	1,594	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
EE Cleared	NA	NA	NA	NA	NA	569	679	822	923	1,117	1,339
Total DSM	**2,235**	**2,646**	**3,001**	**3,049**	**2,959**	**7,616**	**9,961**	**14,940**	**15,756**	**13,525**	**12,314**
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
DR as% of Demand Requirement											
% of Peak	1.6%	1.9%	2.1%	2.1%	2.1%	5.3%	6.2%	9.1%	9.7%	8.2%	7.5%
% of Target Reserves	11%	13%	14%	14%	13%	34%	39%	59%	63%	52%	48%

Source: PJM-ISO

The last two auctions have seen a decrease in DR by roughly 26%; with total DR clearing at 7.5% of peak in the 2017/18 auction (see Figure 12). This supports the conclusion that the depression of PJM capacity prices by DR is unlikely to be the same extent.

Figure 12
PJM DR Trends



Source: PJM-ISO

- **Environmental Regulations in Place to Limit CO_2** – The forecast assumes that there will be a federal CO_2 program starting on January 1, 2020. The assumed program is in the form of a cap and trade program, and reflects a probability weighted expected value (see Table 12). Specifically, ICF assessed several proposed utility sector CO_2 control programs using ICF's IPM model. ICF gave probabilities to two of these cases based on its judgment on likelihood and also gave probabilistic weight to a scenario in which there is no national CO_2 price ($/ton).

[BEGIN CONFIDENTIAL] Table 12
National CO_2 (Cap and Trade)

National CO2 (CAP & TRADE)		
Year	National CO2 Expected Allowance Prices (2013$/Ton)	National CO2 Expected Allowance Prices (Nominal$/Ton)
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]

Source: ICF International

[END CONFIDENTIAL]

No such program currently exists and, if one is not implemented, wholesale power prices will be lower than forecast. Nevertheless, progress is occurring toward a state-by-state program, lending credence to the baseline assumption of having a national CO_2 control program in place by 2020. On Monday, June 2, 2014, EPA released a proposed rule referred to as the Clean Power Plan ("CPP"), as part of President Obama's Climate Action Plan.[12] The CPP proposes to regulate CO_2 emissions from existing fossil fuel generation sources under Section 111(d) of the Clean Air Act.[13] EPA estimates that the program will reduce power sector emissions 30% below 2005 levels in 2030. Significant uncertainty remains around the specifics of what will become the final rule. EPA will take comments on the proposal for 120 days following publication in the Federal Register, and the schedule calls for EPA to release the final rule in June 2015. There may be significant changes resulting from the comment period. Significant and prolonged legal challenges are also expected, and some could be successful.

ICF's preliminary assessment of implementation by Ohio and other states of the CPP resulted in a value similar to the expected national program in the pre-2030 period.[14]

- **Environmental Regulations for non-CO_2 Emissions** – The forecast also assumes that there will be updated command and control HAPS regulations by

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[12] As background, the Clean Air Act calls on EPA to define the **Best System of Emission Reductions (BSER)** to develop the emission performance standards. In its proposal, EPA defined BSER as a combination of measures available to states, which EPA referred to as "Building Blocks".

  - For each state, EPA used 2012 generation data (latest available) to calculate a 2012 average fossil emission rate by state that served as the starting point for the development of the standards.
  - Because EPA relied on these measures in the derivation of the standards, states will have to exceed EPA's assumed levels in one block to offset shortfalls in other blocks.

[13] This section is a sub-section for existing sources under New Source Performance Standards (NSPS). "Existing" means commenced construction before January 8, 2014. EPA proposed a rule under Section 111(b) for new sources in September 2013.

[14] Individual state SIPs will be due to EPA in June 2016, but the rule allows for states to request extensions to 2017 if going it alone or 2018 if going forward as part of a multi-state group. EPA is giving itself a year to review the SIPs. Reductions not fully binding until 2030, although progress needs to be demonstrated toward interim goals starting in 2022.

2015 to 2016 such that all U.S. coal-fired power plants are required to have SO_2 scrubbers, activated carbon injection, and/or fabric filters with Dry Sorbent Injection ("DSI"). These regulations are already in place and have played a large role in the forthcoming retirement of approximately 14,000 MW in PJM and the 13,000 MW since 2009 (for a total of 27,000 MW in PJM alone). The assumption of CO_2 and HAPS regulations has important implications for natural gas prices and for the costs of fossil-fuel generation in general. The regulations increase natural gas prices as there are fewer coal plants and the costs of operating them increase faster than the costs of operating natural gas generation. This is captured in our natural gas industry modeling. Future regulations of SO_2, NO_x, coal ash and water cooling also become more stringent as described in the appendix.

- **Capital and Financing Costs for New Builds**– New combined cycle plants are assumed to be available in 2017, approximately at $1,060/kW (2013$) in the ATSI/AEP-Dayton region. In equilibrium in the long-term, an important driver of scarcity or capacity prices is the annual costs of new entry (i.e., entry by a new natural gas-fired combined cycle). New simple-cycle units are assumed to have capital investment costs that are approximately 35 percent[15] lower relative to combined cycles, depending upon the region and year of build. 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.

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

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

ICF has assessed the required rate of return for new entrants using the Capital Asset Pricing Model ("CAPM"). We have calculated the merchant cost of equity requirement ("ROE") to be approximately 13.3 percent. Ultimately, this leads to a nominal after-tax weighted average cost of capital ("WACC") of approximately 8.7 percent.

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

- **Renewables** – 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 which decreases the attractiveness of renewables, but the initiation of a national CO_2 emission control program which provides incentives for renewables. Thus, pricing reflects the impacts of renewables.

- **Coal Prices** – Coal prices are forecast to be stable in real terms on average over time. For example, northern Appalachia high sulfur 4.5 lb. SO_2/MMBtu coal prices are projected [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

VIII. CONCLUSIONS

Q. CAN YOU SUMMARIZE THE RESULTS OF THIS ANALYSIS?

A. Yes. I project that wholesale power market prices will increase over time. This conclusion applies to both energy and capacity though the increase is especially large on a percentage basis for capacity prices.

Recent historical 2009 to 2013 prices are not useful indicators of the future. This is based on several considerations. First, it is expected that many of the trends of the last few years will reverse themselves or otherwise no longer be present. Second, forward prices support higher wholesale power prices over time. Third, computer model simulations support higher prices.

<u>Electrical Energy Prices</u>

I project that in real 2013 dollars (i.e., adjusted for general inflation), the all-hours AEP Dayton electrical energy price average will increase from approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Over the same period in nominal dollars, which fully incorporates the effects of general economy-wide inflation, the AEP Dayton all-hours electrical energy price will average approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] than the 2009 to 2013 nominal price average. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The key drivers of higher electrical energy prices include:

- Moderate economic growth and moderate electricity demand growth.
- Greater reliance on natural gas plants as the marginal price setting unit. This reflects retirements and all new units being natural gas-fired.
- Natural gas price increases starting at the end of the decade.
- Federal CO_2 controls will raise generation costs and prices with the largest impacts occurring beyond 2020.

Capacity Prices

I project the RTO capacity price will [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The key drivers of higher capacity prices includes: the elimination of excess capacity due to retirements and electricity demand growth, less depression of capacity prices by DR, lower import levels due to changes in PJM rules, and higher capital and financing costs.

Volatility

Power price volatility has been significant and is expected to continue. High volatility is driven by the lack of storage, natural gas price volatility, variation in generation supply costs, and weather, industry cycles and changes in FERC regulations. Greater reliance on natural gas will increase power price volatility, especially in situations where natural gas delivery infrastructure falls behind increased natural gas consumption.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

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

ATTACHMENT I

JUDAH L. ROSE

EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

EXPERIENCE

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF International. Mr. Rose directs ICF's Wholesale Power practice and co-chairs its Energy Advisory and Solution Line of Business. Mr. Rose has approximately 35 years of experience in the energy industry including in electricity generation, fuels, environmental compliance, planning, finance, forecasting, and transmission. Mr. Rose's clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, 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. Mr. Rose has provided testimony in over 120 instances in 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. Mr. Rose has also appeared in TV interviews.

Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

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LA Times
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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

113. Rose, J.L., Wholesale power Market Price Projection in California, Infocast, California energy Summit, San Francisco, CA, May 28, 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.

2. 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.

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IX.

EMPLOYMENT HISTORY

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

ATTACHMENT II

[BEGIN CONFIDENTIAL] Attachment II
All-Hours Energy Price – 2015 to 2034

Delivery Period	ATSI Zone Price (2013 $/MWh)	AEP-Dayton Hub Price (2013$/MWh)	ATSI Zone Price (nominal $/MWh)	AEP-Dayton Hub Price (nominal[2]$/MWh)
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
Average 2015 – 2034[1]	[redacted]	[redacted]	[redacted]	[redacted]

Source: ICF International
1) Simple average across all years.
2) Assumes 2.1% general inflation per year.

[END CONFIDENTIAL]

ATTACHMENT III

[BEGIN CONFIDENTIAL] Attachment III
PJM Capacity Prices – 2015 to 2034

Delivery Period[2]	Source	ATSI Zone Price (2013 $/kW-yr	RTO Zone Price (2013$/kW-yr)	ATSI Zone Price (nominal $/kW-yr)	RTO Zone Price (nominal $/kW-yr)
2015	RPM-BRA		46.5		48.5
2016	RPM-BRA	74.9	31.7	79.7	33.7
2017	RPM-BRA	39.9	32.1	43.3	34.9
2018	RPM-BRA and ICF Forecast	[redacted]	[redacted]	[redacted]	[redacted]
2019	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2020	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2021	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2022	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2023	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2024	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2025	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2026	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2027	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2028	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2029	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2030	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2031	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2032	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2033	ICF	[redacted]	[redacted]	[redacted]	[redacted]
2034	ICF	[redacted]	[redacted]	[redacted]	[redacted]
Average 2015 – 2034[1]		[redacted]	[redacted]	[redacted]	[redacted]

Source: 2015/2016/2017 are from PJM-ISO. 2018 onwards are ICF projections or estimates.
1) Simple average across all years
2) Reflects a calendarization of the capability years.

[END CONFIDENTIAL]