OCC EXHIBIT NO. _____

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

***** PUBLIC VERSION *****

DIRECT TESTIMONY
OF
JAMES F. WILSON

On Behalf of
The Office of the Ohio Consumers' Counsel
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And

Northeast Ohio Public Energy Council
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December 22, 2014

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A1. My name is James F. Wilson. I am an economist and principal of Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

Q2. PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A2. I have thirty years of consulting experience to the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, and market power. Other engagements have included contract litigation and damages; pipeline rate cases; forecasting and market assessment; evaluating allegations of market manipulation; probabilistic modeling of utility planning problems; and a wide range of other issues arising in these industries. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission, state regulatory agencies, and a U.S. district court.

I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, California, Russia, and other regions. With regard to the PJM system, I have been involved in a broad range of market design, planning and capacity market issues over the past several years. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A3. I am testifying on behalf of the Ohio Consumers' Counsel ("OCC") and the Northeast Ohio Public Energy Council ("NOPEC").

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A4. Yes. I testified in Case No. 14-841-EL-SSO (the application of Duke Energy Ohio for approval of an Electric Security Plan); Case No. 13-2385-EL-SSO (the application of Ohio Power Company for approval of an Electric Security Plan); Case No. 12-426-EL-SSO (the application of The Dayton Power and Light Company for approval of a Market Rate Offer); Case No. 12-1230-EL-SSO (the application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for approval of an Electric Security

Plan); and Case No. 09-906-EL-SSO (the application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for approval of a Market Rate Offer). This prior testimony was on behalf of the Ohio Consumers' Counsel.

Q5. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY?

A5. In this proceeding Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company ("FE Companies") seek approval of a new electric security plan ("ESP") for the period June 1, 2016 through May 31, 2019 (the "ESP Period"). My assignment was to review the FE Companies' application, supporting testimony, workpapers, and discovery in this proceeding, focusing on the proposed Retail Rate Stability Rider ("Rider RRS"). Under this proposed rider, the FE Companies would collect from customers the costs (net of market revenues) associated with two power plants owned by an affiliate and also a contractual arrangement. I was asked to review the FE Companies' estimate of the cost to customers under the proposed Rider RRS and to provide alternative estimates; to evaluate other claimed benefits of the arrangement; to evaluate Rider RRS as a regulatory mechanism to collect the costs of these generation resources; and to make recommendations with respect to the proposed Rider RRS and potential alternative arrangements for these generation resources.

II. BACKGROUND – THE PROPOSED RIDER RRS

Q6. PLEASE DESCRIBE THE PROPOSED RIDER RRS AND ASSOCIATED POWER PURCHASE AGREEMENT ("PPA").

A6. The arrangement and proposed rider are described in the direct testimony of the FE Companies' witness Steven E. Strah. The FE Companies would purchase the output of the Davis-Besse Nuclear Power Station ("Davis-Besse") and the W. H. Sammis Plant ("Sammis"), power plants owned by subsidiaries of their affiliate FirstEnergy Solutions Corp. ("FES"). The FE Companies would also purchase an entitlement to a portion of the output of two generating plants under a PPA ("ICPA")[1] with the Ohio Valley Electric Corporation ("OVEC"). I will refer to the Davis-Besse and Sammis plants and the OVEC entitlement collectively as the "Indicated Generation".

The purchases of the Indicated Generation would be made under a proposed 15-year PPA with FES. The FE Companies would sell these resources' capacity, energy and ancillary services into the wholesale markets operated by PJM Interconnection, L.L.C. ("PJM"). The full costs of the resources plus a return on

[1] Amended and Restated Inter-Company Power Agreement ("ICPA"), available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12594881.

invested capital, net of the associated market revenues, would be recovered from customers through the proposed Rider RRS.

Q7. PLEASE DESCRIBE THE INDICATED GENERATION ASSETS.

A7. The resources are described in the direct testimony of company witness Paul A Harden. Davis-Besse is a 908 MW nuclear power plant located in Oak Harbor, Ohio that began operation in 1977. Sammis is a 2,220 MW coal-fired plant located in Stratton, Ohio that began operation in 1959. The OVEC entitlement is supplied from two coal-fired plants owned by OVEC (together with a wholly-owned subsidiary): the 1,086 MW Kyger Creek Plant at Cheshire, Ohio, and the 1,304 MW Clifty Creek Plant located near Madison, Indiana.[2] Both OVEC plants began operation in 1955.

Q8. PLEASE DESCRIBE THE FE COMPANIES' RELATIONSHIP WITH OVEC.

A8. According to OVEC's 2013 Annual Report, FES is a Sponsoring Company entitled to 4.85 percent of the capacity and energy provided by the OVEC plants; FES is also allocated the corresponding shares of OVEC fixed and variable costs.

[2] OVEC Annual Report – 2013 p. 1, available at http://www.ovec.com/FinancialStatements/AnnualReport-2013-Signed.pdf.

In addition, Ohio Edison Company and The Toledo Edison Company are shareholders with 0.85 percent and 4.0 percent of the OVEC equity, respectively.[3]

Q9. PLEASE DESCRIBE THE PROPOSED PPA BETWEEN THE FE COMPANIES AND THEIR AFFILIATE.

A9. The FE Companies would purchase all of the output of the Indicated Generation (all of the output of Davis-Besse and Sammis, and the entitlement to a portion of OVEC output) under a FERC-jurisdictional PPA for the delivery period from June 1, 2016 through May 31, 2031. The FE Companies would pay all the costs of operating the two FES plants, including depreciation, taxes and a "reasonable return on invested capital" (according to the FE Companies' witness Jay A. Ruberto's testimony at p. 3). For the OVEC entitlement, the FE Companies would pay FES' cost.

Q10. PLEASE FURTHER EXPLAIN HOW THE FE COMPANIES PROPOSE TO TREAT THE COSTS AND REVENUES FROM THESE GENERATION RESOURCES UNDER RIDER RRS.

A10. The FE Companies do not propose to use the output of the Indicated Generation to serve the loads of non-shopping customers who remain under the Standard Service Offer ("SSO"). Instead, the FE Companies plan to offer the resources'

[3] OVEC Annual Report – 2013 p. 1.

capacity, energy and ancillary services into the PJM markets. Under the proposed Rider RRS, the FE Companies would collect from customers, on a non-bypassable basis, the costs of these resources net of the capacity, energy and ancillary services market revenues earned from the sales into the PJM markets. Thus, Rider RRS could increase or decrease customer bills, depending upon whether the Indicated Generation's costs turn out to be greater or less than the associated market revenues.

III. SUMMARY AND RECOMMENDATIONS

Q11. DO THE FE COMPANIES CLAIM THERE ARE BENEFITS FROM THE PROPOSED RIDER RRS AND ASSOCIATED PPA?

A11. Yes. The FE Companies' witness Steven A. Strah claimed three types of benefits from the arrangement (p. 2):

i. He claimed it would convey "over $2 billion in potential credits" to customers over the term of the program, offsetting potential increases in electricity prices.

ii. He claimed it would provide stability and reliability to customers, by "continuing the operation of the plants

involved," and suggesting that the natural gas-fired plants that might replace them could be less reliable.

iii. He also claimed it would contribute to the "economic vitality of Ohio."

Q12. DID THE FE COMPANIES ESTIMATE THE IMPACT OF THE PROPOSED RIDER RRS ON CUSTOMER COSTS AND RATES DURING THE ESP PERIOD?

A12. Yes. The estimated annual net revenue or cost, over the 15 years of the arrangement, was shown in the FE Companies' witness Jay A. Ruberto's Figure 1 (included here as Exhibit JFW-1) and Attachment JAR-1 (revised). These estimates were based on revenue and cost calculations prepared by the FE Companies' witness Jason Lisowski, which were based on the price forecasts of the FE Companies' witness Judah Rose. I will refer to Mr. Ruberto's net cost estimate and the underlying analysis and forecasts as the FE Companies' "Rider RRS Analysis".

Q13. WHAT IS THE ESTIMATED COST TO CUSTOMERS DURING THE ESP PERIOD BASED ON THE FE COMPANIES' RIDER RRS ANALYSIS?

A13. The net cost to customers during the ESP Period would be $420 million, or $371 million on a present value basis, according to the Rider RRS Analysis. That is, the cost of the Indicated Generation output would exceed the market value by $420 million, or [redacted] per MWh of the resources' generation on average, during the ESP Period. This is the net cost that would be collected from the FE Companies' customers through the proposed Rider RRS.

Q14. WHAT IS THE ESTIMATED IMPACT ON CUSTOMERS BEYOND THE ESP PERIOD BASED ON THE FE COMPANIES' RIDER RRS ANALYSIS?

A14. According to the Rider RRS Analysis, revenues begin to exceed costs in 2019 and continue to exceed costs through 2031. On a cumulative basis from June 1, 2016 to May 31, 2031, according to the Rider RRS Analysis there is a forecast net benefit of $2 billion, or $0.8 billion on a net present value basis (Mr. Ruberto uses the estimated cost of capital, 7.85 percent, for calculating present values, and brings all costs and revenues back to 2015).

Q15. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE NET COST ESTIMATE REPRESENTED BY THE FE COMPANIES' RIDER RRS ANALYSIS.

A15. Any analysis of a resource's future costs and market revenues relies upon multiple, uncertain assumptions and forecasts, including energy, ancillary services and capacity market prices, fuel prices, environmental and other regulations, the resource's fixed costs, and the resource's operation and generation. Consequently, the results of the Rider RRS Analysis are necessarily highly uncertain. Of course, when forecasts reach many years into the future, the likelihood that they will be close to actual values becomes much lower.

The Rider RRS Analysis relies on forecasts suggesting that electricity, natural gas and capacity prices will all rise sharply in the coming years. While this might occur, these forecasts differ from those of other forecasters, and they are also out of line with market participants' expectations as reflected in forward market prices for natural gas and electric energy. In addition, because capacity prices are supposed to only provide the "missing money" not provided by energy prices, capacity and energy revenues are substitutes; so the notion that capacity and energy prices would both increase sharply at approximately the same time and remain at high levels is especially unlikely.

Consequently, I conclude that the FE Companies' Rider RRS Analysis represents an unreliable estimate of the potential future net costs to customers of the Indicated Generation through the proposed Rider RRS, due to the speculative nature of the price assumptions used in the analysis. The net cost to customers of the proposed Rider RRS would likely be much greater than suggested by the FE Companies' Rider RRS Analysis.

Q16. HAVE YOU PREPARED ALTERNATIVE ESTIMATES OF THE COST TO CUSTOMERS UNDER RIDER RRS?

A16. Yes. I prepared three alternative scenarios, where I changed only the assumed natural gas and corresponding electricity price assumptions. Under the first alternative scenario, I assume natural gas prices will rise roughly as suggested by the U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2014 "reference case" projection,[4] prepared in 2013, and energy prices change in a corresponding manner. Under this scenario, the total savings to customers would be $0.2 billion over the 15 years of Rider RRS. This compares to Mr. Ruberto's estimate of a $2 billion credit.

[4] U.S. Energy Information Administration, Annual Energy Outlook 2014 with projections to 2040, April, 2014, available at http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

Under my second alternative scenario, I assume natural gas prices follow the AEO 2014 "High Oil and Gas Resource" scenario. As I will discuss later, this may now be a more likely scenario than the AEO 2014 reference case. Under this scenario, Rider RRS would cost customers $3 billion over the 15 years of the rider.

Under my third alternative scenario, I assume natural gas prices follow the pattern reflected in current forward prices, and rise by inflation in the out years. Under this scenario, the total cost to customers would be $3.9 billion over the 15 years of the rider.

I consider the second and third of these scenarios more likely than Mr. Rose's scenario of sharply rising natural gas and electricity prices, or the now-outdated AEO 2014 reference case. Consequently, I conclude that the proposed Rider RRS is likely to be very expensive for consumers.

Q17. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE POTENTIAL BENEFIT OF RIDER RRS AS A LONG-TERM HEDGE AGAINST THE VOLATILITY OF FUTURE MARKET PRICES.

A17. Customers receiving their electric supply under the proposed Standard Service Offer will be served under one- to three-year full requirements contracts

established through periodic auctions, and, therefore, would not be exposed to substantial market price volatility. Rider RRS would add a potentially volatile element to such customers' bills.

Customers choosing competitive retail electric service would select among the available offerings according to their preferences, and could choose offerings that hedge prices and provide greater stability to the extent that is desired. For such customers, Rider RRS, which will be updated annually, could potentially move contrary to, or in the same direction as, the market-based prices they pay at any time.

I conclude that the potential for the proposed Rider RRS to act as a hedge of volatile market prices or contribute to price stability is doubtful (due to the time lag).

Over the longer-term, whether the proposed arrangement would increase or decrease customers' bills will depend upon whether the Indicated Generation's costs are greater than or less than the associated market revenues. As noted above, I expect that the costs are likely to exceed the revenues.

Q18. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING RIDER RRS AS A REGULATORY MECHANISM FOR TREATMENT OF THE INDICATED GENERATION COSTS.

A18. The proposed Rider RRS is an example of a "cost tracker" – a regulatory mechanism through which the actual costs of a function performed or undertaken by a utility are periodically passed through to customers, outside of a rate case. State regulatory commissions typically approve cost trackers under extraordinary circumstances, for costs that are largely outside the control of the utility and unpredictable and volatile, such as fuel costs. However, the FE Companies propose to recover all Indicated Generation costs, including fixed costs, variable operations and maintenance costs, and a guaranteed return on invested capital, net of market revenues, through Rider RRS. This is not an appropriate regulatory mechanism for such costs, which are neither outside utility control, nor especially unpredictable. Treating the net costs in this manner would eliminate any incentive the FE Companies might otherwise have to manage and minimize these costs and to maximize the operation of the resources and the net revenues they earn, ultimately increasing the cost to customers.

Q19. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING INCENTIVES ISSUES RAISED BY THE PROPOSED RIDER RRS.

A19. The FirstEnergy companies have a substantial amount of generation in the PJM, western PJM, and ATSI market areas. The FirstEnergy companies already have strong incentives to attempt to raise energy and capacity prices. With the revenues associated with a part of the portfolio passed through to customers through Rider RRS, the incentive to economically withhold these resources from the markets will be strengthened.

Q20. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE PROPOSED RIDER RRS AND THE TREATMENT OF THE INDICATED GENERATION COSTS.

A20. I recommend that Rider RRS be rejected. Rider RRS would shift onto customers the net cost and risk associated with the FE Companies' affiliate's ownership of generation and the contractual relationship with OVEC. This net cost could be considerable; according to the FE Companies' Rider RRS Analysis, over $400 million over the ESP Period, and it could of course be much more during and after the ESP Period. In addition, because Rider RRS simply passes the net cost through to customers, the incentive to manage the costs, and to maximize revenues, is eliminated. And any incremental price stability the arrangement might provide by serving as a type of hedge (which I consider doubtful), would be

of little value compared to the expected net cost, and risk of even higher cost to customers.

Q21. IF THE PUCO FINDS THE NOTION OF PROVIDING CUSTOMERS A LONG-TERM PHYSICAL HEDGE ATTRACTIVE, WHAT APPROACH WOULD YOU RECOMMEND?

A21. If the PUCO wishes to provide customers a long-term physical hedge, the best approach would be to identify clear objectives for the physical hedge, and then hold a competitive procurement to acquire the resources that could best provide the hedge and satisfy all other objectives of the procurement.

Q22. IF THE PUCO CHOOSES TO APPROVE RIDER RRS IN SOME FORM, DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE APPROACH?

A22. Yes. If the PUCO chooses to approve Rider RRS in some form, I recommend that it be modified to reduce the cost and risk to customers and restore some incentive to the FE Companies to control costs and maximize operation and revenue. This could be accomplished by setting a benchmark for Rider RRS net cost and using a sharing mechanism for net costs or benefits relative to the benchmark, rather than collecting 100 percent of the net cost from customers. I describe how such an incentive mechanism could be designed in the last section of my testimony.

Q23. IF THE PUCO WILL NOT APPROVE RIDER RRS AS PROPOSED, BUT IS CONCERNED ABOUT THE SURVIVAL OF THE INDICATED GENERATION, WHAT MECHANISM WOULD YOU PROPOSE?

A23. If the goal is primarily to help the Indicated Generation bridge through the next few years, an incentive mechanism structure could also be used. With this objective the incentive mechanism should share costs during the ESP Period, but then return benefits, should they occur, more rapidly to customers after the ESP Period. The arrangement could terminate once the benefits to customers reach a threshold.

Q24. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A24. The next section of my testimony describes the FE Companies' Rider RRS Analysis. In Sections V and VI I discuss the price forecasts used in the Rider RRS Analysis, and in Section VII I present my alternative scenarios of the estimated cost to customers. In Section VIII I evaluate other claimed benefits of the proposal. Section IX of my testimony discusses the proposed Rider RRS as a regulatory mechanism, and Section X describes incentive problems created by the proposed arrangement. The final section of my testimony presents my recommendations for Rider RRS and treatment of the Indicated Generation.

IV. THE FE COMPANIES' RIDER RRS ANALYSIS

Q25. HOW DID THE FE COMPANIES ESTIMATE THE DOLLAR AMOUNTS THAT WOULD BE COLLECTED FROM CUSTOMERS UNDER THE PROPOSED RIDER RRS?

A25. The Rider RRS Analysis, summarized in witness Ruberto's Figure 1 and Attachment JAR-1, is based on revenue and cost calculations by the FE Companies' witness Jason Lisowski. Mr. Lisowski used FES internal cost estimates and cost estimates provided by OVEC. For revenues, he used witness Rose's energy and capacity price forecasts and a proprietary monthly dispatch model to determine generation and revenues. Other assumptions, such as outage rates, were also provided by FES.

Q26. WHAT IS THE ESTIMATED NET COST DURING THE ESP PERIOD BASED ON THE FE COMPANIES' RIDER RRS ANALYSIS?

A26. The annual net revenue or cost, according to the Rider RRS Analysis, was shown in Mr. Ruberto's Figure 1 (included here as Exhibit JFW-1) and his Attachment JAR-1 (revised). The total cost to customers during the ESP Period is forecast to be $420 million, or $371 million on a present value basis (Mr. Ruberto uses the cost of capital, 7.85 percent, for calculating present values, and brings all costs and revenues back to 2015).

Q27. WHAT IS THE ESTIMATED NET REVENUE BEYOND THE ESP PERIOD BASED ON THE FE COMPANIES' RIDER RRS ANALYSIS?

A27. According to the Rider RRS Analysis, net revenue becomes positive in 2019 and remains positive through 2031, the last year represented in the Rider RRS Analysis. On a cumulative basis from June 1 2016 to May 31 2031, the net benefit is estimated to be $2 billion, or $0.8 billion on a net present value basis.

Q28. WHAT IS THE PRIMARY REASON THE RIDER RRS ANALYSIS SHOWS POSITIVE NET REVENUES BEGINNING IN 2019?

A28. The Indicated Generation has costs that exceed revenues at present and, according to the Rider RRS Analysis, through 2018. The costs are forecast to increase at a moderate rate over the 15-year period (3 percent per year on average[5]). The revenues include energy, ancillary services and capacity revenues. Ancillary services revenues are small. Capacity revenues are forecast to increase sharply, but are only about one-fourth of the total revenues. The primary change over the coming years, according to the Rider RRS Analysis, is the forecast large increase in energy revenues [redacted] from [redacted], for example[6]). This results from the projected large increase in energy prices; the Rider RRS Analysis has energy prices rising [redacted].

[5] Calculation based on Mr. Ruberto's Attachment JAR-1 revised.

[6] Calculation based on Mr. Lisowski's workpapers.

Q29. PLEASE COMMENT ON THE FE COMPANIES' ENERGY, NATURAL GAS AND CAPACITY PRICE ASSUMPTIONS USED IN THE RIDER RRS ANALYSIS.

A29. These price assumptions are highly speculative. As I will explain in later sections of my testimony, other projections of energy and natural gas prices are much lower, and forward electricity and natural gas prices reflect no such tendency toward large increases in the coming years.

Q30. WHAT IS THE PRIMARY DRIVER OF THE LARGE INCREASE IN ENERGY PRICES IN THE RIDER RRS ANALYSIS?

A30. The primary driver is the forecasted large increase in natural gas prices. There is a very close relationship between Mr. Rose's electricity and natural gas price forecasts, because natural gas generation is increasingly the marginal resource whose cost determines the market-clearing electricity prices. Mr. Rose notes that his models forecast that all new thermal capacity will be gas-fired, and, as a result, "… over time, natural gas market conditions increasingly determine electrical energy prices." (p. 36).

Q31. PLEASE FURTHER DESCRIBE THE RELATIONSHIP BETWEEN MR. ROSE'S FORECASTS OF ENERGY AND NATURAL GAS PRICES.

A31. Through discovery, Mr. Rose's forecasts of hourly day-ahead ("DA") energy market prices were provided.[7] Prices were provided for the ATSI pricing point (corresponding to the FE Companies' service area in northern Ohio) and the AEP-Dayton, or "AD Hub" pricing point (a more heavily-traded pricing point roughly representing the AEP and Dayton service territories). The ATSI prices are applicable to the Davis-Besse and Sammis plants, while the AD Hub prices are applicable to the OVEC plants. Exhibit JFW-2 compares the annual average DA electricity prices forecast for the ATSI point to Mr. Rose's forecast of natural gas prices at Henry Hub, which is the primary natural gas pricing point in North America. (Mr. Rose's natural gas forecast that was used in the Rider RRS Analysis is identified as the "ICF Rider RRS Forecast" to distinguish it from other ICF forecasts presented later in this testimony.)

Exhibit JFW-2 illustrates the very close relationship between Mr. Rose's forecast of increasing electricity prices and his forecast of increasing natural gas prices. As suggested by the graphic, Mr. Rose's energy prices, expressed in $/MWH, are consistently over time about [redacted] his natural gas prices, expressed in

[7] Sierra Club Set 1 RPD 28 Attachment 1 Confidential.

$/MMBtu. This relationship suggests that, on an annual average basis, the marginal, price-setting power plant at these locations has a heat rate of roughly [redacted] MMBtu per MWh, according to Mr. Rose's forecasts.

This close relationship suggests that energy prices and revenues will rise if and when natural gas prices rise, and they will rise roughly proportionally. I will use the relationship between natural gas and electricity prices reflected in Mr. Rose's forecasts later in my testimony to estimate Rider RRS costs under alternative natural gas price scenarios.

Q32. HOW ARE NATURAL GAS PRICES IN OHIO EXPECTED TO MOVE RELATIVE TO PRICES AT THE HENRY HUB POINT?

A32. While natural gas prices in Ohio are different from prices at Henry Hub, the annual average differences have been and are expected to remain [redacted], due to the interconnected North American natural gas pipeline system that connects multiple supply regions to multiple demand regions. Mr. Rose's workpapers show the basis differential ranging from [redacted]/MMBtu to [redacted]/MMBtu over 2016 to 2034, or less than [redacted] percent of the commodity price.

Q33. HOW DO THE RESULTS OF THE RIDER RRS ANALYSIS RELATE TO NATURAL GAS PRICES?

A33. The annual results of the Rider RRS Analysis closely follow the natural gas price forecast. Exhibit JFW-3 shows the relationship between the net charge to customers under Rider RRS and the natural gas forecast. It suggests that Rider RRS changes from a charge to a credit once natural gas prices rise above about [redacted]/MMBtu in 2019-2020.

Q34. HAVE YOU REVIEWED OTHER ASSUMPTIONS AND CALCULATIONS USED IN THE FE COMPANIES' RIDER RRS ANALYSIS?

A34. I reviewed some of the testimony and discovery regarding other assumptions underlying the calculations. My testimony focuses on the energy and capacity price assumptions because those assumptions are highly uncertain and drive the result.

In particular, my testimony will not address the assumptions in the Rider RRS Analysis with regard to the fixed costs of the Indicated Generation. The main issue in that regard, discussed later in this testimony, is that under the proposed Rider RRS, the FE Companies would pass all costs through to customers, after netting market earnings. Accordingly, neither the FE Companies nor FES (the owner, through affiliates, of the Indicated Generation other than OVEC) would

have any incentive to manage and minimize those costs. Whatever the forecast might be at this time, actual costs could be considerably higher and the difference would be passed through to customers. Should there be a major loss of capacity for an extended period – for instance due to new environmental or safety rules, or unexpected failure of a major component – the FE Companies would not bear the additional costs resulting from the event, or the loss of market revenues. Both impacts would be passed through to customers through Rider RRS.

V. EVALUATION OF MR. ROSE'S NATURAL GAS AND ELECTRIC ENERGY PRICE FORECASTS

Q35. HOW DOES MR. ROSE'S NATURAL GAS PRICE FORECAST COMPARE TO OTHER PROJECTIONS OF NATURAL GAS PRICES?

A35. Mr. Rose's forecast can be compared to the projections prepared by the U.S. Energy Information Administration ("EIA"), which are published every year in its Annual Energy Outlook ("AEO"). The AEO projections are prepared by a large team using EIA's National Energy Modeling System ("NEMS"). The report discusses market trends, and provides a reference case projection and several side cases that explore alternative assumptions. The AEO projections are generally based on existing laws and regulations, however, laws or regulations considered likely to take effect may also be considered in the projections.

Exhibit JFW-4 compares Mr. Rose's forecast of Henry Hub natural gas prices to EIA's reference projection of Henry Hub prices in AEO 2014, which was prepared in 2013 and initially released in December 2013. Mr. Rose's forecast is [redacted] EIA's for [redacted] period, but then [redacted] for [redacted] and beyond.

AEO 2014 also includes a "High Oil and Gas Resource" case, which reflects the recent trend of growing oil and gas reserves, discussed later in this testimony. Exhibit JFW-4 also shows this scenario, which results in substantially lower natural gas prices than the EIA reference case in nearly all years.

Q36. HOW DOES MR. ROSE'S NATURAL GAS PRICE FORECAST COMPARE TO FORWARD PRICES FOR NATURAL GAS?

A36. Exhibit JFW-4 also shows forward natural gas prices for Henry Hub, accessed December 5, 2014.[8] Trading is for a monthly contract, and prices are seasonal;

[8] Specifically, forward prices were accessed December 5, 2014 from CME Group for Henry Hub natural gas, and also the AEP Dayton Hub ("AD Hub") and ATSI price points. Natural gas prices were accessed again on December 18 and had fallen slightly, so the earlier, higher values were used. CME Group describes itself as the world's leading and most diverse derivatives marketplace. The AD Hub futures prices accessed were PJM AEP Dayton Hub Day-Ahead Calendar-Month 5 MW Futures, Peak and Off-Peak (contracts D7 and R7), available at http://www.cmegroup.com/trading/energy/electricity/pjm-aep-dayton-hub-off-peak-calendar-month-day-ahead-lmp-swap-futures_contract_specifications.html and http://www.cmegroup.com/trading/energy/electricity/pjm-aep-dayton-hub-peak-calendar-month-day-ahead-lmp-swap-futures_contract_specifications.html.

the values shown are unweighted annual averages. Mr. Rose's forecast of Henry Hub prices is [redacted] than recent forward prices.

Q37. TO WHAT EXTENT DO THE NATURAL GAS PRICE TRENDS SHOWN IN THIS EXHIBIT REFLECT INFLATION, AS OPPOSED TO CHANGES IN NATURAL GAS SUPPLY AND DEMAND?

A37. Exhibit JFW-4 shows recent projections in nominal prices, that is, it shows the actual prices anticipated in each year without correcting for anticipated inflation. Exhibit JFW-5 shows the same projections with all prices in 2012 dollars, correcting for past and anticipated inflation (I used Mr. Rose's assumption of 2.1 percent/year inflation going forward). The patterns in real prices are similar.

Q38. HOW DO MR. ROSE'S ENERGY PRICE FORECASTS COMPARE TO FORWARD PRICES FOR ENERGY?

A38. As described earlier, energy and natural gas prices are closely related in Mr. Rose's modeling. Accordingly, his energy price forecast is also [redacted] recent forward prices, as shown in Exhibit JFW-6. This exhibit compares forward prices for the ATSI pricing point, and also the more heavily traded AD Hub point where prices are very similar to ATSI prices, to Mr. Rose's forecast electricity prices.

Q39. HOW DO YOU INTERPRET THE NATURAL GAS FORWARD PRICES; DO THEY REPRESENT A FORECAST OF FUTURE PRICES?

A39. Natural gas forward prices result from market participants' actions to lock in or hedge future prices for natural gas sales or purchases. The reported forward prices summarize actual transactions for future delivery months. Both buyers and sellers value the forward price certainty that results from such transactions. The reported forward prices reflect what buyers and sellers collectively consider to be fair prices for natural gas in various future delivery months. While the forward curve is not a forecast, it reflects market participants' expectations of future prices.

Q40. IF MARKET PARTICIPANTS BELIEVED MR. ROSE'S FORECAST OF NATURAL GAS PRICES, HOW WOULD THIS BE REFLECTED IN FORWARD PRICES?

A40. If market buyers believed Mr. Rose's forecast, they would consider current forward prices for 2020 and beyond a very good deal, and seek to lock in prices at those levels. This buying pressure would raise forward prices toward the level of their expectations, as reflected in the forecast.

Similarly, if sellers believed Mr. Rose's forecast, they would be unwilling to provide hedges at the current, lower forward price levels. This behavior too would cause upward pressure on forward prices.

In addition, the owners of undeveloped natural gas assets, if they believed Mr. Rose's forecast, would slow the development of those assets, in order to shift some production out of the [redacted] period, when prices (according to Mr. Rose's forecast) are expected to be [redacted]/MMBtu, to maximize production in [redacted] and beyond, when prices are forecast to [redacted]/MMBtu. Shifting production from the [redacted] period to [redacted] and beyond would have the result of increasing near-term forward and spot market prices, and moderating expectations of prices in [redacted] and beyond.

Mr. Rose's forecast reflects an [redacted], or almost [redacted]/MMBtu, increase in the Henry Hub price from 2019 to 2020. Such a [redacted] price increase in a [redacted] would suggest either that market participants are acting irrationally (planning to produce resources in [redacted] that will be worth so much more [redacted] later), and/or that market participants are going to be surprised by some event at that time and fail to anticipate it and arbitrage away the price differential. Because market participants have the ability to arbitrage away an anticipated [redacted]

change over a [redacted] of time, it seems questionable that a forecast should include [redacted]

Q41. HOW HAVE FORECASTS OF NATURAL GAS PRICES BEEN TRENDING OVER RECENT YEARS?

A41. Forecasts of future natural gas prices have been trending downward over the past several years, primarily due to shale gas development. Exhibit JFW-7 provides a few recent EIA projections that reflect this downward trend.

In AEO 2010 prepared in 2009, EIA was expecting prices to rise to the $6/MMBtu level by about 2011. By the time of AEO 2012, EIA was expecting prices to reach the $6 level only after 2021, and to reach the $5 level in about 2018. In AEO 2014, the $6 level was again delayed, now to 2023. Again, current forward prices suggest that market participants presently do not expect annual average prices to rise above $5/MMBtu anytime soon.

Exhibit JFW-8 shows the same projections with all prices in 2012 dollars, adjusting for past and anticipated inflation.

This exhibit shows that both the EIA projections and recent forward prices do not anticipate much increase in natural gas prices on a real (inflation-adjusted) basis over the coming years.

Q42. DO YOU EXPECT THAT EIA WILL AGAIN LOWER ITS NATURAL GAS PROJECTION, IN THE FORTHCOMING AEO 2015?

A42. This would seem quite likely. In its monthly Short Term Energy Outlook, EIA has already reduced its projection for 2015 by seven percent in its December 2014 release compared to the projection from January 2014.[9] Forward prices have declined by over $.50/MMBtu since the beginning of the year. U.S. natural gas proved reserves continue to expand faster than they are produced and consumed. AEO 2015 will be released in January 2015, and will likely be lower than the projection shown in these exhibits.

Q43. PLEASE ELABORATE REGARDING RECENT TRENDS IN U.S. NATURAL GAS RESERVES AND PRODUCTION.

A43. These developments were summarized in a report by EIA released in December 2014, *U.S. Crude Oil and Natural Gas Proved Reserves, 2013.*[10] This annual

[9] EIA, *Short Term Energy Outlook*, January 2014 and December 2014 editions, Table 2 U.S. Energy Prices (showing 2015 Henry Hub Spot prices in dollars per million Btu).

[10] U.S. Energy Information Administration, *U.S. Crude Oil and Natural Gas Proved Reserves, 2013*, December 2014, available at http://www.eia.gov/naturalgas/crudeoilreserves/pdf/uscrudeoil.pdf.

report provides details on oil and natural gas *proved reserves*, defined (at p. 1) as the estimated volumes that analysis of geologic and engineering data demonstrates with reasonable certainty (meaning a probability of recovery of 90 percent or greater) are recoverable under existing economic and operating conditions.

With regard to U.S. natural gas proved reserves, the report states the following:

i. U.S. proved reserves of natural gas increased sharply in 2013 to a new record level. The increase in proved natural gas reserves in 2013 was more than double the U.S. natural gas production that year. (p. 1.)

ii. The increase in U.S. proved reserves is largely a result of the further exploration and development of the Marcellus shale region, which includes Pennsylvania, West Virginia, Ohio and New York, and other shale gas development. Ohio's neighbors Pennsylvania and West Virginia reported the largest net increases in proved reserves of all the states in 2013 (13.5 and 8.3 Trillion cubic feet, or Tcf, respectively). (p. 10.) Pennsylvania and West Virginia

were also first and second in total discoveries. At present, only Texas has greater shale gas reserves than Pennsylvania or West Virginia. p. 14, Figure 13. Ohio's proved natural gas reserves also increased substantially, by 2 Tcf. (p. 22.)

iii. In 2013, production from the Marcellus shale region was 1.3 Tcf, while the proved reserves increased 22.1 Tcf to 64.9 Tcf. (p. 15. Table 4.)

Q44. WHAT ARE THE IMPLICATIONS OF THE SUBSTANTIAL INCREASES IN PROVED RESERVES?

A44. Due to new discoveries, proved reserves have been growing much faster than production and consumption. This helps to explain why natural gas price forecasts have been coming down year by year, and why the future dates when prices are expected to cross thresholds such as $5/MMBtu or $6/MMBtu continue to be pushed out.

Q45. MR. ROSE ASSERTS THERE ARE TRENDS THAT WILL LEAD TO HIGHER NATURAL GAS PRICES IN THE FUTURE. PLEASE DISCUSS THESE TRENDS.

A45. Mr. Rose suggests there are offsetting trends, in particular, investments in the domestic use of natural gas, and in facilities for export of natural gas. He

suggests that the resulting increasing demand will firm natural gas prices. Rose testimony, p. 19.

Q46. DO THE EIA PROJECTIONS ANTICIPATE INCREASES IN DOMESTIC DEMAND AND EXPORTS?

A46. Yes they do. Exhibit JFW-9 shows the projections from AEO 2014 and AEO 2012. In AEO 2012, EIA anticipated relatively flat domestic natural gas consumption, consistent with the trend over the past several years. However, in AEO 2014 the reference projection showed rapidly growing domestic gas use, with the primary growth in the power sector. This growth is anticipated despite the increasing prices reflected in the projection.

Under the AEO 2014 High Oil and Gas Resource projection, domestic natural gas use grows at a very fast rate while natural gas prices remain at even lower levels. This suggests that strong growth in domestic natural gas demand would occur under circumstances of abundant and moderately priced supply, rather than growth in demand pulling prices significant higher, as Mr. Rose predicts.

The AEO projections also reflect that the U.S., which has for a long time been a net importer of natural gas (mainly from Canada), will become a net exporter over the coming years.

Q47. HAS MR. ROSE OR HIS FIRM, ICF INTERNATIONAL, ALSO BEEN REDUCING THEIR FORECASTS OF NATURAL GAS PRICES IN RECENT YEARS?

A47. Yes. Exhibit JFW-10 compares Mr. Rose's forecast to publicly-available projections prepared by his firm, ICF International ("ICF"), for the INGAA Foundation in 2011 and 2009.[11] The forecasts are all presented in (inflation-adjusted) 2013 dollars.

The ICF 2009 and 2011 forecasts are similar to the contemporaneous AEO 2010 and AEO 2012 projections, respectively. In 2009, ICF was expecting natural gas prices to cross $6/MMBtu (in 2013 dollars) in 2010; in 2011, ICF was only expecting that price level to be reached in 2020. Mr. Rose's forecast from early in 2014 does not expect that to happen until [redacted]

Q48. DOES ICF CONTINUE TO REDUCE ITS NATURAL GAS PRICE FORECASTS IN 2014?

A48. [redacted] ICF [redacted] its natural gas price forecasts in 2014. ICF International's [redacted] for third

[11] The INGAA Foundation, Inc., *North American Natural Gas Midstream Infrastructure Through 2035: A Secure Energy Future*, June 28, 2011 (employing the ICF April 2011 reference case; p. 2); ICF International, *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*, submitted to The INGAA Foundation, Inc., October 2009.

quarter 2014 was provided through discovery.[12] This forecast is shown in Exhibit JFW-11 and [redacted] compared to Mr. Rose's forecast in this proceeding from earlier in 2014.

Under this more recent ICF forecast, natural gas prices do not reach [redacted]/MMBtu until [redacted] The forecast used in the Rider RRS Analysis had prices reaching this level in [redacted] Under the updated forecast, natural gas prices do not reach [redacted]MMBtu until after [redacted]

Q49. WHAT DO YOU CONCLUDE REGARDING MR. ROSE'S NATURAL GAS PRICE FORECAST?

A49. It is possible that the market will be surprised, and natural gas prices will move upward, in the coming years. Natural gas prices are uncertain, and Mr. Rose's forecast is one possible scenario. However, there would not appear to be much basis for considering this a likely scenario at this time. Mr. Rose's natural gas price forecast (and his electricity price forecast, which is closely linked to the assumed natural gas prices) appear to represent a quite speculative and unlikely scenario, [redacted].

[12] OCC Set 7 RPD 66 Att. 1a and Sierra Club Set 1 RPD-23 Attachment 1 Confidential (Att. JFW-2).

Q50. WHAT DO YOU CONCLUDE REGARDING MR. ROSE'S ELECTRIC ENERGY PRICE FORECASTS?

A50. As described earlier, Mr. Rose believes, and I agree, that energy price trends will closely follow natural gas price trends. Accordingly, if natural gas prices take a different route than he predicts, energy prices will reflect that difference.

Q51. MR. ROSE ALSO PROVIDES VARIOUS REASONS WHY ENERGY PRICES WILL RISE IN THE FUTURE. ARE ANY OF THESE FORCES LIKELY TO LEAD TO A SUBSTANTIALLY DIFFERENT RELATIONSHIP BETWEEN NATURAL GAS AND ENERGY PRICES?

A51. No. Mr. Rose describes why he believes energy prices will rise rapidly, especially during the first five years of his forecast (pp. 36-37), and it primarily has to do with natural gas. He notes that natural gas plants will increasingly become the marginal price-setting generation, so energy prices will rise along with natural gas prices. He also mentions possible carbon regulations, declining reserve margins, and inflation. Carbon regulations would only accelerate the move toward gas-fired generation and the influence of natural gas prices on energy prices.

VI. EVALUATION OF MR. ROSE'S CAPACITY PRICE FORECAST

Q52. TURNING NOW TO MR. ROSE'S CAPACITY PRICE FORECAST, PLEASE PRESENT THE HISTORICAL AND FORECAST CAPACITY PRICES.

A52. Historical PJM Reliability Pricing Model ("RPM") base residual auction capacity prices for the ATSI zone and western PJM region are presented in Exhibit JFW-12. Over the past four annual auctions, with the exception of a one-time price spike in the ATSI zone, and one instance of a lower price, capacity prices have been relatively stable in the $110 to $136/MW-day range in these zones. The ATSI zone one-time price spike occurred when FirstEnergy announced the retirement of a substantial quantity of capacity only months before the RPM auction, catching the market by surprise and causing the price spike.

Mr. Rose predicts capacity prices will [redacted] in the coming years. In particular, his capacity prices [redacted] between 2017/18 (the last year for which these prices have already been determined) and [redacted]. The Rider RRS Analysis assumes capacity prices well in excess of $[redacted]/MW-day.

Q53. WHY DOES MR. ROSE EXPECT CAPACITY PRICES TO RISE SHARPLY?

A53. Mr. Rose suggests why he believes capacity prices will rise sharply at pp. 41-43 of his testimony.

i. First, he asserts that demand resources ("DR") have in the past received "preferences" provided by FERC and that this has "suppressed" capacity prices. While Mr. Rose states "we do not assume a complete elimination of DR", he suggests that DR will be sharply reduced and that this will increase capacity prices.

ii. Second, he suggests that various environmental regulations will lead to coal plant retirements, which will reduce excess capacity and raise capacity prices.

iii. Third, he suggests that economic recovery in the U.S. and in the PJM region will support electricity demand growth also reducing excess capacity.

iv. Fourth, he suggests that capital and financing costs will increase, which would tend to raise capacity prices.

v. Fifth, he mentions inflation.

vi. The sixth and final stated reason is tighter capacity import rules.

Q54. HAVE DEMAND RESOURCES SUBSTANTIALLY SUPPRESSED CAPACITY PRICES AS MR. ROSE ALLEGES?

A54. No. As evidence of the alleged price "suppression", Mr. Rose cites (p. 42) to a report by PJM's Independent Market Monitor ("IMM"), and he claims that this report "concluded the DR… had caused the most recent auction… price to decrease from $282/MW-day to $120/MW-day." However, the IMM's report reaches no such conclusion. IMM performed a simple calculation – removing all DR offers from the auction, and recalculating the clearing price, *holding everything else constant*, in particular the quantities and prices of all other offers into the auction. But as the report clearly states right on page 1, had DR not been permitted to participate in the RPM auctions, some additional new plants would have cleared, and some plants that failed to clear and retired would also have cleared. Bidding strategies would have changed. Therefore, IMM states that their calculation should be considered only a "worst case" outcome.

In any case, new rules further restricting DR's participation in the capacity market have resulted in declining quantities of cleared DR in the past two auctions, while capacity prices have not spiked as a result.

Q55. WILL DEMAND RESOURCES' CONTRIBUTIONS TO MEETING CAPACITY REQUIREMENTS BE ELIMINATED?

A55. No. As PJM has stated, "[T]here is, in fact, well-developed peak load reduction capability in the PJM Region, and PJM reasonably and prudently must take that capability into account in both its planning and capacity procurement functions."[13] If DR is not permitted to participate as a wholesale capacity resource, its contribution to resource adequacy will be recognized as a load reduction, reducing capacity requirements.

Q56. WILL COAL PLANT RETIREMENTS LEAD TO SHARPLY RISING CAPACITY PRICES IN PJM?

A56. No. The large pulse of coal retirements was seen two years ago in the RPM auction for the 2015/16 delivery year, and it was almost entirely offset by various new resources offered into that auction and into the following auction earlier this year for the 2017/18 delivery year. The majority of the anticipated retirements have already been reflected in RPM results and they had very little impact on price due to the market response.

[13] *Answer of PJM Interconnection, L.L.C. to Complaint*, Docket No. EL14-55, October 23, 2014, p. 3.

Q57. WILL RISING ELECTRICITY DEMAND LEAD TO RISING CAPACITY PRICES, AS MR. ROSE ALLEGES?

A57. No. PJM's peak load forecasts anticipate very modest peak load growth over the coming years – less than one percent per year. More importantly, PJM has been consistently over-forecasting peak load growth, and the PJM Board has recently instructed staff to address this problem. PJM staff have proposed a short-term fix for the load forecast that will be finalized at the end of December 2014, with longer-term fixes to be developed next year.[14] Consequently, PJM's peak load forecasts, which already reflect weak load growth, are likely to be further reduced.

In addition, I have doubts that PJM reserve margins will only average the target levels, as Mr. Rose assumes. Reserve margins historically have nearly always exceeded target levels, and PJM continually strives to continue that record. For example, PJM recently proposed, and FERC approved, a further shift in the RPM capacity "demand curve" that is expected to increase cleared reserves.[15]

[14] PJM Planning Committee Meeting December 4, 2014, Item 5. The draft PJM 2015 load forecast report is available at http://www.pjm.com/~/media/committees-groups/committees/pc/20141204/20141204-item-05-draft-load-report.ashx

[15] PJM Interconnection, L.L.C. *Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing*, November 28, 2014, FERC Docket No. ER14-2940-000.

Q58. WILL TIGHTER CAPACITY IMPORT RULES LEAD TO RISING CAPACITY PRICES, AS MR. ROSE ALLEGES?

A58. No. PJM implemented tighter capacity import rules in the last auction, so any impact of this has already been reflected in RPM prices.

Q59. PLEASE SUMMARIZE YOUR COMMENTS ON THE VIEW THAT CAPACITY PRICES WILL RISE SHARPLY.

A59. I consider a substantial increase in capacity prices more likely than Mr. Rose's forecasted increases in energy prices; capacity prices reflect administrative rules established by PJM, and PJM is proposing to change those rules in ways that would tend to raise prices. However, I also note that the PJM region has seen and continues to see new entry by gas-fired generation under recent capacity price levels (in the range of $110 to $136/MW-day in western PJM and ATSI). According to some financial analysts, new combined cycle power plants are economic at current capacity price levels.[16] In addition, PJM's interconnection queue currently includes 40,000 MW of proposed gas-fired power plants, in addition to many other projects. So it is not clear that the market would support sharply higher capacity prices.

[16] US Electric Utilities & IPPs, *Further Thoughts on the RPM Auction*, May 28, 2014, pp. 6-7 (evaluating the economics of entry for new combined cycle units, and concluding that the economics are "quite strong").

I also note that capacity prices, in concept, are expected to provide the "missing money", the difference between the cost to build a new power plant and its anticipated earnings in energy and ancillary services markets or through a bilateral contract. Therefore, if energy prices rise, the missing money decreases, and capacity prices should decline. So it would seem particularly unlikely that capacity and energy prices would both rise sharply at about the same time, as Mr. Rose predicts, especially when there has been adequate new entry resulting in excess capacity even at the current price levels.

VII. ESTIMATED COST TO CUSTOMERS OF THE PROPOSED RIDER RRS

Q60. HAVE YOU PREPARED AN ESTIMATE OF THE COST TO CUSTOMERS OF RIDER RRS, IF ELECTRICITY AND NATURAL GAS PRICES DO NOT RISE AS SHARPLY AS MR. ROSE PREDICTS?

A60. Yes I have. I prepared estimates under three alternative price scenarios, each of which I consider a reasonable projection that is more likely than Mr. Rose's forecast.

My alternative scenarios use alternative natural gas price projections, and assume electric energy prices rise in a corresponding manner (as suggested by Exhibit JFW-2). I left all other assumptions, including the sharp increase in capacity

prices and all cost values, unchanged, despite my doubts about some of these assumptions.

To determine the impact of alternative natural gas prices on energy prices and revenues, I used Mr. Rose's assumed natural gas price differential between Henry Hub and the locations of the Indicated Generation, and I used the implied system marginal heat rates as reflected in his forecasted energy and natural gas prices. Thus, I changed only the natural gas prices, and reflected the change in energy prices holding Mr. Rose's other assumptions unchanged.

Q61. PLEASE DESCRIBE THE THREE ALTERNATIVE NATURAL GAS PRICE SCENARIOS THAT YOU EVALUATED.

A61. The first alternative scenario assumes natural gas prices will rise according to EIA's AEO 2014 Reference Case Scenario (illustrated in Exhibit JFW-4). Under this scenario, natural gas prices rise to $5/MMBtu by 2018 and to $6/MMBtu by 2024.

Under the second alternative scenario, I assumed natural gas prices will rise according to EIA's AEO 2014 High Oil and Gas Resource Scenario (also illustrated in Exhibit JFW-4). Under this scenario, natural gas prices rise to $5/MMBtu by 2021 and reach $6/MMbtu only in about 2030.

The third alternative scenario assumes natural gas prices follow the pattern reflected in current forward prices until 2023, and then rise at the rate of inflation. Under this scenario, natural gas prices cross $5/MMBtu in 2026.

Q62. WHAT IS THE COST TO CUSTOMERS OF RIDER RRS, IF NATURAL GAS PRICES FOLLOW YOUR FIRST SCENARIO, BASED ON THE EIA AEO 2014 REFERENCE PROJECTION PREPARED IN 2013?

A62. Under this price assumption, and holding all other assumptions unchanged, the cost to customers of Rider RRS over the ESP Period would be $0.29 billion ($0.26 billion on a net present value basis).

Under this scenario, Rider RRS over 15 years would save customers a total of $0.2 billion. This compares to Mr. Ruberto's estimate of a $2 billion credit. In net present value terms, there would be a relatively small net cost ($.04 billion), rather than Mr. Ruberto's $0.8 billion credit.

Again, natural gas price forecasts continue to decline, and I expect that EIA will lower its projection when AEO 2015 is released in January 2015. So this scenario, prepared in 2013, likely overstates natural gas and electric energy prices and revenues, and understates the cost to customers of Rider RRS.

Q63. WHAT IS THE COST TO CUSTOMERS OF RIDER RRS, IF NATURAL GAS PRICES FOLLOW YOUR SECOND SCENARIO, BASED ON THE EIA AEO 2014 HIGH OIL AND GAS RESOURCE CASE, PREPARED IN 2013?

A63. Under this price assumption, and holding all other assumptions unchanged, the cost to customers of Rider RRS over the ESP Period would be $0.78 billion ($0.67 billion on a net present value basis).

Under this scenario, the total cost to customers would be $3.0 billion over the 15 years of the rider. This again compares to Mr. Ruberto's estimate of a $2 billion credit. In net present value terms, rather than Mr. Ruberto's $0.8 billion credit, Rider RRS would result in a $1.6 billion net present value cost to customers.

Q64. WHAT IS THE COST TO CUSTOMERS OF RIDER RRS, IF NATURAL GAS PRICES FOLLOW YOUR THIRD SCENARIO, BASED ON CURRENT FORWARD PRICES?

A64. Under this price assumption, and holding all other assumptions unchanged, the cost to customers of Rider RRS over the ESP Period would be $0.85 billion ($0.73 billion on a net present value basis).

Under this scenario, the total cost to customers would be $3.9 billion over the 15 years of the rider. This again compares to Mr. Ruberto's estimate of a $2 billion

credit. In net present value terms, rather than Mr. Ruberto's $0.8 billion credit, the cost to customers would be $2.1 billion.

Q65. ACCORDING TO THE SECOND AND THIRD OF YOUR ALTERNATIVE SCENARIOS, THE INDICATED GENERATION RESOURCES DO NOT PRODUCE REVENUES IN EXCESS OF THEIR COSTS OVER THE COMING 15 YEARS. DOES THIS SUGGEST THAT SOME OF THESE PLANTS MAY NO LONGER BE ECONOMIC TO OPERATE?

A65. Yes; this analysis does call into question whether these resources are economic, and it suggests that perhaps some of the plants (or some units) should instead be retired or repowered.[17] The FE Companies' witness Moul acknowledges (pp. 2-3) that the plants may not be economic and that difficult decisions about whether to continue to operate or retire the plants may be faced in the coming years.

Q66. HOW WOULD SUCH DIFFICULT DECISIONS BE MADE, IF THE PROPOSED RIDER RRS IS IN PLACE?

A66. This is a problematic aspect of the proposed arrangement. The FE Companies expect these plants to suffer losses (costs in excess of revenues) over the 2016 to 2018 period, as reflected in Mr. Ruberto's Attachment 1, and also in my

[17] Repowering is the process of replacing older power stations with newer ones, which may result in improved efficiency, increased capacity, or reduced environmental impacts.

alternative scenarios. If recent trends in the natural gas markets continue and it appears these losses will persist for several more years, it would mean some of these plants should probably be retired. But under the proposed arrangement, the FE Companies, and the affiliated owners of these generating plants, would have no incentive to make the hard choices, as they will be guaranteed full cost recovery until May 31 2031. This is a fundamental problem with the proposed Rider RRS.

VIII. EVALUATION OF OTHER CLAIMED BENEFITS OF RIDER RRS

Q67. YOU STATED THAT THE FE COMPANIES' WITNESSES CLAIM THERE ARE OTHER BENEFITS TO THE PROPOSED RIDER RRS. PLEASE SUMMARIZE THE OTHER CLAIMED BENEFITS.

A67. The FE Companies' witness Steven E. Strah claimed that the Rider RRS arrangement would benefit the FE Companies' customers, and also local and state economies. Mr. Strah claimed three types of benefits from the arrangement (p. 2):

i. He claimed it would convey "over $2 billion in potential credits" over the term of the program, offsetting potential increases in electricity prices.

ii. He claimed it would provide stability and reliability, by "continuing the operation of the plants involved", suggesting that natural gas-fired plants are less reliable.

iii. He claimed it would contribute to the "economic vitality of Ohio."

The first type of benefit pertains to the net cost of the plants, as reflected in the Rider RRS Analysis. I addressed this claim in an earlier section of my testimony. I consider Rider RRS to more likely result in a substantial cost rather than a benefit to customers. The third type of alleged benefit – impacts on local and state economies – is outside of the scope of my assignment, and I understand it will be addressed by OCC/NOPEC's witness Matthew Kahal. Consequently, in this section of my testimony I will address the second point.

Q68. WOULD RIDER RRS TEND TO STABILIZE SSO CUSTOMERS' RATES DURING THE ESP PERIOD?

A68. Rider RRS would not necessarily lead to more stable rates for SSO customers. Under the ESP, SSO customers will be served by one- to three-year full requirements contracts resulting from competitive auctions. As a result of this process, the rates SSO customers will pay will be established through blending

the results of multiple auctions held months or years in advance of delivery. The rate resulting from each auction will tend to reflect forward prices at the time of the auction plus a markup. Forward prices for delivery periods several months or a few years out tend to be fairly stable. Consequently, the rates paid by SSO customers will tend to be fairly stable over time. This has been seen in the auctions held over the past several years to serve various Ohio utilities' SSO customers.

Rider RRS will be reconciled on an annual basis. Therefore, it will result in a bill credit or charge in each year depending upon whether market prices were relatively high or low in the prior year. The Rider RRS amounts to be collected from customers in one year will tend to be positive [or negative] when PJM market prices were relatively low [or high] in the *prior* year, which would generally occur due to the peculiar weather and other conditions of that year. Thus, as SSO customers' rates change from year to year reflecting movements in forward prices, the changes in the Rider RRS amounts may move the same direction or the opposite direction to SSO rates. It cannot be assumed, therefore, that Rider RRS will tend to hedge or stabilize SSO customers' rates.

The important point is that, as described in the prior section of this testimony, Rider RRS is likely to result in a charge to customers, and to be costly to

customers over the long term. Any impact it may have on the year to year "stability" of rates is likely to be relatively unimportant to SSO customers.

Q69. FOR CUSTOMERS WHO ARE SUPPLIED BY COMPETITIVE RETAIL SUPPLIERS, WOULD RIDER RRS TEND TO STABILIZE THEIR RATES?

A69. Customers who are instead served by competitive retail suppliers may be exposed to market price fluctuations, or may pay fairly stable rates, depending upon the choices they make that reflect their preferences. The potential impact of the proposed Rider RRS on the trajectory of such customers' rates would also depend on the extent to which the Indicated Generation net costs in one year are uncorrelated or anti-correlated with the costs at which the customer will be supplied in the following year, when the Indicated Generation net costs will be collected through Rider RRS. To the extent Rider RRS amounts might be uncorrelated with market price fluctuations and tend to stabilize some customers' bills, they would do so primarily for those customers who have by their choices indicated a preference for market-based prices rather than stable prices. Again, the proposed Rider RRS would be lagged one year, so its amounts could move in the same direction or opposite direction to the rates shopping customers are paying at any time.

Customers supplied by competitive retail suppliers have made decisions about how they wish their electric supply to be priced as market prices rise and fall, balancing cost, risk, and other considerations. Rider RRS would add an additional element that might work counter to customers' desires and choices.

Q70. HAVE THE FE COMPANIES PROPOSED THAT RIDER RRS WOULD BE IMPOSED EVEN ON CUSTOMERS WHO HAVE MADE LONGER-TERM FULL REQUIREMENTS SUPPLY ARRANGEMENT?

A70. Yes. The proposal is for Rider RRS to be non-bypassable, and, therefore, all customers would pay it, even if supplied under long-term, full requirements contracts.

Q71. FOR CUSTOMERS WHO HAVE ENTERED INTO LONGER-TERM FULL REQUIREMENTS SUPPLY ARRANGEMENTS, WOULD RIDER RRS PROVIDE BENEFITS?

A71. No. Such customers are even more hedged than SSO customers.

For example, I am informed by counsel for NOPEC that NOPEC has already contracted for full-requirements retail electric supply to serve its approximately 500,000 customers through December 31, 2019.

Q72. WOULD THE PROPOSED RIDER RRS ARRANGEMENT RESULT IN "CONTINUED ACCESS TO RELIABLE POWER" THAT OTHERWISE WOULD NOT BE ACHIEVED?

A72. No; the continued access to reliable power is arranged on a broader geographical basis through the wholesale electricity markets. In particular, PJM's RPM capacity construct was put in place to ensure adequate capacity. Whether or not the FE Companies choose to retire the Rider RRS Generation, there will be sufficient reliable capacity to serve Ohio and other areas of the PJM service territory as a result of the operation of the PJM markets, including the RPM construct. If the plants are retired, new resources, which may be new power plants, demand response, or energy efficiency, will be developed; if the plants are not retired, it is likely that some new resources will be delayed.

Q73. MR. STRAH AND OTHER FE COMPANY WITNESSES INSINUATE THAT NATURAL GAS GENERATORS MAY FACE FUEL SUPPLY CHALLENGES AND BE LESS RELIABLE. WILL GAS-FIRED POWER PLANTS BE UNRELIABLE IN THE COMING YEARS?

A73. No. During the "polar vortex" event last winter there were instances of gas-fired generators that had not arranged firm fuel supply, and that were unable to acquire fuel supply during the coldest days. However, PJM has proposed new tariff rules to ensure that the power plants it relies upon for winter reliability have firm fuel

supplies.[18] Specifically, the new rules will require capacity providers to arrange firm fuel supply in order to be considered "Capacity Performance" resources eligible for capacity payments, and will impose substantial penalties for non-performance. Consequently, in the future the gas-fired power plants needed for reliability will have firm fuel arrangements.

IX. EVALUATION OF THE PROPOSED RIDER RRS AS A REGULATORY MECHANISM

Q74. WHAT TYPE OF REGULATORY MECHANISM IS THE PROPOSED RIDER RRS?

A74. The proposed Rider RRS is an example of a cost tracker – a regulatory mechanism through which the actual costs of a utility function are periodically passed through to customers, outside of a rate case. Under the proposed Rider RRS, the net costs of the Indicated Generation (all costs net of energy and capacity revenues) would be passed through to customers in their rates the following year.

[18] PJM, *Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"),* filed December 12, 2014 in FERC Docket No. ER15-623.

Q75. FOR WHAT TYPES OF COSTS ARE COST TRACKERS CONSIDERED AN APPROPRIATE REGULATORY MECHANISM FOR THEIR COLLECTION FROM CUSTOMERS?

A75. Under traditional regulation, the collection of costs from customers is subject to regulatory review through periodic rate cases. As noted in a report by the National Regulatory Research Institute ("NRRI Report"),[19] state regulatory commissions typically approve cost trackers under extraordinary circumstances, for costs that are (1) largely outside the control of the utility, and (2) unpredictable and volatile.[20] The NRRI Report notes that regulatory commissions often, but not always, also consider whether the costs are substantial and recurring.

Q76. WHY DO REGULATORY COMMISSIONS USE COST TRACKERS ONLY UNDER THESE CIRCUMSTANCES?

A76. Regulatory commissions use cost trackers for costs that are unpredictable, substantial, and outside utility control primarily to protect a utility from potentially severe financial consequences that are not a result of utility performance. Compared to traditional regulation, a cost tracker provides revenues

[19] Costello, Ken, *How Should Regulators View Cost Trackers*, National Regulatory Research Institute Report No. 09-13, September, 2009.

[20] NRRI Report, p. 8.

that adjust more rapidly and fully to increases or decreases in cost. When the costs are largely outside of the utility's control, the need for and potential value of regulatory oversight is less. However, by providing for the collection of costs from customers without the traditional regulatory process, a cost tracker results in even weaker incentives for cost control than are provided by traditional regulation.

Q77. CAN YOU PROVIDE AN EXAMPLE OF COSTS THAT MAY BE APPROPRIATE FOR COLLECTION FROM CUSTOMERS THROUGH A COST TRACKER?

A77. A common example of a cost tracker is the fuel adjustment clause, under which a utility passes through to customers the actual cost of fuel purchased for electric generation. Fuel market prices, and also fuel requirements, are largely outside utility control and these costs can be substantial and volatile.

Q78. DOES RIDER RRS ADDRESS A CIRCUMSTANCE FOR WHICH A COST TRACKER IS APPROPRIATE?

A78. No. The FE Companies' affiliates own the Davis-Besse and Sammis power plants. The FE Companies' relationship to the OVEC power plants, including the ICPA and the affiliate's partial ownership of OVEC, are also essentially equivalent to partial plant ownership. The costs (other than fuel) associated with

utility-owned power plants are typically subject to traditional regulation. The fixed costs, and variable operations and maintenance costs, are very much under the utility's control, and they are not unpredictable or volatile; consequently, they are not appropriate costs for collection from customers through a cost tracker mechanism. The fuel costs also reflect how the plants are offered into the PJM markets and, as a result, dispatched.

Q79. THE FE COMPANIES HAVE PROPOSED THAT PUCO STAFF WOULD PERIODICALLY REVIEW THE RIDER RRS GENERATION COSTS AND REVENUES. WOULD SUCH OVERSIGHT ESSENTIALLY RESULT IN TRADITIONAL COST OF SERVICE REGULATION OF THE PLANTS?

A79. No. The proposal falls far short of restoring traditional cost of service regulation. I understand this topic will be discussed in detail by OCC witness Kenneth Rose.

Q80. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY, REGARDING THE PROPOSED RIDER RRS AS A REGULATORY MECHANISM.

A80. It is not appropriate for the FE Companies to collect the net costs of the Indicated Generation output from customers through a cost tracker such as the proposed Rider RRS. This would impose the cost and risk of the assets onto customers, while eliminating incentives to control their costs.

X. INCENTIVES PROBLEMS CREATED BY THE PROPOSED RIDER RRS

Q81. YOU STATED EARLIER THAT THE RIDER RRS ARRANGEMENT WOULD CREATE PROBLEMATIC INCENTIVES. CAN YOU GIVE A SPECIFIC EXAMPLE OF THE PROBLEMATIC INCENTIVES RESULTING FROM RIDER RRS?

A81. Yes. Consider, for example, future programs to reduce power plant fixed costs. Under market arrangements, if the plant operators were able to reduce fixed costs, it would increase the profits to their owners, primarily the FE Companies' affiliate in this instance. Consequently, the plant owners would have incentives to pressure plant management to accomplish any such potential cost improvements.

By contrast, under the proposed Rider RRS, the Indicated Generation's actual costs net of market revenues would be passed through to retail customers. The plant owners operating under such arrangements would, therefore, see no benefit from any such cost reductions, and would have little if any reason to encourage management to pursue them.

Q82. THE FE COMPANIES' AFFILIATES OWN OTHER ELECTRIC GENERATION IN THE PJM MARKETS. DOES THIS RAISE ANY ISSUES WITH REGARD TO THE PROPOSED RIDER RRS?

A82. Yes. The Indicated Generation competes with the FE Companies' affiliates' unregulated generation in the PJM markets. Under Rider RRS, the FE Companies would not benefit from incremental Indicated Generation sales and net revenues, as these would pass through to customers. However, incremental output from these plants will tend to reduce the energy prices available to the other affiliated plants in the western PJM market area. Therefore, the FE Companies would have some incentive to run these plants in a manner that would benefit the affiliated unregulated generation. Specifically, they would have incentives to run them less, and to offer them at higher prices, to support higher clearing prices. This could lead to realizing less than the full value of the Indicated Generation assets in the PJM markets, and higher net costs to customers under Rider RRS. It would also tend to raise the energy prices paid by all other consumers in the same market area to the benefit of FE's unregulated affiliate.

Q83. HAVE THE FE COMPANIES DESCRIBED THE BIDDING STRATEGY THEY WILL EMPLOY FOR OFFERING THE INDICATED GENERATION INTO THE PJM MARKETS?

A83. Yes. Through discovery, the FE Companies described their bidding strategy as follows:[21]

"(b) The Companies will evaluate market conditions at the time offers are made and will implement a strategy that attempts to maximize revenue."

Q84. WOULD THIS BIDDING STRATEGY BE CONSISTENT WITH THE INTERESTS OF THE CUSTOMERS PAYING FOR THE INDICATED GENERATION THROUGH RIDER RRS?

A84. No. There are two concerns raised by the stated bidding strategy. First, it makes no sense to offer the plants in a manner that would "maximize revenue" earned by the plants. That would call for operating the plants even when they are uneconomic and market prices are below their variable cost. Perhaps this is an error, and Mr. Ruberto (the sponsor of the response) meant to state that the plants would be offered to maximize profit or net revenue. Or perhaps Mr. Ruberto was referring to maximizing revenue across the larger portfolio including all FirstEnergy companies.

[21] Response to NUCOR Set 1 INT-51.b (Att. JFW-3).

The second concern is the suggestion that offers will be based upon "market conditions at the time offers are made." This is not competitive conduct. Acting competitively in short-term markets, offers are based on marginal or avoidable cost and this does not change with market conditions. "Market conditions" do not influence offer strategies in short-term market for firms acting competitively.

Q85. WOULD YOU EXPECT THE FE COMPANIES TO ALWAYS MAKE COMPETITIVE OFFERS IN THE PJM MARKETS?

A85. No. FirstEnergy affiliates own a considerable amount of capacity in PJM, in western PJM, and especially in the ATSI region. In light of these substantial holdings, it does make sense for FirstEnergy companies to consider "market conditions" in formulating bidding strategies, to maximize shareholder value. Offering some capacity at higher prices, for example, can contribute to higher clearing prices earned by the rest of the portfolio. Such economic withholding can be profitable for a company such as FirstEnergy with a large portfolio even if it reduces total sales somewhat. The stated bidding strategy seems to acknowledge that the FE Companies will attempt to exercise market power at times.

Q86. HOW WOULD THE PROPOSED RIDER RRS ARRANGEMENT AFFECT THE FIRSTENERGY COMPANIES' INCENTIVES TO ATTEMPT TO RAISE MARKET CLEARING PRICES IN THE PJM MARKETS?

A86. The proposed Rider RRS arrangement would expand the FirstEnergy Companies' collective incentive to raise market-clearing prices in the PJM markets. The downside of any economic withholding strategy is the lost revenue for the capacity that is economically withheld. Economic withholding is profitable when the increased revenues earned by the rest of the portfolio more than offset the lost revenue on the withheld capacity. However, under Rider RRS, the revenues earned by the Indicated Generation in energy and capacity markets would be passed through to customers. Consequently, economically withholding this capacity would cause the FirstEnergy Companies no loss at all, while it would at times contribute to higher market-clearing prices earned by the remainder of the portfolio.

Q87. HAVE THEIR BEEN INSTANCES IN THE PAST WHEN FIRSTENERGY COMPANIES OFFERED CAPACITY IN A MANNER THAT RAISED MARKET CLEARING PRICES?

A87. [redacted] In the RPM base residual auction for the 2016/17 delivery year, [redacted] despite the clearing price of $114.23/MW-day for the ATSI region, well above the RPM clearing price for the surrounding "Rest of

PJM" region.[22] This indicates that [redacted]

In general, when existing capacity fails to clear in a RPM base residual auction, this means the capacity price does not support continued operation of the plant and it will be retired or at least mothballed. However, in this instance [redacted]

On first glance it would appear to make little sense to [redacted]

Under Rider RRS, offering the Indicated Generation at prices that fail to clear would be more profitable for the FirstEnergy Companies, as there would be no lost revenue to the companies as a result of the economic withholding of this generation.

[22] Response to OCC Set 8 RPD-67 Competitively Sensitive Confidential Attachment 1 (Att. JFW-4).

XI. RECOMMENDATIONS REGARDING RIDER RRS AND THE INDICATED GENERATION

Q88. WHAT DO YOU RECOMMEND WITH REGARD TO THE PROPOSED RIDER RRS AND THE ASSOCIATED PPA?

A88. I recommend that the PUCO simply deny the FE Companies' request for Rider RRS and the associated PPA, finding that the costs and risks of the Indicated Generation should not be imposed on customers. The proposed Rider RRS would shift the costs and risks associated with the Indicated Generation to customers, while eliminating the owners' incentives to manage the costs and risks of these plants, and that should not be allowed.

Q89. IF THE PUCO FINDS THE NOTION OF PROVIDING CUSTOMERS A LONG-TERM PHYSICAL HEDGE ATTRACTIVE, WHAT APPROACH WOULD YOU RECOMMEND?

A89. If the PUCO wishes to provide customers a long-term physical hedge, the best approach would be to hold a competitive procurement. First, the PUCO would identify the objectives of the procurement and the criteria for evaluating proposals. For example, the evaluation of offered resources might consider environmental characteristics, reliability and fuel supply, fuel and resource diversity, and operational flexibility, in addition to cost and other characteristics.

Q90. IF THE PUCO DOES NOT DENY THE FE COMPANIES' REQUESTED RIDER RRS APPLICABLE TO THE INDICATED GENERATION, ARE THERE WAYS THAT THE ARRANGEMENT COULD BE MODIFIED TO AT LEAST PARTIALLY ADDRESS SOME OF THE CONCERNS YOU HAVE RAISED?

A90. Yes. A less preferred option to rejecting Rider RRS would be to modify it so that it is cost-neutral for customers, at least in an ex ante, forecast expected value sense, and so that the actual net cost or benefit of the Indicated Generation would be shared between the FE Companies and customers. Such a sharing rule would provide customers some protection, and would also restore some of the incentives to the FE Companies to maximize revenues and minimize costs that Rider RRS, as proposed, eliminates.

Q91. PLEASE ELABORATE ON HOW SUCH A SHARING RULE MIGHT WORK.

A91. A sharing rule could take the form of a typical incentive mechanism. First, a "benchmark" for the Indicated Generation net cost would be established. The benchmark could be established based on a one-time projection of the resources' expected market value, or it could be determined based on a formula that takes into account actual market prices and perhaps other uncertainties over time.

Then if the actual Indicated Generation net cost in a year equals the market-based benchmark value, Rider RRS would be zero and have no effect. Whenever actual net cost differs from the benchmark, the sharing rule would take effect. For instance, the sharing rule might call for half of the net cost or benefit relative to the benchmark to be passed through to customers through Rider RRS, with half retained by the FE Companies.

Under this approach, in effect, the FE Companies would be rewarded through Rider RRS when the Indicated Generation is valuable relative to the market-based benchmark, and the FE Companies would bear half the cost when it is costly relative to the benchmark. But the risk to the FE Companies would be reduced by sharing the cost or benefit relative to the benchmark 50/50 with customers. The cost and risk to customers would similarly be reduced by centering the arrangement on a market-based benchmark (so there is no built-in subsidy), and imposing only 50 percent of the cost or benefit relative to the benchmark on customers.

Q92. WHAT ARE THE ADVANTAGES OF THIS APPROACH COMPARED TO RIDER RRS AS THE FE COMPANIES HAS PROPOSED IT?

A92. There are three advantages to this modification of Rider RRS.

i. First, by establishing in advance an explicit benchmark (or benchmark formula) based on expected market conditions, there is no built-in subsidy or ex ante expected amount to be collected from customers through Rider RRS. While the FE Companies suggest that the arrangement will result in a net benefit to customers over its 15-year term, using more reasonable forecasts in the estimate results in a substantial expected cost to customers, as explained in an earlier section of this testimony. If the benchmark reflects an unbiased estimate of the expected market value, the expected cumulative value for customers over the ESP Period of Rider RRS would be zero, at least at the time it is established (the FE Companies would bear the expected cost of the arrangement).

ii. Second, as a result of the sharing rule, the FE Companies would have more incentive to maximize revenues and minimize costs, incentives that are eliminated under the proposed Rider RRS.

iii. Third, the risk to customers would be 50 percent mitigated by such a sharing rule, compared to the proposed Rider RRS (in addition to removing the subsidy).

Q93. THE FE COMPANIES' WITNESS MOUL STATES THAT NEAR-TERM PRICE FORECASTS ARE "UNFAVORABLE", AND WHILE PRICES ARE FORECAST TO INCREASE, THE PLANTS "MAY NOT SURVIVE" TO SEE THE "BETTER DAYS" WITHOUT RIDER RRS. (P. 2.) WOULD YOUR PROPOSED SHARING RULE ADDRESS THIS?

A93. No. The proposed sharing rule would be based around the forecast market value of the assets, which would reflect the unfavorable near-term circumstances. It would not provide the near-term subsidy that Mr. Moul suggests is needed.

Q94. PLEASE COMMENT ON MR. MOUL'S SUGGESTION THAT THE INDICATED GENERATION NEEDS HELP OR IT MAY NOT SURVIVE TO THE BETTER DAYS.

A94. This seems doubtful if in fact the owners consider the generation economic. FirstEnergy is a very large company (market capitalization approximately $16 billion) in the business of building generation and transmission, among other activities. For such facilities, enormous costs are incurred up front and recovered over decades of service.

According to Mr. Ruberto's Attachment JAR-1 (revised) reflecting the FE Companies' Rider RRS Analysis based on Mr. Rose's forecasts, the net cost of the Indicated Generation would total $404 million through 2018 on a net present value basis. However, in the subsequent years, revenues would exceed costs, reaping a present value benefit of $1,173 million over the remaining twelve years (for a present value net benefit over the entire period of $770 million). If FirstEnergy is unwilling to invest $404 million over the next four years to reap a net $770 million benefit, it is in the wrong business.

Q95. IF THE PUCO WILL NOT APPROVE RIDER RRS AS PROPOSED, BUT WOULD LIKE TO HELP THE INDICATED GENERATION SURVIVE THROUGH THE NEAR-TERM TO THE POSSIBLE BETTER DAYS, WHAT MECHANISM WOULD YOU PROPOSE?

A95. If the goal is primarily just to help the generation bridge through the next few years, an incentive mechanism structure could also be used, but the structure should be different. One approach could be the following. During the ESP Period, Rider RRS would operate as the FE Companies have proposed, except that 50 percent of the net cost or benefit of the Indicated Generation rather than 100 percent would be collected from customers through the Rider. This would result in customers providing a partial subsidy during the ESP Period.

After the ESP Period, the sharing rule would change to 25 percent to customers for annual net costs and 75 percent for net benefits. This asymmetric sharing rule would continue until such time as customers were made whole for the cost and risk incurred in the first years of the arrangement, if this ever occurs. For instance, the termination rule might call for Rider RRS and the associated PPA to terminate once the net present value of the benefits to customers reached 50 percent of the maximum cumulative present value net cost to customers during the ESP Period. If the termination condition is never met, customers would continue to asymmetrically share in the net costs or revenues for a maximum of 15 years.

Q96. WHAT WOULD BE THE ADVANTAGES OF THIS APPROACH?

A96. There are two advantages to this approach.

i. First, the FE Companies and/or their affiliate would incur only 50 percent of the net cost of the Indicated Generation during the coming years, helping them through this difficult period. Customers would incur the other 50 percent.

ii. Second, customers might eventually realize a net benefit to the arrangement, if indeed prices rise such that the Indicated Generation becomes economic.

This approach would result in some incentives to maximum revenues and control costs, and it would potentially result in the Rider RRS and PPA terminating earlier than the proposed 15 year term, returning all cost and revenue responsibility to the owners.

In addition, compared to the FE Companies' proposal, this approach might better accommodate a difficult decision to retire some or all of the Indicated Generation in the coming years.

Q97. DO YOU RECOMMEND THE PUCO CONSIDER THESE ALTERNATIVE APPROACHES?

A97. No. I recommend that the proposed Rider RRS be rejected and none of the cost and risk of the Indicated Generation be imposed on customers in any form.

XII. CONCLUSION

Q98. DOES THIS COMPLETE YOUR PRE-FILED TESTIMONY?

A98. Yes it does. However, I understand that I may be asked to update or supplement my testimony based on new information that may become available.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of James F. Wilson, PUBLIC VERSION, on Behalf of the Office of the Ohio Consumers' Counsel and Northeast Ohio Public Energy Council* was served via electronic transmission this 22th day of December, 2014 upon the parties below.

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