EXHIBIT NO. _____

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc.	)))	Case No. 20-167-EL-RDR

PUBLIC VERSION

DIRECT TESTIMONY OF DEVI GLICK

On Behalf of the
The Office of the Ohio Consumers' Counsel
65 East State Street 7th floor
Columbus, Ohio 43215

October 26, 2021

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME AND OCCUPATION.

A1. My name is Devi Glick. I am a Principal Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q2. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A2. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q3. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A3. At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include

power plant economics, power plant operations in organized electricity markets, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in Arizona, Connecticut, Florida, Indiana, Michigan, Nevada, New Mexico, North Carolina, South Carolina, Texas, Virginia, and Wisconsin. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as DG-1.

Q4. DO YOU HAVE ANY EXPERIENCE WITH THE PJM AND MISO ELECTRICITY MARKETS?

A4. Yes, I have evaluated how utilities commit and operate their power plants in the PJM and MISO electricity markets across multiple states, including Indiana, Michigan, Minnesota, and Wisconsin, for expert testimony and expert reports.

Q5. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A5. I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

Q6. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF OHIO ("PUCO")?

A6. No.

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A7. In my testimony for this proceeding, I review the costs charged in 2019 to Duke Energy Ohio's ("Duke" or "the Company") by the Ohio Valley Electric Corporation ("OVEC") under the Inter-Company Power Agreement ("OVEC Agreement"), the revenue that Duke receives for selling the power into the PJM market, and the resulting costs and revenues passed on to Duke consumers through the Price Stabilization Rider. Next, I review Duke's projections for how

much it would charge consumers under the Price Stabilization Rider in 2019 and compare those projections to the costs it actually paid. Finally, I review the prudence of OVEC's unit commitment practices, and Duke's oversight of operational and planning decisions made at the OVEC units in 2019.

Q8. HOW IS YOUR TESTIMONY STRUCTURED?

A8. In Section 2, I summarize my findings and recommendations for the PUCO. In Section 3, I provide background on the OVEC plants and the contract that governs the plants' operations.

In Section 4, I evaluate the costs paid by Duke's consumers under the Price Stabilization Rider in 2019. I discuss how Duke has paid unreasonable prices, significantly above the market value of energy and capacity in PJM to OVEC, and now seeks to pass on these excess costs to its consumers through the Price Stabilization Rider. I present several different metrics that can be used to value the services provided by OVEC.

In Section 5, I review the contemporaneous analysis that Duke conducted at the time the Price Stabilization Rider was approved. I review the cost the Company projected at the time the Price Stabilization Rider was approved versus the actual

costs that Duke collected from consumers in 2019 under its Price Stabilization Rider.

In Section 6, I review the prudence of OVEC's plant operations in 2019. I present evidence of OVEC's uneconomic operational practices that are driving the substantial losses at the units. Next, I discuss Duke's oversight of the operational and planning decisions at the OVEC units in 2019. Finally, I summarize Duke's role in managing OVEC's planning and plant operations under the OVEC Agreement, and I discuss what information Duke had on the cost to operate the plants and what steps it took to influence plant management and operations.

Q9. WHAT DOCUMENTS DID YOU USE FOR YOUR ANALYSIS, FINDINGS, AND OBSERVATIONS?

A9. My analysis relies primarily upon the following information: (1) the audit report performed in this proceeding by London Economics International, LLC ("LEI"); (2) OVEC's 2020 annual report; (3) discovery responses of Duke witnesses associated with the audit; (4) the testimony of Judah Rose filed in Case No. 17-1263-EL-SSO, where the PUCO approved Duke's collection of OVEC costs; and (5) information filed with the U.S. Bankruptcy Court when FirstEnergy Solutions attempted to cancel its obligations under the OVEC Agreement. I also rely on some public information associated with prior proceedings relating to the OVEC

plants and, to a limited extent, I rely on certain external, publicly available documents such as State of the Market reports for PJM. I also rely on my prior knowledge of the OVEC plants from other cases in which I testified regarding OVEC.[1]

II. FINDINGS AND RECOMMENDATIONS

Q10. PLEASE SUMMARIZE YOUR FINDINGS.

A10. My primary findings are:

1. When Duke obtained approval in 2018 to collect OVEC costs under the Price Stabilization Rider, Duke projected it would pay [redacted] in above-market energy and capacity costs in 2019. These are above-market costs it expected to pass on to consumers.

2. In 2019, Duke incurred $24.6 million in above-market costs for power from the OVEC plants and passed those costs on to consumers.

3. OVEC's above-market costs in 2019 were [redacted] larger than forecast by Duke's expert when the Company obtained the PUCO's approval in 2018 to collect OVEC costs under the Price Stabilization Rider.

4. OVEC uneconomically operated its two power plants, Kyger Creek and Clifty Creek, which led to lower market revenues and therefore higher net costs to operate the plants than it would have incurred if it had limited operations to periods when the plant's production costs equaled or were

[1] Michigan Cases U-20224, U-20530, U-20804.

below energy market prices. These additional costs could have been mitigated with more prudent unit commitment practices.

5. Duke imprudently managed the OVEC Agreement during 2019 and did not take sufficient steps to minimize costs and losses during that period despite its own analysis projecting that the units would incur net losses if they were operated at certain times.

6. OVEC will incur significant costs to comply with the U.S. Environmental Protection Agency's ("EPA") Coal Combustion Residuals rules ("CCR") and Effluent Limitation Guideline ("ELG") rules. Spending on these capital investments will increase OVEC demand charges and make the plants even less competitive with the market than they currently are. But to date there has been almost zero regulatory oversight of these investments by any of the state commissions where the OVEC owners are located.

Q11. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A11. Based on my findings, I offer the following chief recommendations:

1. The PUCO should disallow the $24.6 million in above-market energy and capacity prices related to the OVEC plants for 2019 and find that Duke acted imprudently by including these costs in the Price Stabilization Rider.

2. The PUCO should find that the OVEC plants were uneconomically committed, and thus incurred additional excess costs under the Price Stabilization Rider.

3. Going forward, the PUCO should require that Duke provide documentation of the daily unit commitment decisions used for the OVEC plants.

4. The PUCO should put Duke on notice that it will not permit the Company to develop its next Electric Security Plan ("ESP"), or other proceeding to

extend the Price Stabilization Rider, based on the assumption that Duke will continue purchasing power from OVEC at above market prices. Duke should conduct a transparent and comprehensive retirement study for the OVEC plants (that includes evaluation of a switch to seasonal operations at both plants) or develop a competitive bidding process demonstrating that it is prudent to continue purchasing OVEC power.

5. The PUCO should put Duke on notice that it will not permit Duke to collect costs from consumers for OVEC under the Legacy Generation Rider in the future related to the Coal Combustion Residuals rules ("CCR") or Effluent Limitation Guideline ("ELG") compliance unless Duke demonstrates in advance in a transparent and comprehensive manner that any planned investments to comply with the EPA's CCR and ELG rules are prudent and reasonable.

6. The PUCO should put Duke on notice that it will disallow collection in future cases for OVEC costs incurred as a result of imprudent unit commitment decisions.

III. DUKE PURCHASES POWER FROM OVEC UNDER THE OVEC AGREEMENT.

Q12. WHAT IS OVEC AND HOW IS IT RELATED TO DUKE'S OHIO CONSUMERS?

A12. OVEC is jointly owned by twelve utilities in Ohio, Indiana, Michigan, Kentucky, West Virginia, and Virginia. OVEC operates two 1950s-era coal-fired power plants— (1) Kyger Creek, a five-unit, 1,086 MW plant in Gallia County, Ohio, and (2) Clifty Creek, a six-unit, 1,303 MW plant, in Jefferson County, Indiana. The OVEC plants were originally built to provide power for the Piketon uranium

enrichment facility, but the facility ceased doing uranium enrichment and OVEC ceased selling power to the Department of Energy for the Piketon plant effective September 30, 2003.[2]

Today the plants provide their output to the twelve owners, one of which is Duke, under the OVEC Agreement long-term contract. The agreement was originally signed on July 10, 1953 and then amended on August 11, 2011.[3] It governs each company's rights and duties as to the power produced by the OVEC plants. OVEC bills the sponsoring companies for their shares of energy, capacity, and ancillary services under the OVEC Agreement. Each sponsoring company's power is sold into the PJM market and each company gets the resulting revenues. In Ohio, a Price Stabilization Rider was approved by the PUCO to pass through to consumers the positive or negative difference between the OVEC costs billed to Duke under the OVEC Agreement and OVEC revenues received from the PJM market.

Q13. DO YOU HAVE ANY PRIOR EXPERIENCE WITH THE OVEC PLANTS?

A13. Yes. Indiana Michigan Power, a subsidiary of American Electric Power ("AEP"), obtains power from the OVEC plants for their consumers in Indiana and

[2] Ohio Valley Electric Corporation, Annual Report – 2019 (p. 1).

[3] *Id*.

Michigan. I filed testimony before the Michigan Public Service Commission in cases where the prudency of OVEC costs was at issue (see Table 1):

Table 1: Prior testimony filed by Devi Glick related to OVEC costs

Case #	Date of Testimony	On Behalf of
U-20530	August 21, 2021	Attorney General of Michigan
U-20804	March 12, 2021	Sierra Club
U-20224	October 23, 2020	Sierra Club

Q14. BASED ON YOUR EXPERIENCE WITH OVEC IN THE CURRENT CASE AND THESE OTHER DOCKETS, ARE THESE PLANTS PROVIDING VALUE TO THE CONSUMERS OF THE TWELVE OVEC COMPANIES?

A14. No. These plants are old, inefficient, and costly to maintain and operate. They are also increasingly uncompetitive in the market, due in large part to the entry and abundance of new renewable generation and gas facilities that are coming online. As a result, OVEC's costs for energy and capacity are significantly higher than market prices for energy and capacity. These high costs are all passed on to the consumers of the twelve OVEC companies.

Q15. WHAT PORTION OF OVEC IS DUKE RESPONSIBLE FOR?

A15. Duke's share of the agreement with OVEC is 9.0 percent.[4] This means that Duke is responsible for 9.0 percent of OVEC's fixed and variable costs while also being entitled to a 9.0 percent share of OVEC's power output. According to Duke's

[4] Duke Energy Ohio Response to LEI-DR-03-005.

responses to OCC's discovery requests, this translated into an installed capacity ("ICAP") share of [redacted] MW in 2019[5] (this works out to approximately 198 MW before losses).[6]

Q16. HOW DOES DUKE COLLECT OVEC COSTS FROM CONSUMERS?

A16. My understanding is that the PUCO approved a Price Stabilization Rider to allow Duke to collect these costs.[7] Under the Price Stabilization Rider, Duke provides consumers with the net costs or net revenues associated with Duke's ownership share of the OVEC plants and its entitlement to 9 percent of OVEC's output under the OVEC Agreement. This means that if OVEC's costs exceed market revenues, in a given year, Duke's consumers pay the difference. When PUCO initially approved the Rider, then-PUCO Chairman Asim Haque stated in a concurring opinion, "This should not be perceived as a blank check, and consumers should not be treated like a trust account."[8] This authorization extended through 2024.[9]

[5] Duke Energy Ohio CONFIDENTIAL Response to OCC-INT-04-008.

[6] Direct Testimony of John Swez, page 3.

[7] Audit of the Price Stabilization Rider of Duke Energy Ohio, Final Report. Prepared for Public Utilities Commission of Ohio by London Economics International, LLC. Page 8.

[8] *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Purchase Power Agreement*, PUCO Case 14-1693-EL-RDR, Opinion and Order, Concurring Opinion of Chairman Haque at p.5 (March 31, 2016)

[9] Opinion and Order in Case No. 17-1263-EL-SSO (ESP IV).

In 2019, the Ohio legislature approved H.B. 6, which replaced the Price Stabilization Rider effective January 1, 2020 and extended Duke's approval to collect OVEC costs through 2030.[10]

Q17. DID THE BANKRUPTCY OF FIRSTENERGY SOLUTIONS ("FES") IMPACT DUKE'S OVEC ENTITLEMENT DURING THE AUDIT PERIOD?

A17. Yes, during the audit period, OVEC allocated to Duke a portion of FES' 4.85 percent share of energy and capacity based on Duke's proportional ownership of the OVEC plants. Duke paid the variable energy costs associated with this additional entitlement but was not responsible for any FES fixed costs or demand charges.[11]

Q18. HOW LONG IS DUKE UNDER CONTRACT WITH OVEC UNDER THE OVEC AGREEMENT?

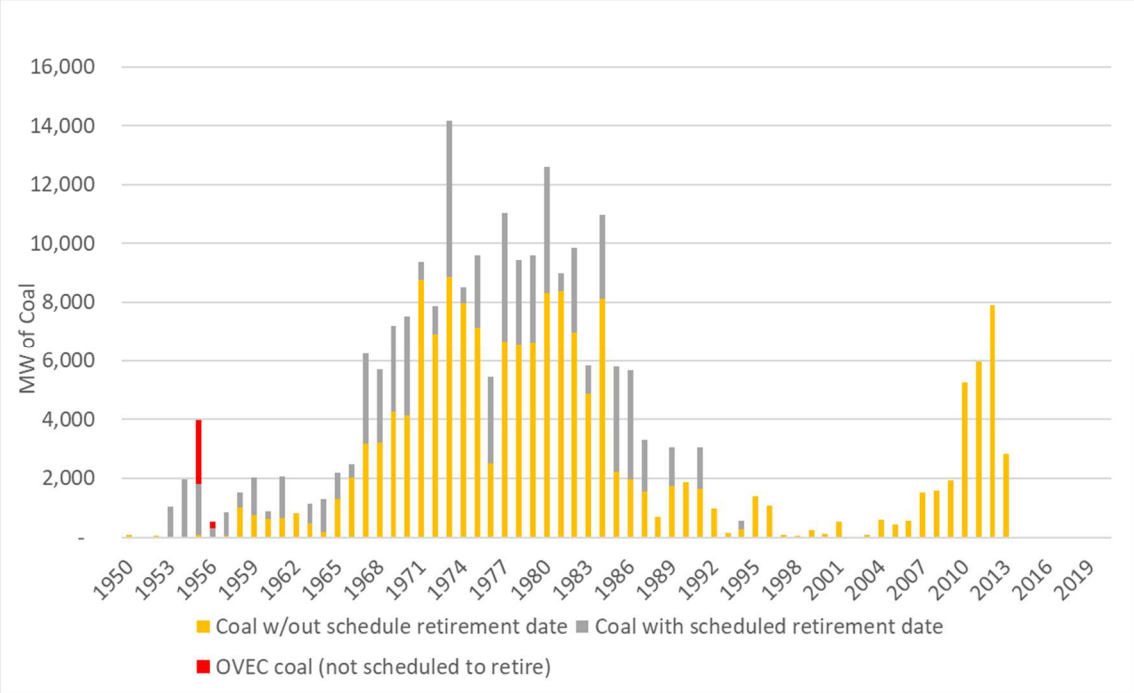
A18. The OVEC Agreement expires in 2040. The Clifty Creek and Kyger Creek Plants will each be 85 years old at this time. As shown in Figure 1, Clifty Creek and Kyger Creek are the oldest utility-owned coal fired power plants in the United States (over 20 MW in size) without a scheduled retirement date. Duke and AEP have both recently announced accelerated retirement dates for many of their coal

[10] House Bill 6, Sec. 4928.148. (A), effective October 22, 2019. Available at https://www.legislature.ohio.gov/legislation/legislationsummary?id=GA133-HB-6.

[11] Duke Energy Ohio Response to OCC-INT-02-001.

plants based on the declining economics of operating aging coal plants.[12] All of these plants are newer than the OVEC units, which have no firm retirement dates. It is very concerning that Duke plans to continue relying on high cost power from OVEC's aging power plants given the presence of lower cost alternatives of reliable power to serve its consumers.

Figure 1: Retirement status of current coal capacity by year online



[12] Darren Sweeney, S&P Global. *AEP to retire more than 1,600 MW of coal capacity.* November 2020. Available at https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/aep-to-retire-more-than-1-600-mw-of-coal-capacity-61144417; Darren Sweeny, S&P Global. *AEP to close both units at 2,600 MW Rockport coal plant by end of 2028*. September 2021. Available at https://ieefa.org/aep-to-close-both-units-at-2600mw-rockport-coal-plant-by-end-of-2028/. Darren Sweeny, Krizka Danielle, and Del Rosario, S&P Global. *Duke Energy considering retiring 9,000 MW Of coal, adding vast amounts of storage.* September 2020. Available at https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/duke-energy-considers-retiring-9-000-mw-of-coal-adding-vast-amounts-of-storage-60476894.

Source: U.S. Energy Information Administration ("EIA"), form 860, supplemented by public information on updated unit retirement dates Duke passed on to consumers unreasonable charges for OVEC power under the Price Stabilization Rider in 2019.

IV. DUKE PASSED ON TO CONSUMERS UNREASONABLE CHARGES FOR OVEC POWER UNDER THE PRICE STABILIZATION RIDER IN 2019.

A. Duke's consumers are paying unreasonable costs under the Price Stabilization Rider.

Q19. HOW DOES DUKE SERVE CONSUMER LOAD, AND WHICH ASSOCIATED COSTS ARE AT ISSUE IN THIS CASE?

A19. Duke serves consumers who choose to buy their power from Duke as the provider of last resort. Duke buys power for these consumers through a descending clock auction to obtain the lowest reasonable prices. This is known as the Standard Service Offer ("SSO") price. Under the Price Stabilization Rider, OVEC sells its output into the PJM market and the difference between OVEC's costs and the market price is flowed through to consumers as either a credit or charge Duke's share of the OVEC output is not used to supply any of Duke's consumers.

Q20. WHAT DOES IT MEAN THAT DUKE IS PAYING ABOVE-MARKET COSTS FOR OVEC'S POWER AND PASSING THOSE COSTS ON TO CONSUMERS UNDER THE PRICE STABILIZATION RIDER?

A20. OVEC's costs are substantially higher than PJM market prices for the same energy, capacity, and ancillary services. When OVEC sells its output into the PJM market, the difference between OVEC's costs and the PJM market prices are charged or credited to Duke's consumers under the Price Stabilization Rider.

Q21. DOES THE PRICE STABILIZATION RIDER PROVIDE VALUE TO DUKE CONSUMERS?

A21. No. I compared the total cost billed to members of the OVEC Agreement by adding demand and transmission charges to the energy charges I already reviewed. I compared this cost to the value of the energy, capacity, and ancillary services provided by OVEC as sold into the PJM market. OVEC Agreement billing statements show that OVEC charged Duke [redacted] for 1,062,624 MWh in 2019, for an average cost of [redacted][13] In contrast, the value of the market revenue that OVEC obtained for the energy, capacity, and ancillary services it sold into the PJM market was equivalent to only [redacted] for

[13] Calculated based on Duke responses to LEI POD 02-020 CONFIDENTIAL Attachments (Monthly Bills); and Duke Response to OCC-INT-004 CONFIDENTIAL Attach.

Duke in 2019.[14] This is well below the cost OVEC is charging Duke, and as a result, substantial costs were passed on to Duke's consumers under the Price Stabilization Rider in 2019.

This continues a pattern of exceptionally high prices paid under the OVEC Agreement (relative to the market value) over the past five years. As shown in Table 2, OVEC's average cost per MWh across all owners has regularly been substantially above the market value of its energy and capacity combined.

[14] Duke response to OCC INT 04-004 CONFIDENTIAL Attachments.

Table 2: OVEC power costs and revenues under the OVEC Agreement vs. market prices

	MWh Electricity	Total OVEC Charges billed ($Million)	OVEC ($/MWh)	Energy and capacity market value* ($/MWh)	Total above-market costs ($Million)
2015	8,681,829	$559.1	$64.40	$47.02	$150.84
2016	9,745,956	$571.7	$58.66	$38.50	$196.50
2017	11,724,662	$636.3	$54.27	$37.85	$192.47
2018	11,863,505	$644.1	$54.29	$44.28	$118.75
2019	11,234,353	$640.8	$57.04	$35.91	$237.36

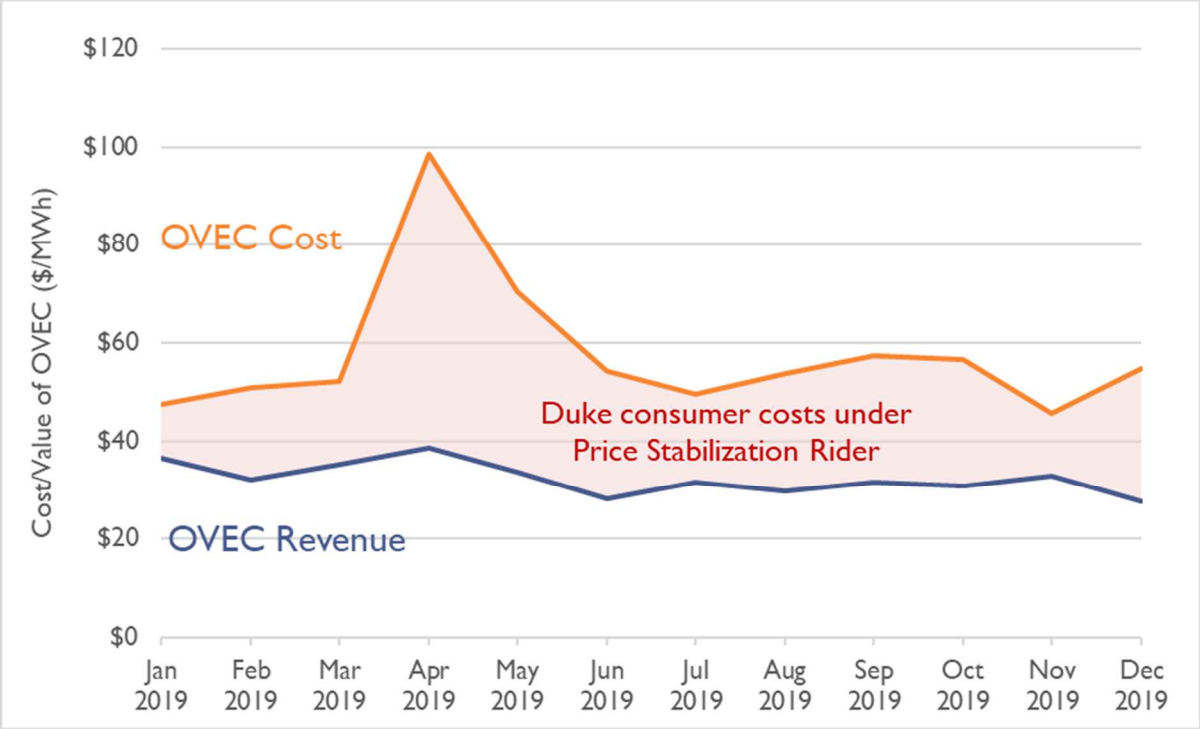
Note: The total costs for the OVEC plants in this table differ slightly from the totals implied by the excess costs we calculated for just Duke's share of the plant. We relied on Duke's own Company data for Duke's share of the plant, but we had to rely on public data to calculate the total revenues for the entire OVEC plant. Energy value is load weighted. Capacity value is based on the BRA Base Residual Auction results from each relevant year.
Source: OVEC annual report 2019, page 44; PJM locational marginal pricing from PJM data miner 2 available at https://dataminer2.pjm.com/feed/da_hrl_lmps; hourly load data downloaded from U.S. Clean Air Markets Database using EPA's *Field Audit Checklist Tool*; Capacity prices from PJM State of the Market Reports 2014-2019.

Q22. HOW MUCH IN EXCESS COSTS WERE DUKE'S CONSUMERS CHARGED UNDER THE PRICE STABILIZATION RIDER IN 2019?

A22. In 2019, Duke collected $24.6 million in excess costs under the Price Stabilization Rider while providing consumers no additional value. In **Error! Reference source not found.** below, I show the all-in monthly charges and monthly market revenues for OVEC being passed through to Duke's consumers, and the net

difference between the two that Duke consumers are paying in each month under the Price Stabilization Rider. This shows that in each month of 2019 Duke consumers were paying substantial costs under the Price Stabilization Rider.

Figure 2: All-in OVEC cost / revenue for energy, ancillary services, and capacity compared to PJM market revenue in 2019



Source: Duke Response to LEI-DR-02-020, CONFIDENTIAL Attachments (Monthly Bills); Duke Response to OCC-INT-04-004, CONFIDENTIAL Attachment.

Q23. HOW DO YOU CALCULATE THE COST TO CONSUMERS UNDER THE PRICE STABILIZATION RIDER?

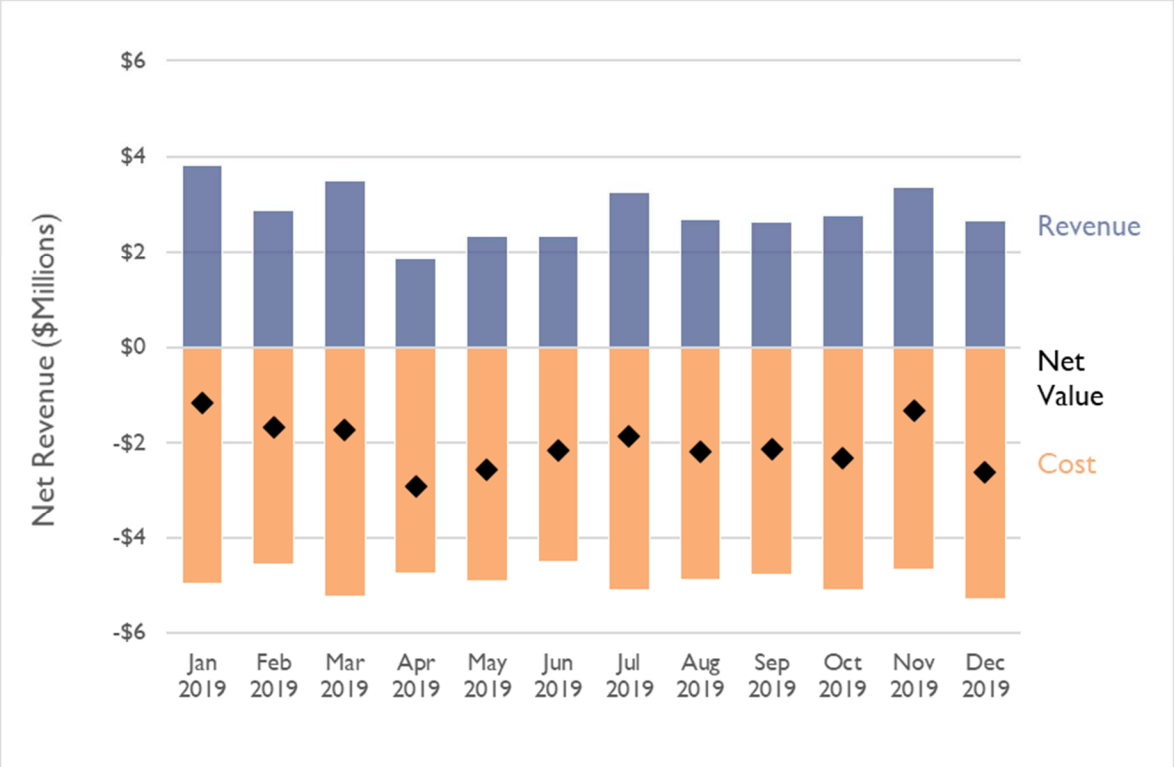
A23. Duke provided the monthly billing from OVEC for 2019 which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[15] The Company also provided revenue by month for the energy, capacity, and ancillary services that OVEC sold into the PJM market.[16]

To find the net value or cost passed on to consumers under the Price Stabilization Rider, I assumed the cost of the OVEC contract was equivalent to the monthly billing from OVEC. I assumed the value of the OVEC Agreement would be equal to the sum of the energy, ancillary services, and capacity value. Figure 3 below shows Duke's share of the monthly OVEC billing versus Duke's share of the revenue that OVEC obtained from selling the energy, ancillary services, and capacity into the PJM market for 2019. In every month, Duke was billed substantially more by OVEC than the PJM market price for equivalent levels of services, and therefore it is passing on substantial costs to consumers under the Price Stabilization Rider.

[15] Duke Response to LEI-DR-02-020, CONFIDENTIAL Attachments (Monthly Bills).

[16] Duke Response to OCC-INT-04-004, CONFIDENTIAL Attachment.

Figure 3: OVEC billing versus Duke's share of PJM revenue from energy, ancillary services, and capacity (2019)



Source: Duke Response to LEI-DR-02-020, CONFIDENTIAL Attachments (Monthly Bills); Duke Response to OCC-INT-04-004, CONFIDENTIAL Attachment.

Q24. WHAT DO YOU CONCLUDE WITH RESPECT TO THE PRICE STABILIZATION RIDER?

A24. Based on Duke's own data I find that under the Price Stabilization Rider, in 2019 alone, the total billed charges cost Duke's consumers $24.6 million more than the market price for the same amount of energy, capacity, and ancillary services.

This is consistent with the auditor's finding published in October 2020.[17] As explained in the Direct Testimony of Michael Haugh, the auditor initially opined in her report that "running the plants was not in the best interest of ratepayers."[18] However, the auditor later removed that opinion from the final report at the PUCO Staff's request.[19] I concur with the auditor's preliminary opinion contained in the draft audit report that was subsequently removed at Staff's request – running the OVEC plants is not in the best interest of Duke's consumers.

B. A reasonable price to pay for power under the Price Stabilization Rider should be measured based on the cost billed for similar services or the cost of replacement resources.

[17] Audit of the Price Stabilization Rider of Duke Energy Ohio, Final Report. London Economics International, LLC. Prepared for the Public Utilities Commission of Ohio. October 2020. Figure 8, Column H at page 26.

[18] Direct Testimony of Michael P. Haugh, Exhibit MPH-3.

[19] *Id.*

Q25. ARE THERE ANY METRICS THAT CAN BE USED TO EVALUATE THE REASONABLENESS OF DUKE'S CHARGES UNDER THE PRICE STABILIZATION RIDER?

A25. Yes. First and foremost, Duke procures electricity for consumers as the provider of last resort using a descending clock auction, as I explained earlier. This ensures that the price that Duke charges consumers through the SSO reflects the lowest reasonable cost for power. The Price Stabilization Rider is not associated with any additional power supply, but instead charges or credits consumers based on how much above or below market prices Duke paid to OVEC. The difference between the SSO price and the additional charges under the Price Stabilization Rider in 2019 show that the Price Stabilization Rider charges are unreasonable.

In addition to the SSO price obtained through the descending clock auction, there are several long-term supply comparisons we can use to evaluate whether the costs charged under the Price Stabilization Rider in 2019 are reasonable. These include: (1) The costs billed or paid by other entities for similar services provided under long-term power purchase agreements ("PPA"); (2) the cost of replacement capacity resources as represented by Cost of New Entry ("CONE"); (3) The cost of replacement capacity and energy resources as represented by responses to requests for proposals (RFP) and other Company information; (4) and the PJM short-term capacity and energy market.

Table 3 below summarizes the alternative benchmarks discussed in this section on a $/MWh basis and calculates the total excess costs incurred under the Price Stabilization Rider in 2019 relative to each benchmark.

Table 3: OVEC cost benchmarks

	$/MWh	**Excess costs incurred ($ Million)** *Excess cost = Quantity (MWh) x (OVEC $/MWh cost – alternative benchmark $/MWh cost)*
OVEC cost[1]	$57.04	NA
Cost of similar services		
MPPA billing from Consumers Energy for Campbell Unit 3 in 2020[2]	$28.87	$28.1
Consumers PPA expense for MVC in 2020[3]	$48.89	$6.8
Value of CONE & PJM Base Residual Auction		
CONE – combined cycle plant[4]	$48.56	$7.1
CONE – combustion turbine[4]	$46.40	$9.4
PJM Base Residual Auction [5]	$32.14	$24.6
Replacement resource PPA prices		
I&M renewable RFP results (average)[6]		
Medium solar	$50.00	$5.6
Large solar	$44.00	$12.0
Wind	$45.00	$10.9
NIPSCO RFP Results[7]		
Solar PV	$39.30	$17.0
Solar PV + battery storage	$43.30	$12.7
Wind	$37.10	$19.3

Sources: [1]OVEC 2019 Annual Report; [2] Consumers billing statements to MPPA for JH Campbell Unit 3 Power in 2020; Consumers Response to MEC Request 1.9 in Case No. U-21090; [3]DTE billing statements to MPPA for Bell River Power in 2020; DTE Response to MEC Request 4.1 in Case No. U-20528; [4] Exhibit A-17 (JLR-1) in Case No U-20526; [5] PJM, Default MOPR Floor Offer Prices for New Generation Capacity Resources. March 11, 2020; [6] State of the Market Report for PJM, 2018. Page 288. State of the Market Report for PJM, 2019. Page 287; [7] Indiana Michigan Power: 2021 Integrated Resource Plan, Public Stakeholder

Meeting #3A, July 27, 2021; [8] NIPSCO's 2019 Request for Proposals Results, February 18, 2020.

Q26. HOW DOES THE COST OF POWER UNDER THE PRICE STABILIZATION RIDER IN 2019 COMPARE TO THE BILLED COSTS FOR SIMILAR PPAS?

A26. The cost of power under the Price Stabilization Rider in 2019 is much higher than the cost paid for power under several similar PPAs in the region. I reviewed Michigan Public Power Agency ("MPPA") billing statements from Consumers for J.H. Campbell 3[20] and calculated the average cost billed for power charged for this unit. J.H. Campbell 3 is a 1,420 MW multi-unit coal-fired generating plant located in Western Michigan and owned by CMS Energy, the parent company of Consumers Energy. I find that in 2020, Consumers Energy billed MPPA an average of $28.87/MWh for power purchased from J.H. Campbell 3.[21] These charges covered the construction, fuel, and operations and maintenance ("O&M") expenses from similar thermal resources and provided both energy and capacity to MPPA.

[20] Consumers billing statements to MPPA for JH Campbell Unit 3 Power in 2020 obtained under FOIA. Calculations based on expenses before adjustments. Generation from Ex AG-11, Consumers Response to MEC Request 1.9, Docket No. U21090.

[21] The billing data provided by Consumers was different than the cost data provided in the individual monthly bills sent by Consumers to MPPA. The average cost of $29.03/MWh in 2020.

I also reviewed Consumers' purchased power costs and found that for 2020 Consumers paid $48.89/MWh for power from Michigan Cogeneration Venture ("MCV").[22] MCV is a natural gas-fired electrical and steam co-generation plant located in Midland, Michigan.

Q27. WHAT IS COST OF NEW ENTRY ("CONE") AND HOW DOES THE VALUE OF CONE COMPARE TO THE COST PAID UNDER THE OVEC AGREEMENT?

A27. CONE is a conservative measure of value that represents the cost of building new gas-fired generation capacity. If Duke were capacity constrained, the capacity-related portion of the Price Stabilization Rider costs could be valued at PJM's CONE. The PJM value of CONE for a new combined cycle unit is $320/MW-Day and for a new combustion turbine unit it is $294/MW-Day.[23] This works out to a total value of $48.11/MWh and $46.40/MWh when the capacity-related portion of the Price Stabilization Rider costs is valued based on CONE of a new combined cycle unit and combustion turbine respectively.

[22] Exhibit A-17 (JLR-1), Case No U-20526.

[23] Default MOPR Floor Offer Prices for New Generation Capacity Resources. March 11, 2020. Accessed at https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200311/20200311-item-06c-default-mopr-cone.ashx.

I arrived at these values by multiplying the $/MW-Day CONE values by the [redacted] MW of capacity that Duke receives and then multiplying that by 365 days in a year. I then added the energy and ancillary revenues associated with Duke's share of OVEC from the PJM market to find the total value of the power produced by OVEC. Finally, I divided that total value of the power by Duke's share of the MWh of generation produced by the OVEC plants to find the total $/MWh.

Q28. FOR CONTEXT, HOW DOES THE VALUE OF CONE COMPARE TO THE CAPACITY PRICE FROM PJM'S MOST RECENT CAPACITY AUCTION?

A28. CONE is much higher than the cleared capacity value (auction price) from PJM's most recent 2022/2023 Base Residual Auction because there remains surplus capacity available for participation in the PJM capacity market. This auction produced a capacity price of only $50/MW-Day for years 2022–2023, which is the lowest it has been in the past five auctions.

Q29. DO YOU EXPECT THIS EFFECTIVE RESET OF PJM CAPACITY PRICE TRENDS TO CONTINUE?

A29. Yes, Capacity prices are expected to continue to drop moving forward, based on downward pressure from three main sources: (1) lower demand, as loads continue to drop below what utilities project due in large part to increasing levels of energy

efficiency investment and adoption of behind the meter solar PV;[24] (2) increased supply from the massive quantities of solar and wind (and even gas resources) in the PJM interconnection queue, many of which are coming online in the coming years;[25] and (3) relaxation of the MOPR, which more fully allows for capacity credit of new renewables and other subsidized generation to show up in the PJM capacity auctions. These factors have combined to reduce PJM prices from inordinately high historical levels down to what was seen in the 2022/2023 base residual auction clearing prices in April of 2021 and will continue to reduce prices in future PJM auctions.

Q30. WHAT IS THE RELEVANT CONCLUSION YOU DRAW FROM THESE FACTS?

A30. In future years, the amount by which OVEC's costs exceed PJM market prices is expected to increase.

[24] PJM, 2023/2024 RPM Base Residual Auction Planning Period Parameters. Accessed at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-planning-period-parameters-for-base-residual-auction-pdf.ashx.

[25] PJM, Interconnection Process Reform Task Force Update, May 11, 2021. Accessed at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210511/20210511-item-11-interconnection-process-reform-task-force-update.ashx.

Q31. WHAT ARE YOUR CONCLUSIONS REGARDING THESE METRICS FOR EVALUATING THE VALUE OF CAPACITY AND ENERGY PROVIDED?

A31. The costs that Duke collected from consumers under the Price Stabilization Rider in 2019 are extremely high by any reasonable measure. I have presented a number of reasonable alternatives in this section, for both current fossil resources contracted under similar PPAs, new fossil resources, and new renewable resource bid prices that demonstrate this point. Yet Duke consumers are paying as much as $24.6 million per year in excess of the cost of PJM market prices for energy and capacity. They are also well above the other long-term supply comparisons I described. These other resources discussed above, or similar resources, could have been used as a hedge against the SSO price under the Price Stabilization Rider. These other resources could have been obtained at much lower cost than the OVEC plants. I found no evidence that Duke did any competitive bidding process before selecting the OVEC plants as a price hedge for the SSO price. That was imprudent, and the PUCO should disallow the $24.6 million in above-market costs.

V. DUKE'S OWN CONTEMPORANEOUS ANALYSIS CONDUCTED IN 2018 INDICATED THAT THE COMPANY WOULD PAY SUBSTANTIALLY ABOVE MARKET FOR OVEC POWER UNDER THE PRICE STABILIZATION RIDER.

Q32. WHAT COSTS RELATED TO THE OVEC PLANTS DID DUKE COLLECT FROM CONSUMERS UNDER THE PRICE STABILIZATION RIDER IN 2019?

A32. Duke included $24.6 million in costs under the Price Stabilization Rider.[26] This is the amount by which the OVEC costs for energy and capacity production exceeded the PJM market price for energy and capacity. This matches the findings the auditor discusses at page 25 of the Audit Report.[27]

[26] Audit of the Price Stabilization Rider of Duke Energy Ohio, Final Report. London Economics International, LLC. Prepared for the Public Utilities Commission of Ohio. October 2020. Figure 8, Column H at page 26.

[27] Audit of the Price Stabilization Rider of Duke Energy Ohio Final Report. London Economics International LLC prepared for the Public Utilities Commission of Ohio. October 15, 2020.

Q33. DID DUKE CONDUCT ANY ANALYSIS TO SUPPORT ITS DECISION TO COLLECT OVEC COSTS IN ITS PRICE STABILIZATION RIDER?

A33. Yes. Duke used the analysis conducted by Judah Rose of ICF International, Inc. to support of its decision to include OVEC power costs in the Power Cost Stabilization Rider in its ESP IV.[28] Duke filed testimony on July 10, 2018.

Q34. WHY SHOULD THE PUCO CONSIDER DUKE'S 2018 ANALYSIS IN REVIEWING THE REASONABLENESS OF DUKE'S PRICE STABILIZATION RIDER COSTS THAT IT ACTUALLY COLLECTED IN 2019?

A34. Duke's testimony in the 2018 case is important to review because, in approving the Price Stabilization Rider, the PUCO relied on the forecasts about OVEC costs and PJM energy and capacity prices from 2018 through 2025 presented by Mr. Judah Rose. We now have actual OVEC cost data and PJM market price data for 2019 and can compare Mr. Rose's projections of net margins to the costs and revenues that actually materialized.

[28] Direct Testimony of Judah Rose, Case No. 17-1263-EL-SSO (ESP IV) (July 10, 2018).

Q35. DESCRIBE THE ANALYSIS CONDUCTED BY MR. ROSE AND THE FINDINGS THAT RESULTED.

A35. Mr. Rose created a forecast of the future costs of power from the OVEC plants over the time period 2018–2025 and compared those costs to a forecast of future market prices in PJM. He assessed the values based on variable costs only, and then calculated the full cost that Duke seeks to pass on to its consumers.

Q36. DO YOU HAVE ANY CONCERNS WITH THE CONCLUSIONS THAT MR. ROSE PRESENTED IN HIS TESTIMONY?

A36. Yes. He states that the units have "operating leverage" (i.e., their revenues are projected to increase faster than their costs).[29] He also concludes that the contract has hedge value because it has lower volatility than relying on the market.[30] And his top line finding is that continued plant operation through 2025 is economic, and therefore that the plants should continue to operate.[31] But these statements all contradict the results of his analysis, which shows that OVEC's costs are projected to exceed forecasted market revenue.

[29] *Id,* page16.

[30] *Id.*

[31] *Id*, page 22.

Q37. DID MR. ROSE'S 2018 ANALYSIS SUPPORT THE CONCLUSION THAT DUKE'S COSTS UNDER THE PRICE STABILIZATION RIDER IN 2019 ARE REASONABLE AND PRUDENT?

A37. No. Mr. Rose's analysis showed that OVEC's projected energy and demand charges will exceed forecasted market revenues by $77 million on a net present value basis over the analysis period (2018–2025).[32] For 2019, his analysis showed that the OVEC's projected energy and demand costs would exceed the PJM market revenues that Duke received from that same power by [redacted].[33] This means that regardless of which yearly sub-set of costs are compared, the plants operating costs exceeded the market revenues they can obtain for their energy and capacity deliveries.

Q38. DO YOU HAVE ANY OTHER CONCERNS WITH DUKE'S RELIANCE ON MR. ROSE'S ANALYSIS?

A38. Yes, in April 2018, only a few months before submitting the above-referenced testimony for Duke, Mr. Rose submitted an affidavit on behalf of the Debtors as part of FES Bankruptcy proceeding[34] (attached as DG-2 to my testimony). The purpose of his affidavit was to support FES' claim that it should be allowed to

[32] *Id.*, Exhibit 2.

[33] *Id.,* CONFIDENTIAL Exhibit 39.

[34] Expert Declaration of Judah L. Rose, Chapter 11, Case No. 18-50757. Filed April 1, 2018.

cancel its rights and obligations under the OVEC Agreement contract because it was projected to lose a substantial amount of money under the contract. As part of this affidavit, Mr. Rose evaluated the cost of maintaining the OVEC Agreement with OVEC.[35] The full results were presented in the Declaration of FES executive Kevin Warvell (attached as DG-3 to my testimony).

Rose projected FES would lose $268 million under the OVEC contract on an undiscounted basis over the life of the contract through 2040.[36] The OVEC costs are the same on a unit basis across all owners, so the $268 million loss for FES' 4.85 percent share of OVEC can be scaled up to find the collective projected costs for all owners, which works out to $5.5 billion. For Duke's 9 percent share, that works out to $497 million in loss through 2040. In other words, Duke's consumers were projected to pay $497 million in above-market costs for energy and capacity over the remaining life of the contract for Duke's share of the contract.

These findings, published only three months prior to Duke's testimony in Case No. 17-1263-EL-SSO, demonstrate that the OVEC plants were projected to be

[35] Expert Declaration of Judah L. Rose. Chapter 11, Case No. 18-50757. Filed April 1, 2018.

[36] Expert Declaration of Kevin T Warvell, page 8. Chapter 11, Case No. 18-50757. Filed April 1, 2018.

uneconomic over both the near and long-terms. It is concerning that there is such a large disparity in Mr. Rose's findings only a few months apart.

Q39. WHY SHOULD THE PUCO CONSIDER THE OVEC ANALYSIS THAT MR. ROSE PROVIDED TO THE U.S. BANKRUPTCY COURT IN 2018 IN THIS PRESENT PROCEEDING?

A39. This analysis was performed by the same witness that Duke used to obtain the PUCO's approval for the Price Stabilization Rider. It was also completed only a few months earlier, yet the findings are completely inconsistent. Mr. Rose's analysis for the PUCO projected between a $15 million gain and a $77 million loss on a net present value basis under the OVEC contracts for Duke's 9 percent share through 2025 and concluded that the plants should continue to operate.[37] Mr. Rose's analysis for the U.S. Bankruptcy Court projects $497 million in undiscounted losses under the OVEC contract for Duke's 9 percent share through 2040.

[37] Direct Testimony of Judah L. Rose, page 22. Case No. 17-1263-EL-SSO (ESP IV).

Q40. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS REGARDING MR. ROSE'S ANALYSIS ON THE OVEC PLANTS?

A40. First, the actual above-market costs that Duke passed on to its consumers under the Price Stabilization Rider in 2019 were much higher than Mr. Rose forecasted in 2018. Second, around the same time that Mr. Rose submitted testimony for Duke, Mr. Rose submitted a contemporaneous analysis for the U.S. Bankruptcy Court showing that the above-market costs for the OVEC plants would be much higher than the projections in his testimony for Duke filed at the PUCO.

VI. DUKE IMPRUDENTLY MANAGED ITS OVEC AGREEMENT BY FAILING TO TAKE ACTION TO INFLUENCE OPERATIONAL AND PLANNING DECISIONS MADE AT THE CLIFTY CREEK AND KYGER CREEK PLANTS

Q41. HOW ARE THE OVEC UNITS OPERATED AND MANAGED?

A41. According to the Amended and Restated OVEC Agreement that was in effect in 2019,[38] management of the OVEC units is governed by the 15-person Board of Directors, and operational decisions are delegated to the Operating Committee. Specifically:

[38] The OVEC Agreement was subsequently updated in October 7, 2019 and effective November 15, 2019.

> Decisions with respect to OVEC's operations are made by OVEC's management, with oversight and approval of annual capital expense budgets by OVEC's Board of Directors…Certain decisions, including those regarding procedures for scheduling delivery of available energy, and recommendations as to scheduling, operating, testing and maintenance procedures and other related matters, are delegated to the 'Operating Committee'…the unanimous approval of the Operating Committee (excluding OVEC's representative) is required to change the commitment status of 'Must Run' with respect to the offer of the 'PJM Sponsors' aggregate share of reserved Available Energy into PJM's Day-Ahead Energy Market.[39]

A. OVEC operates its two power plants, Clifty Creek and Kyger Creek, uneconomically and incurs additional losses relative to market energy prices.

[39] Duke Response to OCC-INT 04-010.

Q42. HOW OFTEN DID OVEC OPERATE ITS PLANTS IN 2019?

A42. OVEC operated the Clifty Creek and Kyger Creek plants at 50 percent and 58 percent capacity factors,[40] respectively, during 2019 despite both units incurring substantial revenue losses relative to the market. In fact, during 2019, at least one unit was online at the Clifty Creek and Kyger Creek plants during 100 percent and 96 percent of the time respectively.[41] This shows that OVEC is not taking action to limit incurring negative energy margins at its plants, and instead is operating its plants even when it projects that doing so will incur negative margins.

Q43. IS THERE EVIDENCE THAT OVEC OPERATED ITS PLANTS UNECONOMICALLY DURING MANY HOURS OF THE YEAR IN 2019?

A43. Yes. During 2019, OVEC's variable costs exceeded market locational marginal prices over half the time the units were online. As discussed above, this contributed to a total of $24.6 million in above-market costs across the two plants for Duke's consumers.[42] Coal plants such as Clifty Creek and Kyger Creek require high capital costs to stay online, and therefore they need large positive

[40] U.S. Energy Information Administration (EIA), form 923 available at https://www.eia.gov/electricity/data/eia923/ and form 860 available at https://www.eia.gov/electricity/data/eia860/.

[41] U.S. EPA Clean Air Markets, Air Markets Program Data for Clifty Creek and Kyger Creek available at: https://ampd.epa.gov/ampd/; PJM LMPs for OVEC Zone accessed at https://dataminer2.pjm.com/feed/da_hrl_lmps.

[42] *Id.*

energy margins (or sufficient capacity payments) to cover these fixed costs. When a plant loses money on a variable operating basis, that means that not only is it not covering its fuel and variable O&M costs, it is also carrying no net revenues to offset significant fixed O&M and capital costs.

Q44. HOW DID THE OVEC UNITS INCUR SIGNIFICANT LOSSES IF THEY WERE OPERATING WITHIN THE PJM MARKET?

A44. Generators operating within the PJM market generally commit their available units as either economic or must-run. For units committed economically, the market operator, PJM, has the responsibility for unit commitment and dispatch decisions. Those decisions prioritize reliability for the system as a whole, but then select plants to commit and dispatch based on short-term economics to ensure consumers are served by the lowest-cost resources available to the system. A plant committed as "economic" will operate only if it is the least-cost option available to the market (i.e., has a lower average commitment period cost than other resources available at the time).

While economic commitment and dispatch tends to be the norm for dispatchable power plants, for units such as OVEC's coal-fired power plants with long start-up and shut-down times, utilities often instead elect to maintain control of unit commitment decisions and utilize a must-run commitment status. For these units,

the utility determines independently when to commit a unit. A unit designated as must-run will operate with a power output no less than its minimum operating level.[43] The unit receives market revenue (and incurs variable operational costs) but does not set the market price of energy. If the market price of energy falls below its operational cost, a must-run unit will not turn off and can incur losses that a utility often seeks to collect from consumers.

Because units operated by the market follow short-term economic signals, they tend to cycle off when market prices are low and therefore do not generally incur significant operational losses. The OVEC units, on the other hand, stayed online for the vast majority of 2019 despite incurring significant net revenue losses. This is because the plants were self-committed with a must-run status whenever they were available,[44] without regard for the impact on Duke's consumers' interests. OVEC used no daily analysis to drive its unit commitment decisions during 2019, as discussed below.

[43] Minimum operating level is an output threshold often determined operationally, and below which a generator is either less stable or operates inefficiently. Once the unit commitment decision is made, the level of generation output (above the minimum) is generally left to the market. The operating level is based upon the marginal running cost assumptions provided by the owner in the form of offers or bids to PJM.

[44] Duke Response to OCC-RFA-03-002.

Q45. WHAT COULD DRIVE A POWER PLANT OPERATOR SUCH AS OVEC TO UNECONOMICALLY SELF-COMMIT ITS UNITS?

A45. There are many factors that could drive a power plant operator to uneconomically self-commit their units, but four main ones are: (1) a failure to evaluate the economics of daily unit commitment decisions; (2) failure to follow the results of daily unit commitment analysis; (3) incomplete accounting of variable unit costs in unit dispatch bids; and (4) minimum take provisions in fuel contracts that "lock in" costs that would otherwise be variable.

In the case of OVEC in 2019, it is clear that the Company did not evaluate the economics of operating the plants on a daily basis (as will be discussed in the next section).

B. Duke failed to take action to influence and improve operational decisions at the OVEC plants in 2019.

Q46. WHAT IS DUKE'S ROLE IN OPERATING THE OVEC UNITS?

A46. Duke is a Sponsoring Company of OVEC, and as such Duke has one member on the Board of Directors and is allowed to appoint one member to OVEC's

Operating Committee.[45] Duke can make requests and recommendations to the Operating Committee to change unit operations but claims that it needs "unanimous approval of the Operating Committee" to change the commitment status of the OVEC units.[46]

Q47. DID OVEC USE ANY DAILY ANALYSIS UNIT COMMITMENT PROCESS OR ANALYSIS TO INFORM OPERATIONS OF ITS PLANTS IN 2019?

A47. No. In 2019, OVEC did not conduct analysis on a daily basis to inform its unit commitment process. The decision to move to a daily analysis system was not made until 2020.[47] Instead, during 2019, the available OVEC plants (except Clifty Creek Unit 6 during summer ozone non-attainment periods) were committed into the PJM day-ahead market with a "Must-Run" status at all times, except when units were unavailable due to scheduled maintenance or forced outages.[48]

[45] Duke Response to LEI-DR-06-001, CONFIDENTIAL Attachment, Section 9.05.

[46] Duke Response to OCC-INT-04-010.

[47] Duke Response to OCC-RFA-03-006.

[48] Duke Response to OCC-RFA-03-002.

Q48. DID DUKE CONDUCT A DAILY ANALYSIS TO MONITOR AND PROJECT ENERGY MARKET REVENUES FROM OPERATION OF THE OVEC UNITS?

A48. Yes, during the audit period, Duke prepared a "daily profit and loss forecast report that shows a 21-day forecast of OVEC unit participation in the PJM Day-Ahead Energy Market."[49] Duke admitted that there were days during 2019 when its analysis showed that market revenues were projected to be less than variable operating costs for the OVEC units.[50] But the Company went on to defend operation of the units during these times, stating that there may have been other reasons for a unit being online.[51]

Q49. DID DUKE PROVIDE SPECIFIC EXAMPLES OF WHAT THESE OTHER REASONS MIGHT BE?

A49. No. Duke provided no specific details or examples to support this claim.

[49] Duke Response to OCC-RFA-03-012; Duke Response to OCC-RFA-03-013.

[50] Duke Response to OCC-RFA-03-007.

[51] Duke Response to OCC-RFA-03-007; Duke Response to OCC-RFA-03-013.

Q50. DID DUKE PROVIDE THE RESULTS OF ITS DAILY ANALYSIS TO OVEC AT ANY POINT DURING 2019?

A50. No, Duke stated that during the audit period, it did not provide OVEC with its internal daily profit and loss forecast reports. The Company claims that did not provide the forecasts because the plants were not forecasted to "consistently lose money over the commitment period." Duke went on to say that it would have contacted OVEC and "may" have shared these reports if the plants had been projected to consistently lose money over the commitment period.[52]

Q51. WERE YOU ABLE TO REVIEW DUKE'S DAILY PROFIT AND LOSS SHEETS TO DETERMINE WHETHER THERE WERE ANY PERIODS OF TIME WHEN DUKE PROJECTED CONSISTENT LOSSES, YET OVEC OPERATED THE PLANTS ANYWAYS?

A51. Yes, I reviewed the 325 profit and loss forecast sheets that Duke created in 2019 and determined that there were periods of time where the plants were projected to experience consistent losses; yet Duke let OVEC operate them without sharing its projections.[53] I identified a total of [redacted] at the Clifty Creek and Kyger Creek plants where OVEC operated the plants, despite Duke's Profit and Loss analysis indicating that the plants would lose money if the plants stayed

[52] Duke Response to OCC-RFA-03-014.

[53] Duke Response to OCC-POD-03-001 CONF Attachment 1 – OCC-POD-03-001 CONF Attachment 325.

online. Thirteen of these events occurred at Clifty Creek and the other seven occurred at Kyger Creek. Based on hourly plant operations data, we know that the plants were indeed operated during each of these times, despite Duke's projections that doing so would incur losses.

Additionally, Duke's own witness presents evidence that the OVEC plants had negative energy margins during five of the twelve calendar months in 2019.[54] These costs were avoidable if OVEC had shut the plants down entirely during these months.

Q52. DID DUKE CONTACT OVEC TO REQUEST A CHANGE IN THE OFFER FOR ANY OF THE OVEC UNITS DURING THE AUDIT PERIOD?

A52. No. Duke also did not contact OVEC and request a change in its Day-Ahead scheduling decisions or practices during the audit period.[55] But once again, Duke asserted that "had the units been projected to have a negative margin for a significant amount of time and where it would have made economic sense or was possible, Duke Energy Ohio would have contacted OVEC and requested an offer change..."[56]

[54] Direct Testimony of John Swez, Page 15.

[55] Duke Response to OCC-INT-04-014.

[56] Duke Response to OCC-RFA-03-003.

Q53. HAVE OVEC'S UNIT COMMITMENT PRACTICES CHANGED IN THE YEAR AND A HALF SINCE THE AUDIT PERIOD ENDED?

A53. Yes. In the Spring of 2020, OVEC received approval from the full Operating Committee to begin offering some of its units with a commitment status of "Economic." This was done at the suggestion of Duke.[57]

Q54. IS THERE EVIDENCE THAT DUKE KNEW DURING THE AUDIT PERIOD THAT OVEC'S UNIT COMMITMENT PROCESS WAS INSUFFICIENT?

A54. Yes. In discovery, Duke provided the following response:

> Duke Energy Ohio admits that a discussion occurred among sponsors and OVEC personnel in an operating committee annual meeting in either 2018 or 2019 about potentially including the units' expected profit and loss as one of the many factors to consider in determining the commitment status of the OVEC units…However, since the OVEC units were just entering PJM as full member on 12-1-2018, there was no urgency since the current process was working and the units were forecasted as in the money.[58]

[57] Duke Response to OCC-RFA-03-006.

[58] Duke Response to OCC-RFA-03-005.

Q55. WHAT ARE STANDARD INDUSTRY PRACTICES UNDERTAKEN BY REGULATED UTILITIES TO ENSURE PLANTS THAT THEY CO-OWN ARE PRUDENTLY OPERATED?

A55. Prudent utility management practices dictate a utility would do the following in managing the operation of a plant that it co-owns to manage the costs passed on to its consumers:

1. Exercise oversight and have knowledge of the operational decisions that impact the costs passed on to its consumers.
2. Evaluate and undertake measures to reduce operational costs at the units that are operating at a loss relative to alternatives or the market.

During the review period, Duke had knowledge of the operational decisions at the units, but the Company failed to act on that knowledge to exercise oversight over unit operations, as prudent utility management practices would dictate.

Q56. WHAT DO YOU CONCLUDE REGARDING DUKE'S MANAGEMENT OF THE OVEC AGREEMENT?

A56. Although Duke had detailed daily analysis on the cost to operate the OVEC plants, and the authority under the OVEC Agreement to at least influence some of the operational decisions at OVEC, the Company declined to invoke that authority during 2019. Instead, Duke allowed OVEC to operate its power plants with a must-run status whenever the plants were available, regardless of

economics. Duke took no documented effort to reduce costs through exercise of its ownership stake in OVEC, and then passed the excess costs on to its consumers.

C. Duke did not take sufficient steps to manage costs incurred under the OVEC Agreement.

Q57. DID DUKE UNDERTAKE ANY STEPS TO LIMIT COSTS INCURRED FOR CONSUMERS UNDER THE OVEC AGREEMENT AND PASSED ONTO CONSUMERS UNDER THE PRICE STABILIZATION RIDER?

A57. No. I find that, despite (1) Duke's own projections showing that substantial costs would be passed on to consumers under the Price Stabilization Ride, and (2) Duke having clear, documented evidence that OVEC's unit commitment process was insufficient, Duke did not take appropriate steps to manage costs incurred at the OVEC units and passed on to consumers through the Price Stabilization Rider. Specifically, Duke did not attempt to limit the uneconomic commitment practices that are driving the high variable costs at OVEC, as discussed in the prior section. Duke also did not take planning steps in 2019 to limit costs passed on to consumers through the Price Stabilization Rider by either: (1) attempting to

renegotiate or terminate the OVEC Agreement,[59] (2) conducting a retirement analysis that evaluated the going-forward cost to Duke's consumers of the OVEC Agreement; (3) evaluating the cost of the option of early termination of the OVEC Agreement;[60] (4) evaluating the economics of operational changes at the OVEC plants, including seasonal operation and lower each unit's minimum operating level.

There is also no evidence that the Company re-evaluated the prudency of using the OVEC units as a hedge on the SSO price, or that the Company solicited any competitive bids for a PPA to provide an alternative hedge service.

Finally, the Company also did not conduct any analysis on the cost of complying with the EPA's Coal Combustion Residuals and Effluent Limitation Guideline rules.

[59] Duke Response to OCC-INT-04-001.

[60] Duke Response to OCC-INT-04-002; Duke Response to POD-04-001.

Q58. IS THERE EVIDENCE THAT A RETIREMENT STUDY COULD HELP THE COMMISSION IN EVALUATING THE PRUDENCE OF CONTINUED INVESTMENT IN THE OVEC PLANTS?

A58. Yes. Duke Energy conducted a retirement study as part of its most recent integrated resource plan filed with the South Carolina Public Service Commission on August 27, 2021, and this resulted in the acceleration of the retirement dates for its South Carolina coal plants by ten years or more.[61] If Duke was required to do the same for the OVEC plants, the PUCO would have more information about the projected savings consumers would see from an early retirement of the OVEC plants.

Q59. IS THERE EVIDENCE THAT SEASONAL OPERATIONS CAN BE DEPLOYED AT COAL PLANTS TO LOWER CONSUMER COSTS?

A59. Yes, this practice has been utilized by utilities around the country to shut down coal plants during the shoulder season when electricity demand is lower and market prices are lower.[62] For example, Xcel Energy in Minnesota switched two

[61] Scott Van Voorhis, Utility Dive. *Duke explores shutting coal-fired plants by 2030 in South Carolina*. September 1, 2021. Available at https://www.utilitydive.com/news/duke-explores-shutting-coal-fired-plants-by-2030-in-south-carolina-plans/605893/.

[62] Mark Morey, Alex Gorski. *EIA. As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation.* Available at https://www.eia.gov/todayinenergy/detail.php?id=44976.

coal plants to seasonal operation in 2020,[63] and Tucson Electric Power announced that it will switch one unit to seasonal operations in 2023.[64]

Q60. EXPLAIN YOUR CONCERNS WITH OVEC'S APPROACH TO ENVIRONMENTAL COMPLIANCE?

A60. I expect that OVEC will incur substantial costs to comply with the Effluent Limitation Guideline ("ELG") and Coal Combustion Residuals ("CCR") rules if the plants are allowed to operate beyond 2028. This will increase OVEC's demand charges for all owners. Commissions across the country have been conducting oversight of the prudence of utility compliance with the ELG and CCR rules. In Virginia[65] and Kentucky,[66] for example, commissions recently rejected AEP's request for approval to collect costs to comply with the ELG rules for three separate plants, all of which are newer than the OVEC plants. The auditor discusses the status of OVEC's compliance with various environmental

[63] Catherine Morehouse. *Minnesota approves Xcel request to operate 2 coal plants seasonally.* July 16, 2020. Available at https://www.utilitydive.com/news/minnesota-approves-xcel-request-to-operate-2-coal-plants-seasonally/581729/.

[64] Jeff St. John. *2 more western utilties move to close coal plants early, shirting to renewables and storage.* June 29, 2020. Available at https://www.greentechmedia.com/articles/read/two-more-western-utilities-move-to-close-coal-plants-early-shift-to-renewables-and-storage?utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+greentechmedia%2Fnews+%28Greentech+Media%3A+News%29.

[65] Order Granting Rate Adjustment Clause, August 2021. Virginia Division of Public Utility Regulation. Case No. PUR-2020-00258.

[66] Order, July 2021. Kentucky Public Service Commission Case No. 2021-000004.

laws and regulations on pages 77-89 of the audit. But to date, no Commission has required a review the prudence of compliance with the ELG and CCR rules for any of the owners of the OVEC plants.

VII. RECOMMENDATIONS

Q61. DO YOU HAVE ANY RECOMMENDATIONS REGARDING OVEC'S ENVIRONMENTAL COMPLIANCE PRACTICES?

A61. Yes. The PUCO should put Duke on notice that it will not permit Duke to collect CCR-related or ELG-related costs for OVEC from consumers under the Legacy Generation Rider in the future unless Duke demonstrates in advance that any planned investments to comply with the. EPA's CCR and ELG rules are prudent and reasonable.

Q62. DO YOU HAVE ANY RECOMMENDATION REGARDING STUDIES OR ANALYSIS THAT DUKE SHOULD CONDUCT ON THE OVEC PLANTS?

A62. Yes. The PUCO should require Duke to conduct or obtain a retirement study for the OVEC plants and file the results with the PUCO by April 1, 2022. Such a study for the OVEC Units would show a reasonable retirement date and provide guidance to the PUCO on whether to approve collection of costs for future

investments for environmental compliance, which I discussed earlier in my testimony.

The PUCO should also require that Duke evaluate operational changes at the OVEC units, including switching to seasonal operations to keep the plans offline during months with low market prices, and lowering the minimum operating level of the units so that OVEC has more flexibility to ramp each unit down when they are online during periods of low market prices.

Q63. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION REGARDING DISALLOWANCES RELATING TO THE OVEC UNITS?

A63. The PUCO should disallow in this proceeding $24.6 million in above-market costs that Duke collected from consumers under the Price Stabilization Rider.

VIII. CONCLUSION

Q64. DOES THIS CONCLUDE YOUR TESTIMONY?

A64. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Devi Glick, on Behalf of the Office of the Ohio Consumers' Counsel* (Public Version) was served via electronic transmission upon the parties below this 26th day of October 2021.

/s/ John Finnegan
John Finnegan
Assistant Consumers' Counsel

The PUCO's e-filing system will electronically serve notice of the filing of this document on the following parties:

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Devi Glick, Principal Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, June 2021- Present; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.

- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Glick, D., P. Eash-Gates, S. Kwok, J. Tabernero, R. Wilson. 2021. *A Clean Energy Future for Tampa.* Synapse Energy Economics for Sierra Club.

Glick, D. *2021. Synapse Comments and Surreply Comments to the Minnesota Public Utility Commission in response to Otter Tail Power's 2021 Compliance Filing* Docket E-999/CI-19-704. Synapse Energy Economics for Sierra Club.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

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Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

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Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

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Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

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Public Service Commission of South Carolina (Docket No, 2021-3-E): Direct Testimony of Devi Glick in the matter of the annual review of base rates for fuel costs for Duke Energy Carolinas, LLC (for potential increase or decrease in fuel adjustment and gas adjustment). On behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy. September 10, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

Michigan Public Service Commission (Docket No. U-20530): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ending December 31, 2020. On behalf of the Michigan Attorney General. August 24, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase I Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan. On behalf of the Sierra Club. December 31, 2019.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated September 2021

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE NORTHERN DISTRICT OF OHIO
AKRON DIVISION

In re:	Chapter 11
FIRSTENERGY SOLUTIONS CORP., *et al.*,[1]	Case No. 18-50757 (Request for Joint Administration Pending)
Debtors.	Hon. Judge Alan M. Koschik

EXPERT DECLARATION OF JUDAH L. ROSE IN SUPPORT OF: (1) THE MOTION OF FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC FOR PRELIMINARY AND PERMANENT INJUNCTION AND *EX PARTE* TEMPORARY RESTRAINING ORDER AGAINST THE FEDERAL ENERGY REGULATORY COMMISSION; (2) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT CERTAIN ENERGY CONTRACTS; AND (3) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT A CERTAIN MULTI-PARTY INTERCOMPANY POWER PURCHASE AGREEMENT WITH THE OHIO VALLEY ELECTRIC CORPORATION

I, Judah L. Rose, hereby declare under penalty of perjury:

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

2. I respectfully submit this expert Declaration in support of (i) *the Motion of FirstEnergy Solutions Corp.* ("FES") *and FirstEnergy Generation, LLC* ("FG") *for Permanent and Preliminary Injunction and Ex Parte Temporary Restraining Order Against the Federal Energy Regulatory Commission* ("FERC") in the above captioned adversary proceeding; (ii) *the Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject Certain Energy*

[1] The Debtors in these chapter 11 cases, along with the last four digits of each Debtor's federal tax identification number, are: FE Aircraft Leasing Corp. (9245), case no. 18-50759; FirstEnergy Generation, LLC (0561), case no. 18-50762; FirstEnergy Generation Mansfield Unit 1 Corp. (5914), case no. 18-50763; FirstEnergy Nuclear Generation, LLC (6394), case no. 18-50760; FirstEnergy Nuclear Operating Company (1483), case no. 18-50761; FirstEnergy Solutions Corp. (0186); and Norton Energy Storage L.L.C. (6928), case no. 18-50764. The Debtors' address is: 341 White Pond Dr., Akron, OH 44320.

Contracts; and (iii) *the Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject a Certain Multi-Party Intercompany Power Purchase Agreement with the Ohio Valley Electric Corporation.*

3. I received 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 35 years. I am an Executive Director and 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 approximately 5,000 professionals to have received ICF's honorary title of Distinguished Consultant.

4. ICF works with a variety of clients across the private and public energy sectors including governmental entities (such as the Federal Energy Regulatory Commission, the U.S. Department of Energy, state regulators and energy agencies), and private companies such as 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 and similar organizations. I have personally consulted with or testified as an energy industry expert on behalf of most of the listed clients.

5. I have extensive experience in assessing wholesale electric power market design and regulation. I also have extensive experience forecasting wholesale electricity prices, power plant operations and revenues, transmission flows, and fuel prices (e.g., coal, natural gas,

renewable energy). I also have extensive experience in valuing individual power plants in the context of projected market conditions.

6. ICF was retained by counsel to the Debtors in April of 2017 to calculate the losses to the Debtors associated with: (a) eight burdensome executory power purchase agreements (the "PPAs") under which FES buys energy, capacity, and renewable energy credits ("RECs"); and (b) a certain multi-party intercompany power purchase agreement with the Ohio Valley Electric Corporation (as amended and restated, the "OVEC ICPA" and together with the PPAs, the "Executory PPAs"). Specifically, ICF was retained to determine the short and long-term costs of continued performance. ICF performed an initial analysis of the Executory PPAs in mid-2017, and then updated its work commencing in January 2018.

7. The background of the Executory PPAs, which expire between 2024 and 2040, is described in greater detail in the Declaration of Kevin T. Warvell. At the time ICF was retained, the Debtors had already identified these contracts as burdensome and unnecessary to their business, and had performed preliminary calculations. I, along with my colleague David Gerhardt, have reviewed documents made available to me by counsel, including the Executory PPAs, and numerous operational and financial reports from the Debtors, and performed other investigations to determine the facts and circumstances in this declaration. This declaration is based on my personal knowledge and a review of relevant documents and various calculations and data. I have used principles generally accepted in the energy markets for estimating the costs to the Debtors of the Executory PPAs and forecasting the future value of energy and renewable energy credits. If called as a witness, I could and would testify competently thereto.

8. Market circumstances have resulted in an extended period of commodity prices and REC prices much below those prices found in the Executory PPAs. The main drivers to the collapse in prices include:

- Lower natural gas prices due to continued improvements in natural gas fracking;
- Excess generating capacity due in part to lower than expected load growth;
- Lower cost of construction for renewable technologies, and/or improved performance (*e.g.*, higher capacity factors); and
- Surplus of RECs.

Taken together, these market forces have decreased wholesale electricity prices, and prices of RECs, to levels not envisioned at the time the Executory PPAs were signed. Such market forces have prevailed for the last three to four years and are now expected to continue for the next few years, at a minimum.

9. ICF has individually assessed the Executory PPAs to determine the estimated losses to FES and FG of performing such contracts over their lifetime. These calculations took into account the length of the contracts, the contract price, the expected volume using historical data, and the expected revenue streams. With respect to the OVEC ICPA, ICF took into account both fixed and variable costs such as fuel, coal, variable and fixed operations and management costs, capital expenditures, financing costs and emissions costs associated with that agreement. ICF's calculations used an internal production cost model which simulated the specific power markets in which the Ohio Valley Electric Corporation ("OVEC") and the other contract counterparties operate.

10. To determine the future losses, ICF compared the cost of the contracts over their lifetime with the forecasted future power prices in the market. In forecasting these rates, ICF looked separately at energy price, capacity price, and REC price. For the years 2018-2020, ICF was able to use the actual PJM auction price for capacity prices.[2] For energy prices and for capacity prices in later years, ICF used both a long-term 30-year pricing model and an annual model maintained in the ordinary course of business by ICF specific to the PJM marketplace which takes into account the individual players in that marketplace.

11. The assumptions underlying all calculations in the model are the results of external inputs such as OVEC production cost projections and NYMEX futures, as well as internal inputs which reflect the views of ICF's nationally recognized power practice group, which includes decorated experts in natural gas, coal, renewable energy, power modeling and energy markets. The inputs drawn from ICF's data and model are used by ICF generally (as then currently maintained) in all of its advisory, consulting and expert testimony work related to the future performance of the PJM market.

12. Based on the above-described analysis, I concluded that the estimated cost of maintaining the Executory PPAs to the estate would be $765 million on an undiscounted basis from April 1, 2018 to December 31, 2040. On a net present value ("NPV") basis over this same time period, and using a 7% discount rate, the estimated cost to the estate would be $475 million.

[2] "PJM" is PJM Interconnection, LLC. FES and FG conduct all of their business operations within the regional transmission organizations overseen by PJM, which is a regional transmission organization that covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates, controls, and monitors multi-state electricity grids, and controls generation and transmission operations 24 hours a day, providing instructions to producers to ensure that the electric grid performs as desired.

In the near term (i.e., 2019-2023), the cost to the estate would be approximately $58 million per year.

13. Based on my review of the Warvell Declaration and diligence respecting FES generally, the capacity, power and RECs purchased under the Executory PPAs are unnecessary to FES's business, and the rejection of such agreements will not adversely impact FES's compliance with any other capacity, generation or retail obligations or the price or availability of power within PJM.

14. The estimated costs reflect an expected or base case. This case is based on available information about market and regulatory conditions. I have also examined sensitivity cases and all cases show high estimated damages. In the event of new information becoming available, I may update or refine these estimates.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

DATED:

Respectfully submitted,

Judah L. Rose

UNITED STATES BANKRUPTCY COURT
NORTHERN DISTRICT OF OHIO
EASTERN DIVISION

In re:	)	Chapter 11
	)	
	)	Case No. 18-50757
FIRSTENERGY SOLUTIONS CORP., *et al.*,[1]	)	(Request for Joint Administration Pending)
	)	
Debtors.	)	
	)	Hon. Judge Alan M. Koschik
	)	

DECLARATION OF KEVIN T. WARVELL IN SUPPORT OF: (1) THE MOTION OF FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC FOR PRELIMINARY AND PERMANENT INJUNCTION AND *EX PARTE* TEMPORARY RESTRAINING ORDER AGAINST THE FEDERAL ENERGY REGULATORY COMMISSION; AND (2) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT CERTAIN ENERGY CONTRACTS; AND (3) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT A CERTAIN MULTI-PARTY INTERCOMPANY POWER PURCHASE AGREEMENT WITH THE OHIO VALLEY ELECTRIC CORPORATION

I, Kevin T. Warvell, hereby declare under penalty of perjury:

1. I am the Vice President, Chief Financial Officer, Treasurer and Corporate Secretary for FirstEnergy Solutions Corp. ("FES"). I have been employed by the Debtors since 2001, initially as a Manager of Business Services, and I subsequently served as Director of Planning Analysis, Director of Wholesale Power/Transmission Utilization, and Director of Rate Strategy. I was promoted to my current position in January 2011. I am familiar with the Debtors' day-to-day operations and business affairs, and I am specifically familiar with the

[1] The Debtors in these chapter 11 cases, along with the last four digits of each Debtor's federal tax identification number, are: FE Aircraft Leasing Corp. (9245), case no. 18-50759; FirstEnergy Generation, LLC (0561), case no. 18-50762; FirstEnergy Generation Mansfield Unit 1 Corp. (5914), case no. 18-50763; FirstEnergy Nuclear Generation, LLC (6394), case no. 18-50760; FirstEnergy Nuclear Operating Company (1483), case no. 18-50761; FirstEnergy Solutions Corp. (0186); and Norton Energy Storage L.L.C. (6928), case no. 18-50764. The Debtors' address is: 341 White Pond Dr., Akron, OH 44320.

Debtors' negotiation, execution and performance of its wholesale energy contracts, including the Executory PPAs, defined below.

2. I submit this declaration in Support of (i) the *Motion of FES and FirstEnergy Generation, LLC* ("FG") *for Permanent and Preliminary Injunction and Ex Parte Temporary Restraining Order Against the Federal Energy Regulatory Commission* ("FERC") in the above captioned adversary proceeding; and (ii) the *Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject Certain Energy Contracts* (the "Rejection Motion"); and (iii) *the Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject a Certain Multi-Party Intercompany Power Purchase Agreement with the Ohio Valley Electric Corporation* (the "OVEC ICPA Rejection Motion", collectively, with the Rejection Motion, the "Rejection Motions").

3. By the Rejection Motions, the Debtors are seeking to reject certain long-term power purchase agreements (the "Executory PPAs"). As explained below, the Executory PPAs are executory contracts, running many years into the future, and are wholly unnecessary to the Debtors' business. The Executory PPAs constitute a very small and insignificant part of the Debtors' overall business, but impose a very significant financial burden that threatens the Debtors' ability to restructure. The Executory PPAs comprise the PPAs (defined in Paragraph 6) and the OVEC ICPA (defined in Paragraph 17).

The Renewable Power Purchase Agreements

4. Renewable portfolio standards ("RPS") obligate *retail* sellers of electricity to obtain a certain percentage or amount of their power supply from renewable energy sources. States develop their RPS programs individually, and each RPS mandate has its own parameters, rules, and requirements, especially with respect to qualifying generation sources, renewable

resource goals (usually expressed as a percentage of total load), and target dates for compliance. RPS requirements may be met by obtaining renewable energy credits ("RECs") that provide evidence that power has been generated by a qualifying renewable resource.

5. RECs provide evidence of the generation of electricity from a qualifying renewable facility. Typically, one REC is created for every megawatt-hour (MWh) of energy produced from a qualifying facility. The RECs may be sold with the power or separately. The ability to realize income from the sale of RECs is a contributor to the economics of a renewable facility.

6. FES presently sells power to retail customers in Illinois, Maryland, Michigan, New Jersey, Ohio, and Pennsylvania. Historically, FES obtained the necessary RECs through eight power purchase agreements that Plaintiffs entered with various counterparties between 2003 and 2011 (collectively, the "PPAs"),[2] each of which obligates FES to purchase renewable energy and the accompanying RECs at specified prices during the term of the agreement. These PPAs have remaining terms running to various end dates between 2024 and 2033. The counterparties supply their power directly to the grid; under the terms of the PPAs it is deemed as a financial matter to have been bought by Plaintiffs (at the contract price) and re-wholesaled back into the local Regional Transmission Organization at current market prices.

7. The contract price in each of the PPAs is a "bundled" price that includes the cost of power, RECs, capacity and ancillary services. The PPAs together represent a very small portion of the aggregate energy (less than 3%) the Debtors generate and/or acquire from others.

8. The PPAs and a summary of their material terms is below:

[2] Also included in the definition of "PPAs" as used herein is a certain power purchase agreement with Forked River Power, LLC, a dual-fuel fired cycle combustion turbine power producer.

a. Wind Power Purchase Agreements between FES and Allegheny Ridge Wind Farm, LLC (Phase 1 and Phase 2)
Contract Date: March 21, 2006
Termination Date: December 31, 2030
Contract Price: $65.00/MWh

b. Power Purchase Agreement between FES and Blue Creek Wind Farm LLC[3]
Contract Date: February 8, 2011
Termination Date: December 31, 2032
Contract Price: $61.91-88.08/MWh[4]

c. Wholesale Purchase and Sale Agreement for Wind Energy between FES and Casselman Windpower LLC
Contract Date: November 30, 2006
Termination Date: 23rd Anniversary of Delivery Commencement Date
Contract Price: $72.49-94.72/MWh[5]

d. Renewable Resource Power Purchase Agreement between FES and High Trail Wind Farm, LLC

[3] Blue Creek Wind Farm is presently in default on this agreement. FES reserves all rights under this agreement, including the right to terminate the contract per its terms, rendering rejection unnecessary.

[4] Contract Price escalates during each year of the term as follows: January 1, 2018 through December 31, 2018: $61.91/MWh; January 1, 2019 through December 31, 2019: $63.49/MWh; January 1, 2020 through December 31, 2020: $65.11/MWh; January 1, 2021 through December 31, 2021: $66.77/MWh; January 1, 2022 through December 31, 2022: $68.48/MWh; January 1, 2023 through December 31, 2023: $70.22/MWh; January 1, 2024 through December 31, 2024: $72.01/MWh; January 1, 2025 through December 31, 2025: $73.85/MWh; January 1, 2026 through December 31, 2026: $75.73/MWh; January 1, 2027 through December 31, 2027: $77.67/MWh; January 1, 2028 through December 31, 2028: $79.64/MWh; January 1, 2029 through December 31, 2029: $81.67/MWh; January 1, 2030 through December 31, 2030: $83.76/MWh; January 1, 2031 through December 31, 2031: $85.89/MWh; January 1, 2032 through December 31, 2032: $88.08/MWh.

[5] Contract Price escalates during each year of the term as follows: December 1, 2017 through November 30, 2018: $72.49/MWh; December 1, 2018 through November 30, 2019: $74.00/MWh; December 1, 2019 through November 30, 2020: $75.53/MWh; December 1, 2020 through November 30, 2021: $77.10/MWh; December 1, 2021 through November 30, 2022: $78.71/MWh; December 1, 2022 through November 30, 2023: $80.35/MWh; December 1, 2023 through November 30, 2024: $82.00/MWh; December 1, 2024 through November 30, 2025: $83.70/MWh; December 1, 2025 through November 30, 2026: $85.50/MWh; December 1, 2026 through November 30, 2027: $87.30/MWh; December 1, 2027 through November 30, 2028: $89.10/MWh; December 1, 2028 through November 30, 2029: $91.0/MWh; December 1, 2029 through November 30, 2030: $92.90/MWh; December 1, 2030 through end of Term: $94.72/MWh.

Contract Date: September 14, 2007
Termination Date: 18th Anniversary of Facilities Completion Date/Facilities Completion Termination Deadline
Contract Price: varies by year, month and hour; average annual price is approximately $70.8/MWh

e. Power Purchase Agreement between FES and Krayn Wind LLC
Contract Date: August 20, 2008
Termination Date: December 31, 2030
Contract Price: $91.02-105.13/MWh[6]

f. Power Purchase Agreement between FES and Maryland Solar LLC
Contract Date: October 14, 2011
Termination Date: 20th Anniversary of Commercial Operation Date
Contract Price: $230.00/MWh

g. Master Power Purchase and Sale Agreement between FES and Meyersdale Windpower LLC
Contract Date: April 21, 2003
Termination Date: 20 year anniversary of Commercial Operation Date
Contract Price: $39.60/MWh

h. Wind Power Purchase Agreements between FES and North Allegheny Wind LLC (Phase 3 and Phase 4)
Contract Date: September 18, 2006
Termination Date: 23rd Anniversary of Commercial Operation Date
Contract Price: $74.00/MWh for years 1-12, $68.00/MWh thereafter

i. Master Power Purchase & Sale Agreement between FES and Forked River Power, LLC[7]
Contract Date: April 17, 2008
Termination Date: April 17, 2018
Contract Price: Variable based upon specified ratio

9. At the time the PPAs were entered between 2003-2011, they were necessary and appropriate for FES's business because: (a) FES's actual and projected retail sales were greater

[6] Contract Price escalates during each year of the term as follow: 2018: $91.90/MWh; 2019: $92.08/MWh; 2020: $93.74/MWh; 2021: $94.71/MWh; 2022: $95.72/MWh; 2023: $96.76/MWh; 2024: $97.83/MWh; 2025: $98.95/MWh; 2026: $100.10/MWh; 2027: $101.29/MWh; 2028: $102.53/MWh; 2029: $103.81/MWh; 2030: $105.13/MWh.

[7] The damages calculations discussed in this declaration do not include those associated with the Master Power Purchase & Sale Agreement between FES and Forked River Power, LLC. This contract will terminate by its own terms on April 17, 2018.

than they are today; (b) market prices and outlook for power and RECs were materially greater than the current environment; (c) RPS mandates were more demanding than today; and (d) the supply of RECs was more limited. At that time, a bundled PPA was typically the only way to contract for RECs in the long-term at a fixed price. Additionally, many states had requirements that a certain percentage of the RECs had to be generated in-state.

10. However, many state-specific RPS mandates have since been relaxed and there are now an abundance of RECs available for purchase. While the PPAs made sense to FES at the time they were entered into, a dramatic downturn in the energy market and prices of RECs now renders these contracts extremely burdensome and uneconomic to FES.

11. For example, pursuant to its PPA with Krayn Wind LLC for 2018, FES is obligated to pay a fixed amount of $91.02 per MWh (and associated REC), escalating to $105.13 per MWh (and associated REC) by 2030. This is nearly three times today's market value of $36.00 for such power and REC. Based on current expectations, FES will lose approximately $103 million over the remaining term of this one PPA alone.

12. The PPAs are all the more burdensome to the Debtors because FES does not have any business or regulatory need for the power, the RECs or the standby capacity that the Debtors receive under the PPAs. FES previously made the determination to phase out its retail business, and currently sells substantially less power in the retail market than it did just four years ago. In 2013, FES sold more than 110 terawatt hours ("TWh") of power. This year, FES expects to sell less than half of that amount. Crucially, FES's need for RECs is tied directly to its retail business, and such need will be eliminated entirely once FES has fully exited that business (at the conclusion of a successful bankruptcy process.)[8]

[8] FES is in the process of marketing its retail business for sale (the "Retail Book Sale").

13. Today, FES has enough of a surplus of RECs in inventory to engage in its retail business for three years. In fact, FES has such an excess of RECs in its inventory that it is currently selling those excess RECs in the open market. However, as FES expects to sell its entire retail business in the near term, it does not need to purchase additional RECs. Nor does FES have any other need for the power or capacity provided by the PPAs.

14. In 2016, FES determined that the PPAs were burdensome and began to attempt to quantify the losses to FES associated with these agreements over the near term. We estimated that such losses would be approximately $40 million to $50 million per year. In April 2017, Debtors' counsel retained ICF to perform more exacting calculations and to conduct such analysis through the end date of the PPAs, *i.e.* 2024-2033. I am familiar with ICF and believe they are well qualified to perform these calculations.

15. The power bought and sold under the PPAs constituted approximately less than 3% of FES's total wholesale business in 2017, yet the PPAs impose enormous losses. ICF has projected that FES will lose approximately $500 million on an undiscounted basis if FES is required to perform under the PPAs through the end of the contract terms. Those calculations are summarized in the accompanying Declaration of Judah Rose. I have reviewed that declaration and the attached calculations and I concur with ICF's assumptions, methodology and conclusions.

16. Because losses of this magnitude would impose an unsustainable financial burden on the Debtors, and because FES no longer has a need for the RECs which justified its entry into the PPAs in the first place, I concluded that the PPAs should be rejected.

The OVEC Intercompany Power Purchase Agreement

17. FG is a party to a multi-party intercompany power purchase agreement (the "OVEC ICPA") pursuant to which it and several other power companies "sponsor" and purchase power generated by fossil fuel from the Ohio Valley Electric Corporation ("OVEC").[9] The OVEC ICPA obligates FG to purchase 4.85% of the power that OVEC's fossil-fuel plants generate at an uneconomic rate until either the year 2040 or until OVEC ceases to operate. Last year, this resulted in FG purchasing approximately 0.6 TWh.

18. In 2017, the OVEC ICPA accounted for roughly 1.1% of the power FES sold at wholesale, yet the losses associated with this contract are enormous. ICF has calculated that FG would lose $268 million on an undiscounted basis if FG was required to perform under the OVEC ICPA through the end of the contract term.

19. As with the PPAs, losses of this magnitude would impose an unsustainable financial burden on the Debtors. Accordingly, I concluded the OVEC ICPA should be rejected.

No Effect on Power Supply

20. FES and FG conduct all of their business operations within the regional transmission organizations ("RTOs") overseen by PJM Interconnection LLC ("PJM"), which is a regional transmission organization that covers all or parts of Ohio, Pennsylvania, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM coordinates, controls, and monitors

[9] OVEC is owned jointly by: American Electric Power; Buckeye Power Generating; Dayton Power and Light Company; Duke Energy Ohio; LG&E and KU Energy; FirstEnergy; Vectren South; and Peninsula Generating Cooperative.

multi-state electricity grids, and controls generation and transmission operations 24 hours a day, providing instructions to producers to ensure that the electric grid performs as desired.

21. The total amount of energy bid/sold into PJM during 2017 was approximately 767 TWh. The power that FES and FG purchased under the Executory PPAs during 2017 was just 1.9 TWh, or 0.2% of the available energy in PJM. Further, the energy, capacity and RECs previously purchased by FES or FG will remain available for sale by the producers to PJM or to other wholesale suppliers because all such counterparties are connected directly to the PJM grid.

22. Given the foregoing, I cannot conceive how the rejection of the Executory PPAs will cause any disruption to the continued supply of wholesale electricity within our areas of operation, or impact the reliability of the transmission grid.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Dated:

Respectfully submitted,

Kevin T. Warvell
Vice President, Chief Financial Officer,
Treasurer and Corporate Secretary,
FirstEnergy Solutions Corp.