STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of INDIANA MICHIGAN POWER COMPANY for approval of a Power Supply Cost Recovery Plan and Factors (2025)	)))))	**Case No. U-21596**

Direct Testimony of Devi Glick

On Behalf of Attorney General Dana Nessel, Citizens Utility Board of Michigan, and Sierra Club

Public Version

March 4, 2025

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A 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.

Q Please summarize your work experience and educational background.

A 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, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony in over 60 different proceedings before state utility regulators in more than 20 states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as widely used optimization and electric dispatch models. I have directly run the EnCompass and PLEXOS electricity system models and have reviewed inputs and outputs for several other 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 12 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit AG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Dana Nessel, Attorney General of Michigan, Citizens Utility Board of Michigan, and Sierra Club.

Q Have you testified previously before the Michigan Public Service Commission ("Commission" or "MPSC")?

A Yes, I submitted testimony in the following Cases:

- Case No. U-21260 DTE Energy's ("DTE") PSCR reconciliation docket for 2023
- Case No. U-21662 DTE's Public Act 295 compliance docket
- Case No. U-21262, Indiana Michigan Power Company's ("I&M") Power Supply and Cost Recovery ("PSCR") reconciliation docket for 2023
- Case No. U-21051, DTE's PSCR reconciliation docket for 2022
- Case No. U-21427, I&M's PSCR Plan for 2024

- Case No. U-20805, I&M's PSCR reconciliation docket for 2021
- Case No. U-21261, I&M's PSCR Plan for 2023
- Case No. U-21052, I&M's PSCR Plan for 2022
- Case No. U-20528, DTE's PSCR reconciliation docket for 2020
- Case No. 20530, I&M's PSCR reconciliation docket for 2020
- Case No. 20804, I&M's PSCR plan for 2021
- Case No. 20224, I&M's PSCR reconciliation docket for 2019

Q What is the purpose of your testimony in this proceeding?

A I review and evaluate the prudence of I&M's PSCR Plan for 2025 and for the five-year forecast period (2025–2029). Specifically, I evaluate I&M's justifications for continuing to charge Michigan customers above-market prices for the purchase of energy and capacity from its affiliate, Ohio Valley Electric Corporation ("OVEC") under the Inter-Company Power Agreement ("ICPA") and I review the failure of I&M and its parent company American Electric Power Company (AEP) to exercise prudent oversight of OVEC's operational and planning decisions. In addition, I review fuel and power purchase costs at Rockport Unit 1 that I&M plans to pass on to customers during the PSCR plan year and five-year forecast period. I also summarize the increasing costs and risks that I&M is imposing on its ratepayers by continuing to rely on its coal-fired power plants for capacity and energy.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations.

In Section 3, I review the costs that I&M plans to pass on to its customers for the purchase of power from OVEC under the ICPA during the PSCR plan year (2025) and the five-year forecast period (2025–2029) and the value of the services provided to I&M customers based on market energy revenue and capacity value. I discuss how these projections continue a pattern of I&M customers paying unreasonable prices to OVEC for power under the ICPA without I&M taking any proactive steps to address this problem. I discuss how I&M has been imprudently managing the ICPA by remaining ignorant of OVEC's operational and planning decisions. Finally, I outline my recommendations to the Commission to disallow inclusion of ICPA costs above market value in its maximum PSCR factor and to caution I&M that the Commission should once again disallow recovery of costs above market value in future reconciliation dockets.

In Section 4, I review the costs and operational practices that I&M modeled for Rockport Unit 1 in its creation of its 2025 PSCR Plan and its five-year forecast of power supply costs, as well as the value of the services provided back to I&M customers (market energy revenues and capacity value). I recommend that the Commission caution I&M that on the basis of present evidence it may disallow recovery of future excess costs from Rockport based on uneconomic commitment practices.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of I&M witnesses associated with this proceeding. I also rely on public information associated with prior I&M proceedings. To a limited extent, I also rely on certain external, publicly available documents such as PJM's *State of the Market* and *Cost of New Entry* reports and public data obtained through discovery from other regional utilities and Freedom of Information Act requests.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. OVEC currently maintains and operates its two power plants, Clifty Creek and Kyger Creek, uneconomically. Further, OVEC is projected to continue this practice based on I&M's own data and projections. I&M estimates it will incur excess costs of $48.1 million in energy market revenue and capacity value over the five-year PSCR forecast period (2025–2029) (on a present-value basis) by purchasing energy and capacity from OVEC under the ICPA. These costs will be passed on to ratepayers, absent protection from the Commission.

2. I&M's projections for its OVEC power costs over the majority of the PSCR plan period (2025–2029) roughly range between $68.84 and $86.74/MWh.

3. The Commission has ruled that I&M is subject to the MPSC Code of Conduct and, as such, its recovery of payments to an affiliate must be capped at market price. The Company's sustained pattern of paying OVEC above-market prices for power violates the Code of Conduct.

4. I&M is attempting to recover approximately 64 percent of its share of the outstanding debt at the OVEC plants (billed through the ICPA demand charge) through the PSCR factor during the PSCR period. Absent action from the Commission to limit the costs passed on to I&M ratepayers during the PSCR plan period, I&M will be allowed to front-load its collection of outstanding debt from ratepayers and ensure that the Company is insulated from future disallowances while the ratepayers are burdened with the costs.

5. OVEC's 2020 decision to invest over $100 million in Coal Combustion Residuals ("CCR") and Effluent Limitation Guidelines ("ELG") compliance upgrades at the Clifty Creek and Kyger Creek plants has resulted in substantial costs for Michigan ratepayers. I&M's remaining portion of these costs, along with the costs to comply with any new or updated environmental regulations, will be charged to I&M customers during the PSCR plan period.

6. The energy market forecast that I&M relied on for its PSCR plan is high even compared to AEP's most recent fundamental forecast and not properly justified. As a result of the Company's high energy market forecasts, I&M projects much higher utilization of its legacy fossil units this year than last year:

   i. At OVEC, I&M is projecting a jump in utilization up to around a 60 percent capacity factor in 2029. This is in contrast with last year when I&M projected that OVEC's utilization would drop down to 6 percent by 2028.

   ii. At Rockport Unit 1, I&M is now projecting utilization levels between 20 percent and 25 percent during the PSCR period. This is in contrast with last year when I&M projected Rockport 1 would fall below a 17 percent capacity factor during the PSCR Plan period and less than 8 percent in 2028.

Q Please summarize your recommendations.

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

1. The Commission should amend the PSCR plan by removing above-market costs for the OVEC ICPA from the maximum PSCR factor for the plan year. The Commission should reduce I&M's forecast costs by the difference between OVEC's expected costs and the expected cost of market purchases for energy and capacity as measured by an equivalent benchmark during that time period.

2. The Commission should issue a Section 7 warning to I&M that on the basis of present evidence it will likely disallow I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA above-market costs during the PSCR plan period 2025–2029. Specifically, the Commission should indicate that, consistent with its ruling in Case No. U-20530, it will disallow recovery of OVEC costs above the cost of energy and capacity from a comparable benchmark in future PSCR reconciliation dockets.

3. The Commission should only approve I&M's PSCR plan to the extent it is developed around assumptions that Rockport 1 is operated economically (i.e., using an economic commitment status), and that the modeled assumptions are consistent with how the Company actually operates Rockport 1.

4. The Commission should indicate that it will disallow recovery in future PSCR reconciliation dockets of the fuel portion of all net revenue losses incurred as a result of imprudent Rockport unit-commitment decisions.

3. I&M Customers Are Paying Unreasonable Prices to OVEC for Power Under the ICPA

i. I&M purchases power from OVEC under the ICPA

Q What is OVEC and how is it related to I&M ratepayers?

A OVEC is an entity jointly owned by 12 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. OVEC supplies the power from these plants to 13 sponsoring utilities, all but one of which are subsidiaries of the shareholders. The power is provided through a long-term contract called the Inter-Company Power Agreement.[1] Together, the sponsoring utilities are responsible for the fixed and variable costs of OVEC, for which they are billed by OVEC through monthly variable, demand, and transmission charges.

Q Describe the relationship between AEP, I&M, and OVEC.

A AEP is I&M's parent company. AEP[2] owns 43.47 percent of OVEC, making it the largest single owner of OVEC. AEP subsidiaries, including I&M[3], together hold the largest participation share[4] in OVEC (also at 43.47 percent). AEP Service Corp. procures all of the fuel for the OVEC plants. AEP holds three of the seats on the

[1] Ex AG-2, OVEC Annual Report, 2023; Ex AG-3, the ICPA as amended.
[2] American Electric Power Company together with Ohio Power Company.
[3] Appalachian Power Company and Ohio Power Company are the other two AEP sponsoring companies.
[4] OVEC owners or shareholder are responsible for the plant debt. OVEC sponsoring companies are under contract for a share of the power from the OVEC plants (their power participation ratio).

OVEC Board of Directors (out of a total of 12), and AEP subsidiary Appalachian Power Company holds one seat. That is the most seats held by any single entity.[5]

Q Describe the relationship between AEP, I&M, and Indiana-Kentucky Electric Corporation (IKEC).

A IKEC is a wholly owned subsidiary of OVEC. IKEC owns the Clifty Creek plant (OVEC owns the Kyger Creek plant). AEP holds one seat and I&M holds three seats on the board of IKEC out of a total six seats. Those four seats provide AEP and I&M with majority voting control of IKEC and, thereby, of the Clifty Creek plant.[6]

Q Who is the President of OVEC and IKEC?

A Brian Sherrick, Vice President of Generation Shared Services for American Electric Power Services Corporation, was elected president of OVEC and IKEC on October 13, 2023.[7]

Q For what portion of OVEC is I&M responsible?

A I&M's share of the ICPA with OVEC is 7.85 percent.[8] This means that I&M is responsible for 7.85 percent of OVEC's fixed and variable costs while also being entitled to a 7.85 percent share of OVEC's power output. This translates into an installed capacity ("ICAP") share of 166.2 MW.[9] The cost of the ICPA is passed through to I&M ratepayers as a direct cost. During the 2025 PSCR year, I&M

[5] Ex AG-2, OVEC 2023 Annual Report, pages 1 and 43.
[6] *Ibid.*
[7] *Ibid*, page 4.
[8] *Ibid.*
[9] I&M Response to AG Request 1-3, Attachment 1.

projects it will be billed $59 million[10] for 681,029 MWh.[11] This works out to a cost of $86.74/MWh.[12]

Q Has I&M ever sought or received approval from the Commission for its decision to sign the ICPA?

A No. Before 2004, the ICPA was set to expire on December 31, 2005, but the sponsors agreed among themselves to extend the ICPA to 2026. I&M did not seek approval from the MPSC for the decision to enter into the extension.[13]

In September 2010, the sponsors again agreed to a revised ICPA that extended its term until 2040.[14] I&M and all participating utilities are therefore obligated to cover the costs of the OVEC plants through 2040. The Clifty Creek and Kyger Creek Plants will each be 85 years old by the time the ICPA expires. Once again, I&M did not request or receive Commission approval for its decision to enter into a revised ICPA. Other utilities, including I&M's affiliate, Appalachian Power, did seek approval for the decision to sign the 2010 contract from the relevant state commission.[15]

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[10] Figure compiled from I&M Response to AG Request 1-9, Confidential Attachment 1.

[11] Exhibit IM-17 (SAS-4).

[12] Figure compiled from I&M Response to Staff Request 1-01, Attachment 4: U-21596 Exh 14-17 Workpaper, Tab Line 11; Exhibit IM-17 (SAS-4).

[13] Case No. U-20804, Final Order dated November 18, 2021, page 17.

[14] Ex AG-3, ICPA as amended.

[15] In re Application of Appalachian Power Company, Docket No. PUE-2011-00058, Virginia State Corporation Commission, Order Granting Approval, August 3, 2011.

ii. I&M projects to pass on to ratepayers $48.1 million in losses relative to the OVEC units' energy market revenue and capacity value over the next five years by purchasing power under the ICPA

Q How does I&M serve customer load, and which associated costs are at issue in this PSCR docket?

A I&M serves customer load broadly through three types of resources: (1) generation assets owned (or leased) and operated by the Company, (2) power purchased under power purchase agreements ("PPA") from generation assets owned by other entities or affiliates, and (3) PJM market power purchases.

For units owned or leased by I&M, the Company forecasts the fuel costs associated with running the units in the PSCR docket. I&M recovers these costs directly through the PSCR factor. All other operational costs are the subject of separate proceedings (rate cases and riders). For power purchased under PPAs or directly from the market, the Company forecasts the entire cost to operate the units providing the power, not just the fuel costs, in this PSCR docket. I&M recovers these costs directly from customers through the PSCR factor.

Q What did you find about the Company's projected utilization for the OVEC plants going forward?

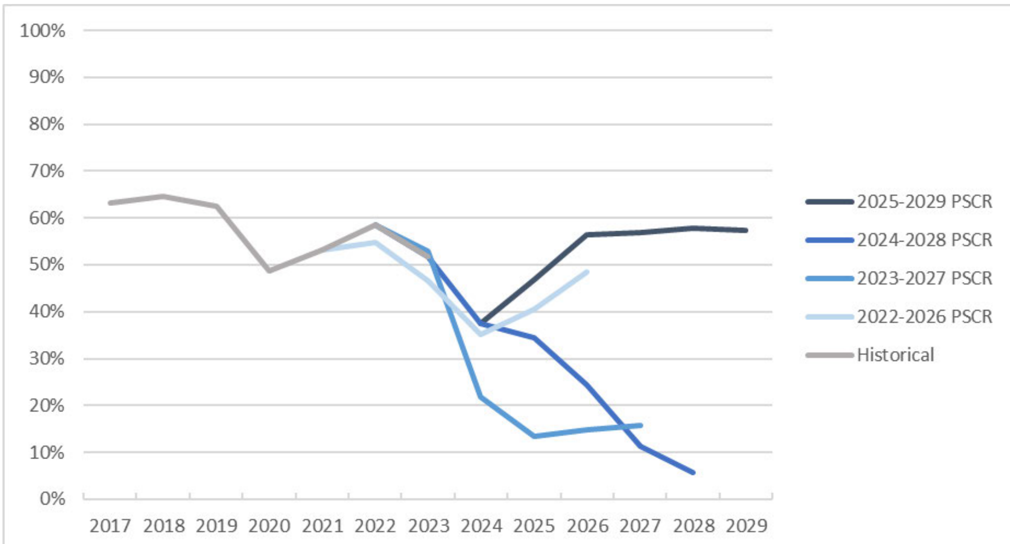
A I found that during the PSCR plan period, I&M projects utilization at OVEC will increase from 47 percent in 2025 up to 57 percent by 2029.[16] This is in contrast with the prior PSCR plan where I&M projected that OVEC's utilization would drop from 37 percent in 2024 down to 24 percent by 2026 and 6 percent by 2028.[17]

[16] Exhibit IM-9 (HAB-9).

[17] Case No. 21427, Exhibit IM-9 (HAB-9).

Figure 1 below show's I&M's capacity factor projection for OVEC for the prior four PSCR plans.

Figure 1. Historical and projected capacity factors for OVEC



Source: Exhibit IM-9 (HAB-9); Case No. 21427, Exhibit IM-9 (HAB-9); Case No. 21052, Exhibit IM-9 (HAB-9); Case No. 21261, Exhibit IM-9 (HAB-9).

Q Have the OVEC plants been a reliable source of capacity?

A No. OVEC's most recent annual report shows an improvement in performance in 2023 relative to 2022, but the units still experienced high outage rates. According to OVEC's most recent annual report from 2023, the combined equivalent availability of the OVEC plants was 75.2 percent in 2023, up from a very poor 66.3 percent in 2022. The combined equivalent forced outage rate (EFOR) for the plants was 5.7 percent in 2023, an improvement from 11 percent in 2022.[18] For the plan

[18] , Ex AG__, OVEC 2023 Annual Report, page 2, compared to OVEC 2022 Annual Report, page 2.

period (2025–2029) OVEC projects that its equivalent availability for the plants will be around [[redacted]] percent and that its EFOR will be [[[redacted]]] percent.[19]

Q **Has OVEC had any challenges with its coal supply?**

A Yes, in last year's PSCR Plan case, I&M witness Scott admitted that the financial health of the coal industry is currently weak, stating that most coal suppliers cannot meet I&M's credit requirements but that suppliers continue to meet their contractual obligations nonetheless.[20]

[[[redacted]][21]

Q **How much is I&M projecting to pay for OVEC power during the PSCR period?**

A As shown in Table 1 below, I&M is projecting to pay $86.74/MWh during the 2025 PSCR plan year, and around $70/MWh for the rest of the plan period.[22] This is

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[19] Figures compiled from I&M Response to Attorney General Request 1-10, CONFIDENTIAL Attachment 1.

[20] Case U-21427, Direct Testimony of Darryl Scott, page 6.

[21] Ex AG-4, I&M Response to Attorney General Request 1-13, CONFIDENTIAL Attachment 1, OVEC Operating Committee Meeting Minutes.

[22] Figures compiled from Exhibit IM-7 (SAS-4); Exhibit IM-20 (JEW-2); and I&M Response to Attorney General Request 1-9, Confidential Attachment 1.

down from I&M's projections last year of costs as high as $414.63/MWh over the PSCR Plan period (2026–2029).[23] These forecasted costs for the PSCR are far above what I&M historically paid for OVEC power, and they reflect a steady increase in the cost per MWh to operate the OVEC plants. With power costs this high, I&M will be paying substantially above market price for power from OVEC over the entire PSCR plan period.

Table 1. Confidential I&M historical and projected power costs for OVEC

Year	Actual costs ($/MWh)	I&M Projected OVEC Costs 2024–2028 2024 PSCR Plan ($/MWh)	I&M Projected OVEC Costs 2025–2029 PSCR 2025 PSCR Plan ($/MWh)
2017	$53.72		
2018	$53.43		
2019	$55.59		
2020	$66.07		
2021	$65.74		
2022	$69.18		
2023	$80.81		
2024	$83.94	$91.87	
2025		$97.54	$86.74
2026		$123.55	$72.94
2027		$225.34	$72.10
2028		$414.63	$67.68
2029			$68.84

Sources: Case U-21427, Ex SC-7, I&M Response to Sierra Club Request 1-20, SC 1-20 Supplemental Attachment 1 (revised); I&M Response to Attorney General Request 1-05, Attachment 1; Exhibit IM-7 (SAS-4); Exhibit IM-20 (JEW-2); I&M Response to Attorney General Request 1-9, Confidential Attachment 1; Case 21427, Direct Testimony of Devi Glick at 14.

[23] See Case U-21427, Direct Testimony of Devi Glick at 14.

Q What does it mean that I&M is paying OVEC above-market prices for power?

A If I&M can purchase the energy, capacity, or ancillary services that it needs from the PJM market or another equivalent source at a lower cost than it would pay to purchase power from OVEC under the ICPA, then it is paying above the market price for the OVEC power.

Q Did I&M explain the large change in its projections for OVEC's utilization and cost between this year and last year's PSCR plans?

A No. When asked to explain the difference, I&M stated "OVEC purchase MWH was projected by the PLEXOS simulation model based on its energy price versus the PJM market price, Therefore, the purchase level will vary based on price competitiveness."[24] This answer doesn't explain what factors in the real world are driving the change in market price used in the PLEXOS model.

Company Witness Chilcote briefly addresses the Company's anticipated load growth due to increased electricity demand from data centers, emerging AI technology, and manufacturing.[25] While the influx of data center load has driven up demand for energy and capacity in the PJM market (and therefore increased energy market prices across the PJM), the forecast that I&M provided for its projected monthly market prices is out of step – that is, substantially higher – than other industry forecasts I reviewed.[26] And in fact, as shown in Figure 2, it is out of step with AEP's most recent fundamental forecast (provided by I&M).[27] Given that

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[24] Ex AG-5, I&M Response to Attorney General Request 1-20.

[25] Direct Testimony of Company Witness Chilcote at 6.

[26] Ex AG-6, I&M Response to Attorney General Request 1-9, Confidential Attachment 4.

[27] Ex AG-7, I&M Response to Attorney General Request 1-17, Attachment 1, (AEP Fundamental Forecast, excerpt).

the energy price forecast is what is driving I&M's projected PSCR revenues, this unexplained discrepancy is concerning.

Figure 2. CONFIDENTIAL OVEC and AEP energy price forecasts [[

[redacted]

]] *Sources: Identified above.*

Q And what did you find when you conducted your own forward-going analysis of the ICPA using I&M's and OVEC's own data?

A I found that over the short term (2025–2029) the OVEC units are likely to cost I&M ratepayers $48.1 million in present-value terms more than the market value of services, or an average of $11.6 million per year above market (as shown in Figure 3 below). This works out to a total of $6.0 million over the PSCR period or $1.4 million per year for the Michigan jurisdictional share of I&M share of OVEC.

Figure 3. CONFIDENTIAL Net forecasted OVEC revenues, I&M portion [[

[redacted]

]] *Source: I&M Response to Attorney General Request 1-3, Attachment 1; I&M Response to Attorney General Request 1-9, Confidential Attachment 1; I&M Response to Attorney General Request 1-9, Attachment 3; I&M Response to Attorney General Request 1-9, Confidential Attachment 4.*

Q Explain how you calculated the forward-going value of the ICPA by using the Company's and OVEC's own data.

A I&M provided a monthly projection for the years 2025–2029 of OVEC's estimated power sales (MWh),[28] and billable costs under the ICPA, broken down by energy charges and demand charges.[29] The Company also provided projected monthly energy market prices.[30] Using I&M's GWh projection and the energy price projections, I calculated the value of the energy provided by OVEC. The Company

[28] I&M Response to Attorney General Request 1-9, Confidential Attachment 1.
[29] *Id*.
[30] I&M Response to Attorney General Request 1-9, Confidential Attachment 4.

also provided capacity values[31] and ICAP values[32] for 2025–2029, which I combined to get total capacity revenue. I summed the energy and capacity values and compared the value of the power to the costs OVEC estimates it will bill to find the net value or losses associated with the ICPA. I assumed that the OVEC units dispatched on peak 50.4 percent of the time, which was the average on-peak generation percentage of Clifty Creek and Kyger Creek in 2024 according to public data obtained from the U.S. Environmental Protection Agency's ("EPA") Clean Air Markets Division.[33]

Q What does the capacity value have to be for the OVEC units to appear economic on a forward-going basis?

A In order for the ICPA to be economical on a forward-going basis (that is, for the value of *all* products and services provided by OVEC to I&M to equal the cost of the ICPA assuming the current energy market projections) the capacity portion of OVEC's services would have to be valued at an average of $363.68/MW-Day ($2026) over the PSCR forecast period (2025–2029). That means capacity prices have to not only go that high but be sustained at that level. This is just below the cost of new entry ("CONE") value for PJM calculated by Brattle Group in April 2022 for a new combustion-turbine ("CT") unit at $402/MW-Day in $2026, assuming an online date of June 1, 2026/2027 (Brattle also calculated CONE for new combined-cycle, or CC, unit at $502/MW-Day).[34] CONE is generally used to represent the ceiling for capacity price assumptions. It is not reasonable or prudent to assume capacity prices at this level will ever materialize, let alone be sustained

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[31] I&M Response to Attorney General Request 1-9, Confidential Attachment 3.

[32] I&M Response to Attorney General Request 1-3, Attachment 1.

[33] U.S. Environmental Protection Agency, "Air Markets Program Data," accessed 19 February 2024. Accessible at: https://campd.epa.gov/data/custom-data-download.

[34] Ex AG-8 PJM CONE 2026/2027 Report. Brattle, April 21, 2022. Accessible at https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

over a period of time. High capacity prices serve as signals to the market to build more capacity or otherwise alleviate transmission constraints. Once more capacity is built, prices rebound to lower levels.

Q The PJM capacity auction cleared at a record price for the 2025/2026 delivery year. Is that likely to make the value of the OVEC power positive in the future?

A No. OVEC power is expensive relative to alternatives even when using the 2025/2026 high capacity value. Specifically, capacity prices cleared at $269.92/MW-day for 2025/2026 up from $28.92/MW-day in the last capacity auction.[35] But that is still far below the OVEC demand charge, which works out to an average of $527/MW-day ($2025). Even if OVEC's capacity was valued at the 2025/2026 clearing price for all of the PSCR plan period (2025–2029), OVEC's power would still exceed its market value in every year. This is true even if energy market prices are as high as I&M projects they will be over the PSCR period.

Q How do the cost and value of the ICPA in 2024 compare to the cost and value of the power in recent years?

A Company Witness Johnston admits in his testimony that profits have been down (with negative energy market revenues in 2020, 2023, and 2024 through June) but claims that OVEC has still been profitable on an energy-only basis in most recent years and provides price stability for its customers.[36] But this claim ignores over half of the costs billed by OVEC to I&M for demand charges, which are significantly larger than the associated capacity value. The cost for power under the ICPA has been significantly above market value since at least 2017 (the earliest year for which the Company provided complete data). As shown in Table 2 below,

[35] Ex AG-9, Excerpt of PJM 2025/2026 Base Residual Auction Report, July 30, 2024, p. 8.
[36] *See* Direct Testimony of Todd Johnston, pages 9-10, Table TAJ-2.

this is not a new occurrence or a single-year fluke. It is in fact part of a pattern of poor and steadily worsening performance.

Table 2. OVEC power costs billed to I&M and market value (2017–2023) ($Nominal)

	MWh electricity	Total OVEC charges billed to I&M	Total market value	$/MWh cost	$/MWh value	Net cost/value
2017	937,620	$50,371,649	$35,170,074	$53.72	$37.51	($15,201,575)
2018	958,430	$51,213,688	$41,651,917	$53.43	$43.46	($9,561,770)
2019	926,846	$51,524,985	$32,432,962	$55.59	$34.99	($19,092,024)
2020	721,476	$47,665,070	$20,999,741	$66.07	$29.11	($26,665,329)
2021	790,000	$51,934,879	$36,156,634	$65.74	$45.77	($15,778,245)
2022	867,246	$59,996,210	$66,740,091	$69.18	$76.96	$6,743,881
2023	752,148	$60,825,436	$26,722,284	$80.87	$35.53	($34,103,152)
2024	784,029	$65,810,943	$26,582,355	$83.93	$33.90	($39,228,588)

Source: Ex I&M Response to Attorney General Request 1-05, Attachment 1; I&M Response to Attorney General Request 1-06, Attachment 1; I&M Response to Attorney General Request 1-03, Attachment 2; U-21427 Ex SC-7, Source: 1-20-SC with Revised Att 1; U-21427 Ex SC-3 Source: 1-15-SC with Atts 1-2; PJM State of the Market Reports, Section 5: Capacity.

Revenues and costs spiked in 2022 due to higher market prices and higher overall costs; but as shown in Table 2, 2022 was a highly anomalous year. Market and gas prices fell in 2023 and 2024 and resulted in net losses for the OVEC plants.

Q How do you calculate the cost to ratepayers of OVEC's contract shown in Table 2 above?

A I&M provided the monthly billing from OVEC for 2024, which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees and energy and revenue by month.[37] For 2017–2023, I relied on the public data

[37] I&M Response to Attorney General Request 1-05, Attachment 1; I&M Response to Attorney General Request 1-06, Attachment 1.

I&M provided in Docket U-21427.[38] The Company provided the ICAP values associated with its share of OVEC by month.[39] I estimated a capacity value based on I&M's share of OVEC capacity value received in the PJM Base Residual Auction ("BRA").[40]

To find the net value or cost to ratepayers of the ICPA, I assumed the cost of the OVEC contract was equivalent to the monthly billing from OVEC. I assumed the value of the ICPA would be equal to the sum of the energy, ancillary services, and capacity value, with the latter calculated as if OVEC's capacity were sold into PJM's BRA. In every year except for 2022, I&M customers were billed substantially more for OVEC power than I&M would have received from the PJM market for OVEC's services.

iii. <u>A reasonable price to pay for power under the ICPA should be measured based on the market-equivalent value of the services provided</u>

Q What was the estimated cost of the ICPA to I&M at the time I&M decided to sign the 2010 OVEC contract?

A As referenced in the testimony of Company witness Johnston, AEPSC conducted a "benchmark study," on behalf of OVEC, in 2011 and found that the ICPA was expected to have a cost of $7.51 billion on a present-value basis between the years

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[38] U-21427 Ex SC-7, Source 1-20 SC with Revised Att 1.

[39] I&M Response to Attorney General Request 1-3, Attachment 2; U-21427 Ex SC-3, Source 1-15 SC with Atts 1-2.

[40] PJM RPM Base Residual Auction Results available in PJM State of the Market reports for 2016-2024. Available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024.shtml.

2011 and 2040.[41] This means I&M's share of the contract was expected to cost $589.4 million on a present-value basis in 2011.[42]

Q Did AEP's 2011 benchmark study determine that it was reasonable to extend the ICPA for 30 years?

A No. The 2011 benchmark study, which appears to have been conducted and submitted to the Federal Energy Regulatory Commission ("FERC") *after* I&M agreed to an extension of the ICPA, was a mere seven-page document that compared the cost of OVEC to the levelized cost of new fossil fuel resources. The analysis did not consist of robust forward-looking analysis, did not consider I&M's actual system needs, and did not consider the lowest-cost way to meet those needs. In addition, the Company failed to disclose critical assumptions used by the modelers that were essential to evaluating the reasonableness of the analysis. Also, fundamentally, it is impossible that an analysis conducted after a decision was made could have in fact informed the reasonableness of the decision.

While such an analysis may be acceptable for rough screening purposes, it was in no way sufficient for justifying a decision as consequential as extending a power contract three decades and locking I&M ratepayers into hundreds of millions of dollars in unit costs. Despite this, Company Witness Johnston cites the 2011 benchmark study (as well as the initial 2004 benchmark study) as evidence that the ICPA was more favorable than alternatives.[43]

[41] Ex AG-10 Benchmark Study. April 27, 2011.
[42] *Ibid.*
[43] Direct Testimony of Todd Johnston, pages 6–7.

Q What type of study or analysis should I&M have conducted contemporaneously with its application to extend the contract?

A To evaluate the reasonableness of such a decision, I&M and AEP should have engaged in an optimized resource-planning exercise. As part of this exercise, they should have evaluated system needs, estimated the forward-going cost to operate the units under the ICPA, estimated the likely costs of alternatives, and evaluated risk and uncertainty from, among other things, fuel prices volatility and carbon dioxide prices. This type of exercise is typically performed by utilities and requested by state utility commissions whenever utilities make substantial resource planning decisions.

Q What metrics can be used to benchmark the value of capacity and energy provided by the OVEC units?

A There are several long-term supply comparisons we can use to evaluate whether the costs charged under the ICPA are reasonable and compliant with the MPSC Code of Conduct: These include: (1) the costs billed or paid by other entities for *similar services* provided under short- and long-term PPAs; (2) the cost of replacement capacity resources as represented by the 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; and (4) 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 ICPA relative to each benchmark.

Table 3. OVEC cost benchmarks for 2024 ($2024)

	Capacity cost ($/MWh)	Energy cost ($/MWh)	Total cost ($/MWh)	Excess costs based on benchmark ($million)
OVEC 2023 PSCR cost[1]	$46.80	$37.28	$79.11	NA
OVEC 2024 PSCR cost[2]	$44.94	$37.37	$82.31	
Cost of similar services				
In-year transfer price[3]	n/a	n/a	$62.32	$16.95
Value of CONE & PJM BRA				
CONE – CC plant coming online in 2026[4]	$33.87	$24.48	$58.36	$20.06
PJM base residual auction (BRA)[6]	$2.40	$37.37	$39.77	$34.63

Sources: (1) Docket U-21427, Ex SC-7, I&M Response to Sierra Club 1-20, SC 1-20 Supplemental Attachment 1; (2) I&M Response to Attorney General Request 1-05, Attachment 1.; (3) U-15800 Docket Filing, 2024 MPSC Staff Transfer Price Schedule; (4) Ex AG-8, Brattle PJM CONE Study, 2022; (5) 2023/2024 and 2024/2025 BRA Results, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

Q What is CONE and how does the value of CONE compare to the cost paid under the ICPA?

A CONE is an upper bound to capacity resource value that represents the cost of building new gas-fired generation capacity. If I&M were capacity-constrained, the capacity portion of the ICPA could be valued at PJM's CONE. The PJM value of CONE for a new CC unit is $502/MW-Day (in $2026) for the capacity cost.[44] To find the capacity cost in $/MWh, I first multiplied the $/MW-Day CONE values by the MW of a representative CC plant and then multiplied that by 365 days in a year. I then found the total annual MWh for a new CC unit based on the average annual

[44] Ex AG-8, Brattle PJM CONE 2026/2027 Study (excerpt).

capacity factor of 64 percent,[45] and the representative plant size from the CONE report.[46] I divided the total cost by total MWh to get a capacity cost per MWh.

For the energy cost, I calculated total annual MWh for a representative new CC unit based on Brattle's heat rate and plant size assumptions,[47] and an average annual capacity factor of 64 percent. For natural gas prices, I used I&M's forecast for the TCO Delivery point from AEP's 2025 fundamental forecast.[48] Brattle didn't break out non-fuel variable costs in the CONE report, so I relied on the costs from the gross avoided cost of generation report (discussed below). Brattle assumes that all plants have firm gas contracts, so those costs are already included in the capacity cost. I added together the total capacity and energy cost to get a total cost. This works out to a total value of $60.62/MWh based on CONE of a new CC unit. This incredibly conversative measure of CONE for a new CC unit is far below the cost of OVEC.

Q For context, how does the value of CONE compare to the capacity price from PJM's most recent capacity auction?

A CONE is much higher than the cleared capacity value (auction price) from PJM's 2024/2025 BRA because there remains surplus capacity available for participation in the PJM capacity market. This auction produced a capacity price of $28.92/MW-day for year 2024/2025, which is the lowest it has been in the past 10 auctions.[49]

[45] Natural gas combined-cycle power plants increased utilization with improved technology." U.S. Energy Information Administration, Available at https://www.eia.gov/todayinenergy/detail.php?id=60984#:~:text=The%20CCGT%20capacity%20factor%20rose,delivered%20cost%20of%20natural%20gas.

[46] Ex AG-8, Brattle PJM CONE 2026/2027 Study, April 2022, Table 4.

[47] *Ibid*, Table 4.

[48] Ex AG-7, I&M Response to Attorney General Request 1-17, Attachment 1 (AEP Fundamental Forecast, excerpt).

[49] Ex AG-8, Brattle PJM CONE 2026/2027 Study, April 2022 (excerpt), Table 4.

As discussed above, capacity prices cleared at $269.92/MWh-day in the more recent auction for 2025/2026.[50] But even at this level, it is still far below the OVEC demand charge, which works out to an average of $535.76/MWh-day. Further, high capacity market prices are not expected to be sustained; instead, they send a signal to the market to build more capacity.

Q Why did you include the transfer price as a benchmark in the table?

A I included the transfer price as a benchmark because I&M has proposed to use it as a benchmark in several prior reconciliation dockets. I do not believe the transfer price is an appropriate benchmark because it represents the levelized cost of a new CC gas plant in the year in question and not the 2024 cost, and because I am advised by counsel that the Commission has been critical of the use of the transfer price for purposes outside the renewable energy plan context. However, I do think it is relevant that the projected cost of OVEC power is higher than even the benchmark that I&M has recently proposed to measure it against.

Q What are your conclusions regarding a benchmark for the power purchased from OVEC under the ICPA?

A The power I&M purchased under the ICPA is extremely high cost by any reasonable measure. I have presented several reasonable alternatives in this section, for current fossil resources contracted under similar PPAs, new fossil resources, and new renewable resource bid prices that demonstrate this point. Yet I&M customers are paying as much as $35 million per year in excess of the cost of these long-term supply comparisons.

[50] Ex AG-9, *PJM 2025/2026 Base Residual Auction Report*, July 30, 2024 (excerpt).

iv. <u>I&M's integrated resource plan ("IRP") analysis on OVEC is an outlier among nearly half a dozen forward-going analyses which all confirm my findings that OVEC is projected to be uneconomic to operate going forward</u>

Q When were the most recent forward-going analyses on the economics of maintaining and operating the OVEC units conducted?

A There were several analyses performed between 2015 and the present; I summarize their findings in Table 4 below. The findings of all these analyses, with the exception of the most recent study conducted by I&M, all align with the findings of my own forward-looking analysis of the ICPA. Specifically, they all find that the costs of the OVEC plants are projected to far exceed the value the plants provide to ratepayers going forward.

Table 4. Summary of prior OVEC and ICPA studies

Date Completed	Completed by / for	Finding
November 2021 (updated in August 2022)	I&M in IRP Case No. U-21189[1]	Analysis found that terminating the ICPA in 2030 would cost $54 million more than continuing under it until 2040.
April 2019	FirstEnergy Solutions[2]	Forward-looking analysis of ICPA through 2040; found $267 million in losses relative to market for I&M's share of OVEC. That is $3.4 billion for all of OVEC (2018–2040).
December 2018	Moody's Analytics[4]	Assessment of the OVEC Agreement; found annual losses of $10–$13 million for FES's share. That is $206–$268 million annually for all of OVEC.
March 2017	ICF International, for Duke Energy Ohio[5]	Forward-looking analysis of ICPA: 2018–2025; found $67 million in losses relative to market for I&M's share of OVEC.
2016	AEPSC for AEP[6]	Forward-looking analysis of the ICPA; found the plants would be uneconomic into the 2030s and on a present-value basis the ICPA was projected to have a net negative value.

Source: [1] Ex AG-11 Case # U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf; [2]Ex AG-12 Motion for entry of an order authorizing FirsEnergy Solutions Corp. and FirstEnergy Generation LLC. To reject a certain multi-party Intercompany Poer Purchase Agreement with the Ohio Valley Electric Corporation as of the petition date. (Doc 44. Filed Apr. 1, 2018), In re FirstEnergy Solutions Corp., No. 18-50757 (AMK) (Bankr.ND.Ohio); [3]Ex AG-13 Expert declaration of Judah Rose (Doc. 46, filed Apr. 1, 2018), In re FirstEnergy Solutions Corp., No. 18-50757 (AMK) (Bankr. N.D. Ohio); [4]Ex AG-14 Moody's Investors Service. December 2018. Credit Opinion: Ohio Valley Electric Cooperative.; [5]Revised Public Version of Supplemental Testimony of Mr. Judah L. Rose on behalf of Duke Energy Ohio, Inc. July 10, 2018, at 20, Exhibit 2, Ohio PUC Docket 17-0872-EL-RDR, accessible at http://dis.puc.state.oh.us/CasesByYearIndustry.aspx.;[6] Study was provided as a confidential response to Sierra Club Request 1-45 in Case U-21052.

Q Please explain the purpose and context for the OVEC study that I&M completed as part of the IRP.

A In May 2021, the Commission issued an order in Case No. U-20529 that required I&M to file in its next IRP a net present value ("NPV") analysis of the revenue requirement to terminate the ICPA.[51] On November 30, 2021, I&M presented the results of this analysis, which purported to show that terminating the ICPA in 2030 would cost $28 million more than continuing under it until 2040.[52] The Company subsequently updated its analysis for rebuttal testimony to correct numerous errors and found a cost savings of $54 million.[53] In his testimony in this case, I&M witness Johnston states that modeling of OVEC in the current IRP will be covered in the 2024 Reconciliation Case.[54]

Q Do you have any concerns with I&M's IRP NPV analysis and what it shows about the costs I&M is proposing to pass on to ratepayers during the PSCR plan period?

A Yes. Broadly, I&M assumed ratepayers were responsible for all outstanding debt after the ICPA's termination, an unreasonable assumption given that I&M never received approval from the Commission for the ICPA.

More specifically, the IRP analysis assumes also that OVEC will install upgrades to comply with ELG and CCR requirements to keep the units online through the

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51 Order U-20529, page 22.

52 Ex AG-11, Case No. U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf.

53 Case No. U-21189, Modeling Rebuttal Testimony of Jason Stegall, page 3.

54 Direct Testimony of Todd Johnston page 7.

end of the ICPA in 2040, and that I&M ratepayers are responsible for paying the associated costs through the PSCR factor.

Q Please explain your concerns with I&M passing on ELG and CCR costs to its Michigan ratepayers through the PSCR factor.

A First, as stated above, the Company never received approval for the ICPA, so there should be no presumption that ratepayers are responsible for these ELG and CCR costs. Second, the MPSC does not directly regulate specific investments at the OVEC plants and as such, the Commission has neither approved nor disapproved of the ELG and CCR investments. Therefore, I&M cannot presume it is entitled to cost recovery from Michigan ratepayers for the ELG and CCR investments. The Commission is entitled to disallow recovery of any costs it feels were imprudently incurred.

Third, the Company never performed any analysis that evaluated whether compliance was the best option for ratepayers relative to retirement in 2028 and termination of the ICPA at that time. Fourth, the savings the Company calculated in the IRP study from staying in the ICPA relative to terminating it were spread out over a prolonged period ($54 million between now and 2040).[55] This is in contrast with the large capital costs that the Company is currently passing on, and projecting to continue passing on, to ratepayers during the PSCR period—as well as the substantial annual power market losses the plant incurs every year. And finally, I&M's IRP analysis does not contemplate the impacts that increased carbon regulation will have on continued operation of the plants.

[55] Ex AG-11, Case No U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf; Case No. U-21189, Modeling Rebuttal Testimony of Jason Stegall, page 3.

Q Explain your concerns with I&M's assumptions about how OVEC's remaining debt will be paid off.

A I&M assumes that all remaining OVEC debt will be capitalized, turned into a regulatory asset, amortized, and recovered from ratepayers through rates in the event that the ICPA is terminated in 2030.[56] This assumption is inappropriate as I&M never received approval from the Commission for the ICPA and therefore is not guaranteed recovery of any contract costs. Even more concerning is that the Company's long-term debt schedule shows that the majority of the plants' debt will come due during the PSCR period.[57] And OVEC added to its debt as recently as 2019, taking out a $100 million bond that it has to repay between 2026 and 2029– which is entirely within the PSCR period. I estimate that OVEC will recover approximately $586 million or 64 percent of its projected debt balance (as of December 31, 2023) through demand charges during the PSCR period (2025–2029). By the end of 2030, I estimate that OVEC will have recovered over $775 million of its current debt, with only the debt with a 2040 repayment date remaining (approximately16 percent of its current debt).[58]

Figure 4 below shows how OVEC's debt is projected to change over the remaining life of the ICPA and the portion that OVEC expects to recover during the PSCR plan period (2025-2029). This debt will be repaid through the demand charges OVEC bills to its sponsors. This means that even if the ICPA is terminated in 2030 and I&M is not allowed to recover the OVEC remaining debt post-retirement,

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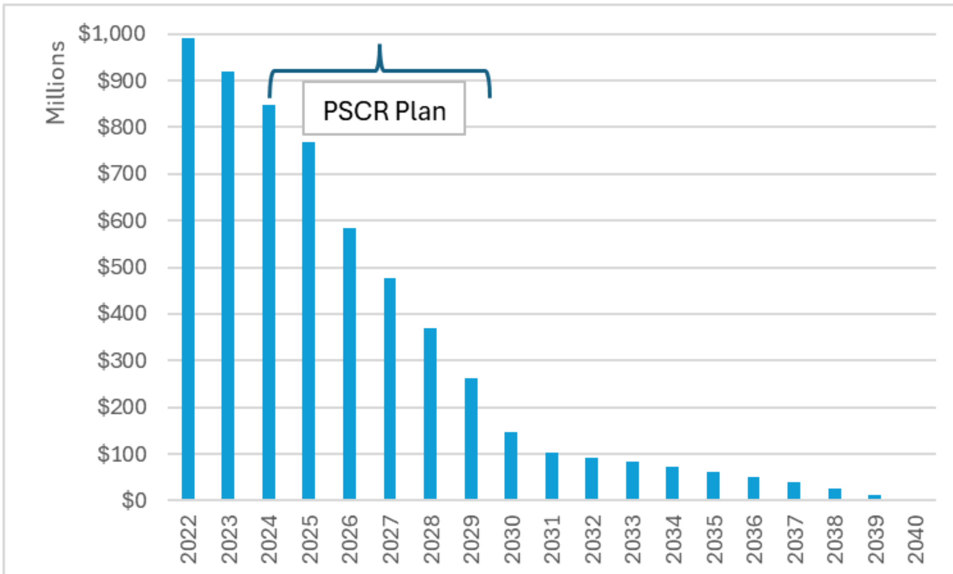
[56] Ex AG-11, Case No. U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf.

[57] Ex AG-2, OVEC 2023 Annual Report at 17-18.

[58] *Id*.

absent action from the Commission, it will already have recovered the majority of its share of the remaining balance from its ratepayers.

Figure 4. Projected long-term debt costs to be included in the demand charges billed under the ICPA



Source: OVEC 2023 Annual Report.

Q What do you conclude based on the results of your own analysis, and the findings of the other forward-looking analyses completed on the value of the ICPA?

A I&M's own data provided as part of this PSCR docket shows that if the Company continues to charge customers for its purchase of power from OVEC under the ICPA, I&M ratepayers will be forced to pay $48.1 million more than the market value of the power over the next five years, $6.9 million of which is Michigan's jurisdictional share. These findings were confirmed by the analyses conducted by several other reputable consulting firms over the past few years. This continues a trend seen since at least 2017 of I&M customers paying substantially more than market equivalent for power under the ICPA (with the exception of 2022 as discussed above).

This all also highlights how much of an outlier I&M's IRP analysis is, based on how much the results deviate from (1) the data that I&M provided in this PSCR docket, (2) the results of every study conducted by OVEC owners in recent years, and (3) the actual experience of OVEC Sponsors since at least 2017. I&M's IRP study is not directionally credible and should not be relied upon.

Finally, based on the substantial losses I&M has incurred from OVEC since 2017 and the additional losses it is projected to continue to incur over the next five years, it is unreasonable for the Company not to take proactive steps to become informed about OVEC's operational and planning decisions and to try to reduce losses and spending.

v. OVEC has invested over $100 million in environmental upgrades at the OVEC plants, some of which will be recovered from Michigan ratepayers during the PSCR period

Q Is or should I&M be involved in decision-making around capital upgrades at the OVEC plants, such as the CCR and ELG compliance projects?

A Yes. Capital upgrade decisions are reviewed and approved by the OVEC and IKEC Board of Directors. As discussed above, I&M and its parent Company AEP and affiliates have four (out of 12 total) seats on the OVEC Board and three (out of six total) seats on the IKEC board. I&M and its affiliates therefore have a large role in the oversight and decision-making for the OVEC plants.

Q Why are the CCR and ELG compliance costs relevant to this PSCR Plan docket?

A These projects, like other capital projects and fixed costs at the OVEC plants, are passed on to sponsoring companies such as I&M through the OVEC demand charge recovered through the PSCR dockets. In a previous docket, I&M acknowledged that costs associated with CCR and ELG capital projects are included in the forecasted demand charges for 2024–2028.[59] I&M did not provide a specific breakdown of the project costs or how those will be recovered through demand charges, stating that the demand charge forecast is created by OVEC and that I&M does not have that information.[60] But looking at the Company's annual reports from 2020–2023, we can tell approximately how much the Company spent on the CCR projects. Specifically, there is a large jump in capital spending in 2021 and 2022 relative to prior years (Table 5). And OVEC indicated in its annual report that 2022 was a heavy construction year at both facilities as the companies executed their CCR compliance strategies.[61] Spending levels in the years before and after the CCR project were around $16 million a year while the two years with CCR construction saw spending levels at $50 million and just below $100 million. This means that the CCR projects likely accounted for at least $120 million in additional capital costs (and likely more). These are costs that no state utility commissions had the opportunity to review or approve.

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[59] Ex AG-16, Case U-21427, I&M Response to Sierra Club Request 3-14.

[60] Ex AG-16, Case U-21427, I&M Response to Sierra Club Request 3-14; I&M Response to Sierra Club Request 3-15.

[61] 2022 OVEC Annual Report at 3.

Table 5. Total construction in progress at OVEC plants ($million)

2019	2020	2021	2022	2023
$13.2	$18.7	$56.0	$99.9	$17.9

Source: OVEC Annual Reports 2020-2023 at 5.

Q How do these project costs compare with I&M's projected revenue or losses from continuing to purchase power under the ICPA?

A I&M's portion of the over $120 million in costs that OVEC is planning to charge its sponsoring companies for the environmental projects is $9.6 million. These are avoidable costs that I&M is proposing to incur and pass on to its ratepayers in the near term. Meanwhile, the Company projected that it would save only $54 million if it continued to operate the OVEC plants beyond 2030 (relative to a scenario where it terminated its OVEC contract in 2030).[62] This means I&M is charging its customers just over $10 million over the next few years for the possibility that it may save $54 million a decade from now (between the years 2030 and 2040). And this omits all consideration of how much I&M is projected to lose relative to the market purchases of energy and capacity over just the next five years. The Company's own data shows these losses are projected to be $48.1 million between 2025–2029. These projections are aligned with the Company's observed losses relative to the market over the previous seven years (2017–2023) which were $113.7 million (see Table 2).

[62] Docket # U-21189, Modeling Rebuttal Testimony of Jason Stegall, page 3.

Q Has the Commission approved the CCR and ELG projects or otherwise approved inclusion of the CCR and ELG capital costs in the OVEC demand charges for the PSCR period?

A No. As discussed above, the MPSC does not directly approve individual investments at the OVEC plants. Additionally, there is no evidence that CCR or ELG retrofit investments at the OVEC plants were discussed in I&M's IRP (which was settled rather than approved on the merits by the Commission).[63]

The Company also did not provide any information to the Commission on the CCR and ELG costs in Case No U-20804 when seeking approval for the 2021 PSCR Plan. Specifically, OVEC included CCR and ELG project costs in demand charges passed on to I&M through the ICPA in 2021. Yet when asked about its role and knowledge of CCR and ELG investments and decisions in that case, I&M claimed that OVEC and not I&M controlled the decision on whether to move forward with environmental upgrades. I&M provided no information to the Commission on estimated CCR and ELG project costs or what retrofit decisions had been made.[64]

Q What is the status of the CCR and ELG projects at Clifty Creek and Kyger Creek?

A OVEC's 2023 Annual Report stated that the Company completed its CCR Rule Part A compliance strategy in 2023. The Report also stated that the Company has taken steps to implement its ELG compliance strategy to meet the 2020 ELG rules. OVEC states that the Company has met its initial deadlines for bottom ash transport water and expects to meet the deadlines for flue gas desulfurization (FGD) in

[63] See Case No. U-21189, I&M Integrated Resource Plan.

[64] Direct Testimony of Devi Glick, Case No. U-20804, page 28.

accordance with each plant's national pollutant discharge elimination system (NPDES) permit.[65]

On January 11, 2022, the EPA issued a conditional denial of the Clifty Creek plant's CCR demonstration application for alternative closure dates. The public notice and comment period on the denial ended on March 25, 2022, and the EPA has taken no final action on the denial as of December 2023.[66] OVEC filed a similar demonstration application for Kyger Creek in November 2020 and has also yet to receive a final ruling (also as of December 2023). But this means that OVEC has not even received approval for all the projects that it has included in the demand charge included in this PSCR plan and which it plans to charge to I&M customers.

Further, in May 2024, EPA released updated ELG rules. OVEC would have to install a further round of ELG compliance projects because its current plan to comply with these ELG bottom ash and FGD wastewater requirements is inadequate. Thus, OVEC's compliance plan is potentially obsolete.

Q Explain why Clifty Creek and Kyger Creek's compliance plans are both likely inadequate.

A At Clifty Creek, according to its November 2022 water permit issued by the Indiana Department of Environmental Management, Indiana-Kentucky Electric Corporation ("IKEC") plans to install a high recycle rate boiler slag handling system to be operational by December 2023. Separately, IKEC plans to install an FGD wastewater treatment plant that would treat FGD wastewater to meet

[65] Ex AG-2, OVEC 2023 Annual Report, pages 3-4.
[66] Ex AG-2, OVEC 2023 Annual Report, page 32.

effluent limits. This is scheduled to be installed by December 2025.[67] But the March 2023 proposed ELG rule would eliminate the use of control technologies that do not achieve zero discharge of both boiler ash and FGD wastewater waste streams.[68] This would render both of Clifty Creek's projects inadequate to achieve compliance with that rule update.

At Kyger Creek, according to a water permit filing made with Ohio EPA,[69] OVEC stated that it expected to complete construction of the ELG projects that would be designed to achieve compliance by November 2022. But the boiler slag wastewater system that OVEC claims to have installed at Kyger Creek would not achieve the zero-discharge requirement of the March 2023 proposed rule. Thus, if that rule is finalized as proposed, Kyger Creek will have to either retire or incur additional costs to comply with the updated rule. The fact that OVEC chose compliance options at both plants that are not permissible long-term solutions highlights the problem with I&M and its parent company AEP failing to supervise resource planning for these plants. This failure to supervise capital spending at these plants is a further reason why this Commission should not permit I&M free rein to recover OVEC's debt from Michigan customers through the PSCR factor.

[67] Clifty Creek NPDES Permit No. IN0001759 application. November 29, 2022. Pages 97-98. Available at https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83395202&dDocName=83397697&Rendition=web&allowInterrupt=1&noSaveAs=1.

[68] Pre-Publication Notice, U.S. EPA, Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power, Mar. 7, 2023, p. 11 of 285 (summarizing rule's as establishing "A zero-discharge limitation for all pollutants in FGD wastewater and [bottom ash] transport water."), Available at: https://www.epa.gov/system/files/documents/2023-03/Prepublication%20FRN_OW_Steam%20Electric%20ELG_NPRM_03_07_2023_1.pdf.

[69] NPDES Permit Program Fact Sheet. Available at https://edocpub.epa.ohio.gov /publicportal/ViewDocument.aspx?docid=2203468; Ohio Environmental Protection Agency, Modification of NPDES Permit. January 19, 2023. Available at https://edocpub.epa.ohio.gov/publicportal/ViewDocument.aspx?docid=2203469.

Q Why is it concerning that I&M has provided no evidence to justify incurring the CCR and ELG costs?

A With high-cost power plants like the OVEC units, utilities will generally consider retiring the plants rather than incurring additional capital investments to keep the plants online. This is especially true when a plant's utilization is projected to fall significantly.

But in this case, I&M is simply proposing to charge its customers for the cost of ELG and CCR compliance at OVEC without having presented any evidence that customers benefit from continued operation of these plants. At best, this is unreasonable resource planning. At worst, it is I&M and OVEC taking advantage of what they know is a challenging oversight environment for the OVEC plants.

vi. <u>The Commission should caution I&M that it may disallow recovery of purchases under the OVEC ICPA at above-market costs, and it should continue to cap I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA in future dockets</u>

Q Has the Commission ordered I&M to undertake any efforts to reduce its power costs or renegotiate its contract with OVEC?

A Yes. In Case U-20529, the Commission stated in its final order that "it will expect to see evidence that the Company has taken steps to minimize the cost of [power], including efforts to renegotiate contracts…"[70] In the subsequent PSCR case, Case U-20804, the Commission reiterated this directive for I&M to seek to renegotiate the contracts. The Commission also issued a Section 7 warning, notifying I&M in

[70] Commission Order dated May 13, 2021, in Case U-20529, Pg. 18.

this docket that "the Commission is unlikely to permit the utility to recover these uneconomic costs from its customers in rates, rate schedules, or PSCR factors established in the future without good faith efforts to manage existing contracts such as meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers."[71] In Case No. U-21052, the Commission stated in its final order that I&M should "uphold its obligations to assess its existing contracts as market conditions or other factors change over time and to pursue amendments or new contractual agreements that may include taking meaningful steps to renegotiate provisions of the ICPA."[72] The Commission issued a Section 7 warning in that case.[73]

Q Did I&M undertake any efforts to minimize the cost of OVEC power, including attempting to renegotiate the ICPA contract?

A Only minimally. I&M President and COO Steven F. Baker sent a letter to OVEC in January 2022 outlining the Commission orders listed above and "requesting that OVEC commence renegotiation discussions with I&M in a manner to reduce costs for I&M."[74] OVEC responded that I&M would need to obtain consent from every other sponsoring Company to modify the ICPA. OVEC also indicated that that it would need FERC approval, regulatory approval by state utility commissions, and advance consent from counterparties to OVEC's debt arrangements to modify the contract.[75]

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[71] Commission Order dated November 18, 2021, in Case U-20804, Pg. 20.
[72] Commission Order dated June 22, 2023, in Case U-21052, Pg. 20.
[73] *Id.,* Pg. 21.
[74] Case U-21052, I&M Response to Sierra Club 7-3, Attachment 1.
[75] Case U-21052, I&M Response to Sierra Club 7-3, Attachment 1.

I&M indicated that in September 2023 Mr. Baker sent another letter to OVEC to engage other Sponsoring Companies in renegotiation discussions, and "take all possible steps to reduce costs under the ICPA."[76] And subsequently in January 2024 the Company sent another letter to the OVEC Board of Directors indicating its intention to sell the portion of the ICPA associated with the Michigan jurisdiction. I&M indicated that it received no correspondence from the Board or any sponsoring Companies.[77] Finally, in July 2024, I&M spoke at the OVEC Board Meeting offering its shares of OVEC to any interested party.[78]

Company Witness Johnston indicated that I&M is currently considering options for its Indiana jurisdiction to assume its Michigan share of the OVEC energy and capacity along with all associated costs.[79]

Q Are you recommending that the Commission tell I&M how it should be operating the OVEC plants?

A No. I&M has made clear in multiple cases that it does not have the authority to unilaterally change how the OVEC units are operated and therefore has limited power over plant operations. Specifically, Company witnesses have previously stated that while the Company can provide input into the procedures OVEC follows to operate the units, "I&M is one vote of the many needed to effectuate management or operational decisions because I&M cannot unilaterally force OVEC to do anything."[80]

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[76] Case No. U-21262, Direct Testimony of Jason Stegall, Pg. 15.

[77] Case No. U-21262, Direct Testimony of Jason Stegall, Pg. 15.

[78] Direct Testimony of Witness Johnston, Pg. 8.

[79] *Id*.

[80] Case No. U-20805, Direct Testimony of Witness Stegall, Pg. 5.

While this might be true, it does not mean that I&M is totally powerless, and it does not give I&M the right to pass on to ratepayers any and all costs incurred to operate and manage the OVEC plants. The Commission agreed with this sentiment in a prior order. Specifically, in the final order in Case U-20530, the 2020 Reconciliation docket, the Commission stated, "I&M, of course, remains free to continue to make whatever business decisions it wishes in terms of continuing to participate in the ICPA. What it cannot do is continue to recover the costs of any unreasonable and imprudent decisions from its customers."[81]

Q What do you recommend regarding I&M's forecasting of future costs incurred under the ICPA in its PSCR plan?

A The Commission should caution I&M that it may disallow recovery associated with continuing to purchase power under the ICPA at above-market prices. I&M should instead only be allowed to include in the PSCR plan costs incurred under the ICPA up to the market-equivalent value of the power, as determined by the value of energy, ancillary services, and market prices for capacity.

Q What do you recommend to the Commission regarding I&M's recovery of ICPA contract costs above market prices in future reconciliation dockets?

A The Commission should once again issue a Section 7 warning to I&M that on the basis of present evidence it will once again disallow I&M's recovery of the Michigan jurisdictional share of compensation above market value for the ICPA during the PSCR period of 2025–2029.

[81] Commission Order dated February 2, 2023, in Case U-20530, Pgs. 12–13.

4. <u>I&M Is Imprudently Operating the Rockport Units, Leading to Excess Costs to its Ratepayers</u>

i. I&M is responsible for 100 percent of the cost to operate Rockport Unit 1 beginning in 2023

Q Provide an overview of the Rockport Generating Station.

A The Rockport Generating Station is a two-unit coal-fired power station located in Spencer County, Indiana. I&M operates the plant. Unit 1 has a nameplate capacity of 1,320 MW and is owned 50 percent by I&M and 50 percent by AEG. Unit 2 was previously owned by non-affiliated parties and leased back to I&M and AEG. This lease expired in December 2022.[82] Since that time, Rockport Unit 2 has been operated as a merchant facility and all related costs are excluded from this reconciliation docket.

AEG currently sells 100 percent of its share of Rockport Unit 1 back to I&M.[83]

Q How often was Rockport used in 2024?

A The Rockport units operated at a 25.43 percent capacity factor in 2024.[84]

Q What portion of Rockport's costs is I&M responsible for and how are those costs passed on to its ratepayers?

A I&M is responsible for 100 percent of the costs associated with Rockport Unit 1.

[82] Direct Testimony of Hazel Baker at 8.
[83] *Ibid*.
[84] I&M Response to AG Request 1-08, Attachment 1; I&M Response to AG Request 1-04, Attachment 1.

For the 50 percent share of Rockport Unit 1 that it owns, I&M plans for and recovers the associated fuel and consumable costs in PSCR dockets. These costs are passed on directly to customers as fuel costs through fuel clauses and are reconciled in the current docket. The remaining (non-fuel) unit costs are passed on to ratepayers through rate cases and other dockets.

For the 50 percent share of Rockport Unit 1 that AEG owns, I&M pays for the power through the Unit Power Agreement ("UPA"). Because this power is procured through a PPA, instead of from a unit operated by I&M, the entire cost of this share is passed on directly to customers through fuel clauses (not just the fuel costs). That means the entire PPA cost is forecasted and planned for in this PSCR docket.

ii. I&M's latest fuel cost plan and five-year forecast indicate that it intends to continue its uneconomic operation and commitment practices at the Rockport units

Q How does I&M model the operation of the Rockport units for the purposes of its PSCR plan?

A For the purposes of making its PSCR plan, I&M models the Rockport units as committed and dispatched economically into the market and operating only when market revenue exceeds unit costs.[85]

[85] Direct Testimony of Company Witness Baker at 13.

Q How expensive is power from Rockport projected to be on a forward-going basis?

A I&M projects that Rockport power will cost between $55.57/MWh and $64.72/MWh on a forward-going basis (Table 6).[86] This is much cheaper than I&M projected last year due in large part to I&M's projection in the current PSCR plan that Rockport's capacity factor will increase significantly. I&M's projected costs for Rockport are also much lower than I&M has experienced historically in recent years. Adding to the cost, the Company currently has more committed tons of coal than what is called for in its coal forecast.[87] I&M made a buy-out payment to a supplier to reduce the quantity of coal it received. Specifically, after deferring a portion of its 2023 coal supply to 2024, I&M decided that the best option was to eliminate a portion of its obligation that was no longer needed due to the change in consumption at Rockport. The supplier removed 1.2 million tons from the 2024 obligation at a cost of $2.00 per ton.[88] I&M incurred this cost in 2024 and does not include it in the plan period.[89]

[86] Exhibit IM-16 (SAS-3); Exhibit IM-14 (SAS-4).

[87] Direct Testimony of Hazel Baker, page 21; Direct Testimony of Darryl Scott.

[88] Direct Testimony of Company Witness Chilcote, pages 8-9.

[89] Ex. AG-17, I&M Response to AG Request 1-21.

Table 6. Total power cost for Rockport 1 in current and prior PSCR dockets

Year	Actual historical PSCR costs	I&M Projected Rockport Power Costs 2024–2028 2024 PSCR Plan ($/MWh)	I&M Projected Rockport Power Costs 2025–2029 2025 PSCR Plan ($/MWh)
2017	$58.56		
2018	$57.15		
2019	$75.35		
2020	$122.24		
2021	$128.31		
2022	$110.90		
2023	$153.66		
2024	$85.12	$121.01	
2025		$121.55	$60.35
2026		$142.76	$64.72
2027		$152.07	$55.57
2028		$208.60	$60.35
2029			

Source: Case No U-20070, Exhibit IM-4 (DLH-1); Case No U- 20204, Exhibit IM-3 (DHL-1); Case No U-20224, Exhibit IM-3 (DLH-1); Case No U-20530, Exhibit IM-4 (JEW-1); Case No U-20805, Exhibit IM-4 (JEW-1); Case No U-21053, Exhibit IM-4 (DLW-1); Case No. U-21262, Exhibit IM-3 (DLW-1); Exhibit IM-16 (SAS-3); Exhibit IM-17 (SAS-4); Casse U-21427, Direct Testimony of Devi Glick at 44.

Q Is Rockport 1 projected to operate economically on a forward-going basis?

A In the current PSCR plan, it is. This is in contrast with the Company's projections in all other recent plans. As shown in CONFIDENTIAL Figure 5, I&M's current projections show that Rockport Unit 1 will earn $53.7 million in market revenues over the next four years or $17.3 million per year (the plant is scheduled to retire in 2028 so no projections are available for 2029). This is in marked contrast with the Company's projections from last year that the unit would incur $466.3 million (present value) in excess costs relative to the market value of energy and capacity based on unit cost data over the next five years, or an average of $112.5 million per year.[90] This works out to $6.7 million over the PSCR period, or $2.1 million per year for the Michigan jurisdictional share of Rockport Unit 1.

CONFIDENTIAL Figure 5. Rockport 1 projected net revenues, 2025–2029 [[

[redacted]

]] *Source: I&M Response to Attorney General Request 1-11, CONFIDENTIAL Attachment 1; Workpapers for Exhibits 14-17, Tab "Line 14"; I&M Response to Attorney General Request 1-04, Attachment 1; I&M Response to Attorney General Request 1-09, Attachment 3; I&M Response to Attorney General Request 1-09, CONFIDENTIAL Attachment 4.*

Q How did you calculate these values?

A The Company provided projected generation[91] and a breakdown of fuel and demand expenses associated with AEG's portion of Rockport 1 over the next five years. I assumed that the fuel expenses[92] represented Rockport's variable costs and

[90] Docket U-21427, Direct Testimony of Devi Glick at 44.

[91] I&M Response to Attorney General, Request 1-11, CONFIDENTIAL Attachment 1.

[92] Workpapers for Exhibits 14-17, Tab "Line 14."

the demand expenses[93] represented Rockport's fixed costs. I scaled these values up to represent I&M's total share in Rockport (the AEG PPA represented 50 percent of I&M's 100-percent share of Rockport Unit 1). I summed the fuel and demand expenses to get total forward-going costs for the unit. I calculated capacity revenue using the ICAP values[94] I&M provided and the capacity price forecast from I&M's capacity market forecast.[95] I added that to energy market revenue, which I calculated based on I&M's power market prices.[96] I compared total costs to total revenues to find the net revenues.

Q Why does I&M project Rockport's utilization will increase so much relative to its projections last year?

A As discussed in Section 3 above, I&M is relying on a high energy market forecast over the PSCR plan. Higher energy market revenues will make Rockport operate more relative to a lower forecast that the Company used in prior years. As shown in Figure 6 below, this has resulted in a large jump in I&M's projections for the unit's use. The Company does not explain the jump beyond attributing it to the PLEXOS model's response to higher market prices. Given the substantial deviation between this year's PSCR plan forecast and the unit's prior year forecasts, and historical performance, I am concerned that I&M is substantially overestimating the unit's performance.

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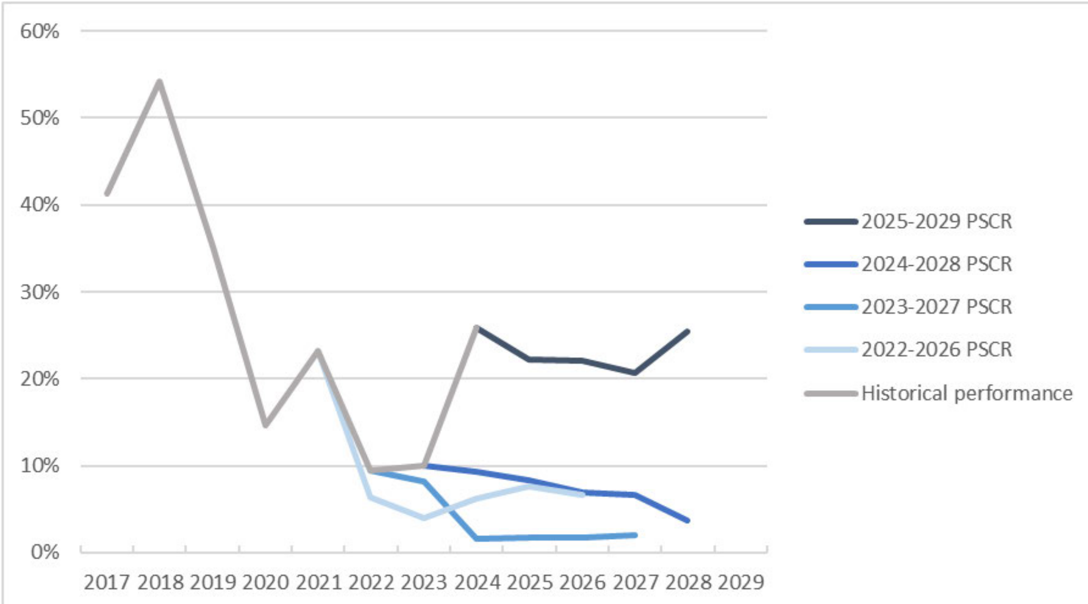
[93] *Ibid.*

[94] I&M Response to Attorney General Request 1-04, Attachment 1.

[95] I&M Response to Attorney General Request 1-09, Attachment 3.

[96] I&M Response to Attorney General Request 1-09, CONFIDENTIAL Attachment 4.

Figure 6. Rockport capacity factor projections



Source: Case No. U-21052, Exhibit IM-9 (HAB); Case No. U-21261, Exhibit IM-8 (HAB); Case No. U-21427, Exhibit IM-9 (HAB); Exhibit IM-9 (HAB-9).

Q What do you recommend regarding I&M's forecasting of future costs incurred at Rockport 1 and included in its PSCR plan?

A The Commission should only approve I&M's PSCR plan to the extent it is developed around assumptions that Rockport 1 is operated economically (i.e., using an economic commitment status) and that the modeled assumptions are consistent with how the Company actually operates Rockport 1. In other words, I&M should plan to operate its power plants efficiently and should not plan to run Rockport when cheaper energy is available from the PJM market. The Commission should signal to I&M that in future reconciliation dockets it will disallow costs incurred at Rockport 1 as a result of uneconomic commitment practices.

Q **Does this conclude your testimony?**

A Yes.

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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

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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.

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 (Case No. U-20223) for the 12-month period ending December 31, 2019. On behalf of Sierra Club. October 23, 2020.

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.

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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.

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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.

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 August 2021

ANNUAL REPORT — 2023

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 under a Department of Energy (DOE) Power Agreement. On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc.[1]	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Ohio Edison Company[1]	0.85
Ohio Power Company**[6]	4.30
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
The Toledo Edison Company[1]	4.00
	100.00

The Sponsoring Companies are each either a shareholder in the Company or an affiliate of a shareholder in the Company, with the exception of Vistra Vision. The Sponsoring Companies currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC[1]	3.01
Appalachian Power Company[6]	15.69
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Indiana Michigan Power Company[6]	7.85
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Monongahela Power Company[1]	0.49
Ohio Power Company[6]	19.93
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
Vistra Vision	4.85
	100.00

Some of the Common Stock issued in the name of:

*American Gas & Electric Company
**Columbus and Southern Ohio Electric Company

Subsidiary or affiliate of:
[1]FirstEnergy Corp.
[2]Buckeye Power, Inc.
[3]The AES Corporation
[4]Duke Energy Corporation
[5]PPL Corporation
[6]American Electric Power Company, Inc.
[7]Wolverine Power Supply Cooperative, Inc.
[8]CenterPoint Energy, Inc.

A Message from the President

In 2023, Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), provided valuable services when called upon, took significant steps toward zero harm, and culturally focused on improving ourselves and our equipment. Even though the PJM Market experienced a significant decline in power demand, due to oversupply of natural gas at reduced prices and milder-than-expected weather, the critical need for dispatchable generation during peak demand periods was highlighted by winter storms that impacted various parts of North America. Recognizing this vital role to support the grid, the OVEC-IKEC team is focused on preparing our units for the next positive market shift or any future grid event.

As we move into 2024, OVEC-IKEC remains committed to delivering value to our Sponsors. The ongoing nationwide retirement of baseload facilities creates an increasingly urgent need for reliable power sources. This trend, coupled with the anticipated surge in data center load demand over the next five to ten years, presents a strong need for dispatchable power. OVEC-IKEC's critical generation can be instrumental in meeting these evolving needs.

Even with drastically changing markets, the OVEC-IKEC team continues to work hard on creating a zero-harm culture, focusing on environmental stewardship, and improving our cost and operations with continuous improvement and LEAN tools to meet our Sponsor's needs.

SAFETY

OVEC-IKEC continues to achieve new accomplishments in Safety as System Office employees, including Electrical Operations, completed 9 years in April with no recordable injuries; and on May 11, they also reached a milestone of 18 years without a lost-time injury. In February 2024, Kyger Creek employees completed 1 year without a recordable injury. Finally, through May 2024, only one recordable injury has occurred companywide, which is the best corporate safety result in OVEC-IKEC's history.

In alignment with OVEC's 2024 Strategic Plan Zero Harm and Continuous Improvement Objectives, OVEC uses proactive measures to promote safety throughout the organization. In support of this, the identification and tracking of hazard recognitions and close calls has been implemented. The hazard recognitions and close call submissions are a combined effort of Company employees and our strategic partners and as a result through May 2024 over 600 submissions have been recorded.

CULTURE

OVEC-IKEC remains on its continuous journey of culture improvement. Beginning in 2016, the Company has seen significant improvement from the initial survey and continues to make improvements every year. OVEC-IKEC believes investing in culture improvement to engage our people will be the key to our long-term success. For 2024, we will continue with another survey to allow our teams to continue to focus on opportunities and update their culture action plans to enable improvement.

RELIABILITY

In 2023, the combined equivalent availability of the five generating units at Kyger Creek and the six units at Clifty Creek was 75.2 percent compared with 66.3 percent in 2022. The combined equivalent forced outage rate (EFOR) at both plants was 5.7 percent in 2023 compared with 11.0 percent in 2022.

Through May 2024, the combined EFOR of the eleven generating units was 4.1 percent.

ENERGY SALES

OVEC's use factor — the ratio of power scheduled by the Sponsoring Companies to power available — for the combined on- and off-peak periods averaged 69.1 percent in 2023 compared with 90.5 percent in 2022. The on-peak use factor averaged 72.6 percent in 2023 compared with 92.6 percent in 2022. The off-peak use factor averaged 64.8 percent in 2023 and 87.7 percent in 2022.

In 2023, OVEC delivered 9.6 million megawatt hours (MWh) to the Sponsoring Companies under the terms of the Inter-Company Power Agreement compared with 11.0 million MWh delivered in 2022. During 2022, both generation and utilization were impacted by record high energy demand combined with high natural gas prices and reduced baseload generation in the region. By contrast, 2023 saw weaker natural gas prices and milder weather, resulting in lower demand.

POWER COSTS

In 2023, OVEC's average power cost to the Sponsoring Companies was $80.81 per MWh compared with $69.21 per MWh in 2022. The average power cost increase for 2023 was a result of weaker demand caused by low energy prices related to natural gas oversupply.

2022 ENERGY SALES OUTLOOK

Weakened demand from the oversupply of natural gas and lower prices continues to impact OVEC's generation in 2024. OVEC's use factor is up slightly, as May YTD was 76.4% compared to 71.2% May YTD 2023. OVEC's updated projection for 2024, which assumes some continued weaker than expected energy demand through the end of the year, is projected at approximately 10.6 million MWh of generation.

COST CONTROL INITIATIVES

The OVEC and IKEC employees continue to strive to control costs and improve operating performance through application of its continuous improvement process (CIP). Over $28 million in sustainable savings has been obtained through the implementation of more than 9,000 process improvements since 2013. Employee-driven process improvements and a continued effort in hands-on skill development with CIP and LEAN tools throughout the Company are driving the sustainability of the continuous improvement efforts.

In 2023, OVEC-IKEC continued utilizing the LEAN tool of Open Book Leadership (OBL) as a cost-control initiative to further improve our culture and overall business success. The OBL process creates transparency in Company performance and engages employees in their ability to impact and improve key performance areas.

OVEC-IKEC has utilized third-party support to challenge the team to identify additional key areas across the Company. Business cases and metrics have been developed and cost savings and revenue opportunities are currently being tracked and realized.

ENVIRONMENTAL COMPLIANCE

OVEC-IKEC continues to maintain a strong commitment to meeting all applicable federal, state and local environmental rules and regulations. During 2023, OVEC operated in substantial compliance with the Mercury Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSAPR) and other applicable state and federal air, water and solid waste regulations. In addition, for the seventh consecutive year, OVEC successfully met the challenge of operating in compliance with ozone season NOx constraints that initially went into effect with the 2017 ozone season with the adoption of USEPA's CSAPR Update Rule. The Company is well positioned to continue to operate all SCR controlled units during 2024.

Clifty Creek and Kyger Creek both continue to sell the majority of the gypsum produced at each plant into the wallboard market. Clifty Creek has also been successful in marketing fly ash, and OVEC anticipates that market will continue to grow longer term. Kyger Creek completed its dry ash conversion project in late 2022.

Significant heavy construction activities at both plant facilities were completed in 2023 as the Company executed its CCR Rule Part A compliance strategy.

Separately, the Company has taken steps to implement its compliance strategy to meet the requirements of the final revised steam electric effluent limitation guideline (ELG) regulations published in 2020, applicable to certain wastewater discharges from Clifty Creek and Kyger Creek operations. The Company has met the initial applicability dates for bottom ash transport water and expects to meet the applicability dates for FGD wastewaters in accordance with each plant's NPDES permits.

On June 30, 2022, the U.S. Supreme Court issued a decision reversing the D.C. Circuit Court's decision to vacate the Affordable Clean Energy (ACE) Rule. Since that time, the USEPA proposed new draft rules that would repeal the ACE rule and issue new greenhouse gas reduction requirements, which are expected to be finalized in mid-2024. OVEC will continue monitoring regulatory and legislative initiatives that may impact the utility sector carbon emissions as well as any other regulatory and legislative initiatives.

In the interim, the Company continues to work toward executing its compliance strategies for complying with obligations associated with the 2015 CCR rule, the 2020 ELG Rules, and the Clean Water Act Section 316(b) regulations applicable to both facilities.

BOARD OF DIRECTORS AND OFFICERS CHANGES

On October 13, 2023, Mr. Brian D. Sherrick, Vice President, Generation Shared Services, American Electric Power Service Corporation, was elected a director of OVEC and IKEC and appointed to the Executive Committees of both Companies. Mr. Sherrick was also elected to serve as president of OVEC and IKEC. He succeeded Mr. Paul Chodak III, who had served on the OVEC and IKEC boards and Executive Committees since 2019. Mr. Chodak also served as president of OVEC and IKEC since 2019.

On December 18, 2023, Ms. Heather Watts, Vice President, Associate General Counsel Regulatory Legal, CenterPoint Energy, was elected a member of the OVEC and IKEC boards. Ms. Watts replaced Mr. Wayne D. Games who resigned effective May 5, 2023.

On March 21, 2024, Mr. Thomas A. Raga, Vice President, AES US Utilities, was elected a member of the OVEC board. Mr. Raga replaced Mr. Ahmed Pasha who resigned effective January 1, 2024.

On March 21, 2024, Mr. Olenger L. Pannell, Vice President, Compliance & Regulated Services and Chief FERC Compliance Officer, First Energy, was elected a member of the OVEC and IKEC boards. Mr. Pannell replaced Mr. David Pinter who resigned effective December 31, 2023.

Brian D. Sherrick
OVEC-IKEC President

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2023 AND 2022

	2023	2022
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 3,181,000,415	$ 2,951,082,964
Less—accumulated provisions for depreciation	2,145,475,614	1,899,379,433
	1,035,524,801	1,051,703,531
Construction in progress	17,869,041	99,942,979
Total electric plant	1,053,393,842	1,151,646,510
CURRENT ASSETS:		
Cash and cash equivalents	39,734,708	50,612,220
Accounts receivable	65,061,157	50,711,358
Fuel in storage	165,654,233	62,374,566
Materials and supplies	57,450,329	46,784,231
Property taxes applicable to future years	3,762,000	3,162,000
Regulatory assets	1,643,440	1,644,000
Prepaid expenses and other	4,655,934	6,394,911
Total current assets	337,961,801	221,683,286
REGULATORY ASSETS:		
Unrecognized postemployment benefits	8,808,588	10,567,071
Unrecognized pension benefits	2,178,707	9,210,770
Income taxes billable to customers	33,721,522	12,938,237
Other regulatory assets	4,415,307	6,058,187
Total regulatory assets	49,124,124	38,774,265
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	747,151	406,653
Long-term investments	191,373,359	277,080,718
Postretirement benefits	46,589,903	29,096,447
Other	2,865,000	2,866,535
Total deferred charges and other	241,575,413	309,450,353
TOTAL	$ 1,682,055,180	$ 1,721,554,414

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2023 AND 2022

CAPITALIZATION AND LIABILITIES	2023	2022
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2023 and 2022	$ 10,000,000	$ 10,000,000
Long-term debt	814,322,489	911,772,190
Line of credit borrowings	140,000,000	110,000,000
Retained earnings	28,429,819	25,501,978
Total capitalization	992,752,308	1,057,274,168
CURRENT LIABILITIES:		
Current portion of long-term debt	98,831,592	69,523,395
Current portion of line of credit borrowings	10,000,000	-
Accounts payable	70,075,957	85,520,164
Accrued other taxes	17,040,414	10,925,537
Regulatory liabilities	847,054	72,118,927
Asset retirement obligations	19,724,090	-
Accrued interest and other	21,522,096	21,852,765
Total current liabilities	238,041,203	259,940,788
COMMITMENTS AND CONTINGENCIES (Notes 3, 9, 11, and 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	137,206,331	115,060,018
Advance billing of debt reserve	120,000,000	120,000,000
Total regulatory liabilities	257,206,331	235,060,018
OTHER LIABILITIES:		
Pension liability	2,178,707	9,210,770
Deferred income tax liability	22,206,478	15,267,530
Asset retirement obligations	159,350,630	131,942,458
Postretirement benefits obligation	-	528,669
Postemployment benefits obligation	8,808,588	10,567,071
Other non-current liabilities	1,510,935	1,762,942
Total other liabilities	194,055,338	169,279,440
TOTAL	$1,682,055,180	$1,721,554,414

See notes to consolidated financial statements.

(Concluded)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS AS OF DECEMBER 31, 2023 AND 2022

	2023	2022
REVENUES FROM CONTRACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 4,126,832	$ 9,068,557
Ohio Valley Electric Corporation	-	-
Sponsoring Companies	850,874,742	752,430,431
Total revenues from contracts with customers	855,001,574	761,498,988
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	344,622,250	354,335,638
Purchased power	3,937,749	10,853,154
Other operation	88,025,177	85,527,745
Maintenance	92,064,829	87,282,316
Depreciation	256,096,220	152,943,176
Federal income tax	3,000,000	-
Taxes—other than income taxes	12,417,841	12,077,825
Total operating expenses	800,164,066	703,019,854
OPERATING INCOME	54,837,508	58,479,134
OTHER INCOME (EXPENSE)	197,576	(28,436)
INCOME BEFORE INTEREST CHARGES	55,035,084	58,450,698
INTEREST CHARGES:		
Amortization of debt expense	1,730,851	3,704,984
Interest expense	50,376,392	52,044,722
Total interest charges	52,107,243	55,749,706
NET INCOME	2,927,841	2,700,992
RETAINED EARNINGS—Beginning of year	25,501,978	22,800,986
RETAINED EARNINGS—End of year	$ 28,429,819	$ 25,501,978

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
AS OF DECEMBER 31, 2023 AND 2022

	2023	2022
OPERATING ACTIVITIES:		
Net income	$ 2,927,841	$ 2,700,992
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	256,096,220	152,943,176
Amortization of debt expense	1,730,851	3,704,984
Changes in assets and liabilities:		
Accounts receivable	(14,349,799)	(14,421,892)
Fuel in storage	(103,279,667)	(22,021,893)
Materials and supplies	(10,666,098)	(3,137,732)
Property taxes applicable to future years	(600,000)	(45,300)
Emissions allowances	-	81,833
Prepaid expenses and other	1,738,977	(1,964,405)
Other regulatory assets	(3,250,410)	(4,837,520)
Other noncurrent assets	(17,491,921)	(12,937,493)
Accounts payable	(14,541,030)	38,396,151
Accrued taxes	6,114,877	(6,520,997)
Accrued interest and other	691,245	404,812
Other liabilities	(74,186,215)	(64,451,051)
Other regulatory liabilities	(45,321,625)	44,820,112
Net cash (used in) provided by operating activities	(14,386,754)	112,713,777
INVESTING ACTIVITIES:		
Changes in short-term intercompany lendings	-	-
Electric plant additions	(50,822,921)	(88,297,756)
Proceeds from sale of long-term investments	933,946,766	807,332,153
Purchases of long-term investments	(848,379,837)	(802,319,245)
Net cash (used in) provided by investing activities	34,744,008	(83,284,848)
FINANCING ACTIVITIES:		
Changes in short-term intercompany borrowings	-	-
Debt issuance and maintenance costs	(689,458)	(2,103,018)
Repayment of Senior 2006 Notes	(27,726,072)	(26,176,986)
Repayment of Senior 2007 Notes	(19,773,778)	(18,650,218)
Repayment of Senior 2008 Notes	(22,023,544)	(20,640,593)
Repayment of Senior 2017A Notes	-	(66,666,667)
Proceeds from line of credit	40,000,000	100,000,000
Principal payments under finance leases	(1,021,914)	(946,103)
Net cash (used in) provided by financing activities	(31,234,766)	(35,183,585)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(10,877,512)	(5,754,656)
CASH AND CASH EQUIVALENTS—Beginning of year	50,612,220	56,366,876
CASH AND CASH EQUIVALENTS—End of year	$ 39,734,708	$ 50,612,220
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 52,107,243	$ 51,172,106
Income taxes (received) paid—net	$ 9,700,000	$ 8,100,000
Non-cash electric plant additions included in accounts payable at December 31	$ 136,855	$ 903,177

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements—The consolidated financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization—The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement ("ICPA"), which has a current termination date of June 30, 2040. Approximately 22% of the Companies' employees are covered by a collective bargaining agreement that expires on August 31, 2024.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy ("DOE"). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power ("Arranged Power"), under the direction of the DOE, for resale directly to the DOE. The current agreement with the DOE was executed on July 11, 2018, for one year, with the option for the DOE to extend the agreement at the anniversary date. The agreement was extended on July 11, 2023, for one year. OVEC anticipates that this agreement could continue to 2027.All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from the sale of power are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost-plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred in the accompanying consolidated balance sheets and are recognized as income as the related amounts are included in service rates and recovered from or refunded to customers.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through the billings of the Sponsoring Companies at December 31, 2023 and 2022, were as follows:

	2023	2022
Regulatory assets:		
Current regulatory assets:		
Other regulatory assets	$ 1,643,440	$ 1,644,000
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	8,808,588	10,567,071
Unrecognized pension benefits	2,178,707	9,210,770
Income taxes billable to customers	33,721,522	12,938,237
Other regulatory assets	4,415,307	6,058,187
Total	49,124,124	38,774,265
Total regulatory assets	$ 50,767,564	$ 40,418,265
Regulatory liabilities:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ -	$ 70,190,903
Deferred credit—advance collection of interest	847,054	1,928,024
Total	847,054	72,118,927
Noncurrent regulatory liabilities:		
Postretirement benefits	137,206,331	115,060,018
Advance billing of debt reserve	120,000,000	120,000,000
Total	257,206,331	235,060,018
Total regulatory liabilities	$ 258,053,385	$ 307,178,945

Regulatory Assets—Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs, and income taxes to be billed to the Sponsoring Companies in future years. The Companies' current billing policy for pension and postemployment benefit costs is to bill its actual plan funding.

Regulatory Liabilities— The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2023, consist primarily of interest expense collected from customers in advance of expense recognition. These amounts will be credited to customer bills during 2024. Other regulatory liabilities consist primarily of postretirement benefit costs and advanced billings collected from the Sponsoring Companies for debt service.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

The regulatory liability for postretirement benefits recorded at December 31, 2023 and 2022, represents amounts collected in historical billings in excess of net periodic benefit costs recognizable under accounting principles generally accepted in the United States of America ("GAAP"), including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental net plan assets recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs.

Beginning January 2017 and continuing through December 31, 2020, the Companies billed the Sponsoring Companies for debt service as allowed under the ICPA. A total of $120 million was billed during this period. As the Companies have not yet incurred the related costs, a regulatory liability was recorded which will be credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant— Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service, if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue—advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies— The Companies maintain coal, reagent, and oil inventories for use in the generation of electricity. Additionally, the Companies maintain emission allowance inventories for regulatory compliance purposes. These inventories are valued at average cost. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments— Long-term investments consist of marketable securities and other investments that are held for the purpose of funding decommissioning and demolition costs, debt service, potential postretirement funding, and other costs. These debt securities have been classified as trading securities in accordance with Accounting Standards Codification ("ASC") Topics 320 and 321. Debt and equity securities reflected in long-term investments are carried at fair value. The cost of securities sold is based on the specific identification cost method. The fair value of investment securities is determined by reference to quoted market prices when available. Where quoted market prices are not available, the Companies use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Long-term investments, primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2023 and 2022 on securities still held at the balance sheet date were $1,725,732 and $(14,659,334), respectively.

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Fair Value Measurements of Assets and Liabilities— The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense— Unamortized debt expense relates to costs incurred in connection with obtaining revolving credit agreements. These costs are amortized over the term of the related revolving credit agreement and are recorded as an asset in the consolidated balance sheets. Costs incurred to issue debt are recorded as a reduction to long-term debt as presented in Note 6, Long-Term Debt.

Asset Retirement Obligations and Asset Retirement Costs— The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time of the incurrence of the obligations when such obligations are probable and the amounts can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant), for payments in satisfaction of asset retirement obligations, and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to plant closure costs, including the impacts of the coal combustion residuals rule (“CCR”), as well as obligations associated with future asbestos abatement.

Balance—January 1, 2022	$ 159,573,299
Accretion	10,000,677
Liabilities settled	(42,163,677)
Revisions to cash flows	4,532,159
Balance—December 31, 2022	131,942,458
Accretion	12,102,012
Liabilities settled	(66,380,656)
Revisions to cash flows	101,410,906
Balance—December 31, 2023	$ 179,074,720
Current	$ 19,724,090
Non-current	159,350,630
Balance—December 31, 2023	$ 179,074,720

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In response to revised regulations for coal combustion residuals and the potential for the establishment of even more reformative rules, the Companies have accelerated the timing of remediation activities related to their coal ash ponds and landfills. This resulted in liabilities settled in 2022 and 2023, as disclosed in the table above. Changes in the regulations, or in the remediation technologies could potentially result in material increases in the asset retirement obligation. The Companies will revisit the studies, as necessary throughout the process of executing remediation related to the coal ash ponds and landfills to maintain an accurate estimated cost of remediation.

The revised cash flow estimates in 2023 and 2022 reflect the outcome of the decommissioning and demolition study resulting in an upward revision of $101.4 million and $4.5 million. This increase was primarily driven by changes in CCR compliance strategies.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated, and no amounts are recognized in the consolidated financial statements herein.

Income Taxes— The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities, which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for income taxes.

Use of Estimates— The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and to disclose contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition— Revenue is recognized when the Companies transfer promised goods or services to customers in an amount that reflects the consideration to which the Companies expect to be entitled in exchange for those goods or services. Performance obligations related to the sale of electric energy are satisfied over time as system resources are made available to customers and as energy is delivered to customers. and the Companies recognize revenue upon billing the customer.

The Companies have two contracts with customers that give rise to the following revenue types:

1) Sales of Electric Energy to The Department of Energy
2) Sales of Electric Energy to Sponsoring Companies

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The Companies have no contract assets or liabilities as of December 31, 2023. The following table provides information about the Companies' receivables from contracts with customers:

	Accounts Receivable
Beginning balance—January 1, 2022	$ 36,289,466
Ending balance—December 31, 2022	50,711,358
Increase/(decrease)	$ 14,421,892
Beginning balance—January 1, 2023	$ 50,711,358
Ending balance—December 31, 2023	65,061,157
Increase/(decrease)	$ 14,349,799

Subsequent Events— In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 19, 2024, which is the date the consolidated financial statements were issued.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2023 and 2022 included the sale of all generated power, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Buckeye Power Generating, LLC, Peninsula Generation Cooperative, Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies, as well as Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2023 and 2022, balances due from the Sponsoring Companies are as follows:

	2023	2022
Accounts receivable	$ 52,500,983	$ 42,765,234

During 2023 and 2022, American Electric Power Company, Inc., accounted for approximately 44% of operating revenues from Sponsoring Companies and Buckeye Power Generating, LLC, accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2023. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2023	**2022**
General services	$ 2,403,734	$ 3,039,684
Specific projects	98,903	539,361
Total	$ 2,502,637	$ 3,579,045

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation. Charges for these services are included in the Companies' operating expense.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2024 through 2028. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2024 coal requirements under contract. These contracts are based on rates in effect at the time of contract execution. The Companies' total obligations under these agreements as of December 31, 2023, are included in the table below:

2024	$ 322,804,000
2025	251,611,000
2026	59,614,000
2027	26,250,000
2028	26,250,000

4. ELECTRIC PLANT

Electric plant at December 31, 2023 and 2022, consists of the following:

	2023	2022
Steam production plant	$3,085,605,811	$2,855,417,793
Transmission plant	82,063,668	82,481,029
General plant	13,304,372	13,157,578
Intangible	26,564	26,564
	3,181,000,415	2,951,082,964
Less accumulated depreciation	2,145,475,614	1,899,379,433
	1,035,524,801	1,051,703,531
Construction in progress	17,869,041	99,942,979
Total electric plant	$1,053,393,842	$1,151,646,510

All property additions and replacements are fully depreciated on the date the property is placed in service unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the debt service schedule under the debt agreements, all financed projects are depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC has a revolving credit facility of $150 million which was renewed on March 16, 2023, and set to expire on March 16, 2026. At December 31, 2023 and 2022, OVEC had borrowed $140 million and $110 million, respectively, under the revolving credit facility. Additionally, OVEC has a 364-day revolving credit facility of $35 million entered into on December 19, 2023. As of December 31, 2023, OVEC had borrowed $10 million under the 364-day revolving credit facility. Interest expense related to lines of credit borrowings was $9,022,080 in 2023 and $1,952,656 in 2022. During 2023 and 2022, OVEC incurred annual commitment fees of $76,542 and $393,861, respectively, based on the borrowing limits of the line of credit.

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6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2023 and 2022:

	Interest Rate Type	Interest Rate	2023	2022
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 72,333,829	$ 98,493,793
2006B due June 15, 2040	Fixed	6.40	48,429,148	49,995,256
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	29,295,163	41,630,472
2007A-B due February 15, 2026	Fixed	5.90	7,377,699	10,484,226
2007A-C due February 15, 2026	Fixed	5.90	7,436,445	10,567,708
2007B-A due June 15, 2040	Fixed	6.50	24,107,521	24,904,952
2007B-B due June 15, 2040	Fixed	6.50	6,071,242	6,272,067
2007B-C due June 15, 2040	Fixed	6.50	6,119,584	6,322,007
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	9,148,464	12,999,705
2008B due February 15, 2026	Fixed	6.71	18,138,280	26,166,048
2008C due February 15, 2026	Fixed	6.71	20,614,382	28,529,215
2008D due June 15, 2040	Fixed	6.91	35,382,998	36,488,446
2008E due June 15, 2040	Fixed	6.91	35,997,799	37,122,454
Series 2009 Bonds:				
2009A due February 1, 2026	Fixed	2.88	25,000,000	25,000,000
2009B due February 1, 2026	Fixed	1.38	25,000,000	25,000,000
2009C due February 1, 2026	Fixed	1.50	25,000,000	25,000,000
2009D due February 1, 2026	Fixed	2.88	25,000,000	25,000,000
Series 2010 Bonds:				
2010A due November 1, 2030	Fixed	3.00	50,000,000	50,000,000
2010B due November 1, 2030	Fixed	2.50	50,000,000	50,000,000
Series 2012 Bonds:				
2012A due November 1, 2030	Fixed	4.25	200,000,000	200,000,000
2012B due November 1, 2030	Fixed	3.00	50,000,000	50,000,000
2012C due November 1, 2030	Fixed	3.00	50,000,000	50,000,000
Series 2019 Bonds—				
2019A due September 1, 2029	Fixed	3.25	100,000,000	100,000,000
Total debt			920,452,554	989,976,349
Less unamortized debt expense			(7,298,473)	(8,680,764)
Total debt net of premiums, discounts, and unamortized debt expense			913,154,081	981,295,585
Current portion of long-term debt			98,831,592	69,523,395
Total long-term debt			$814,322,489	$911,772,190

Since 2009, OVEC has entered into a number of tax-exempt financing arrangements. Under these arrangements, the Ohio Air Quality Development Authority ("OAQDA"), and the Indiana Finance Authority ("IFA") issued tax exempt bonds, and the Companies entered back-to-back loan agreements under which the Companies are obligated to make payments equal to the principal and interest due on such bonds.

The 2009, 2010, 2012B and 2012C Bonds were originally issued as variable-rate remarketable put bonds backed by irrevocable transferable direct-pay letters of credit. These bonds were all subsequently remarketed as fixed-rate bonds with interest periods that extend through their final maturity dates, except for the 2009B and 2009C bonds, which have interest periods that extend through October 31, 2024 and November 3, 2025, respectively, at which point such bonds are subject to mandatory tender.

The 2010, 2012B, 2012C and 2019 Bonds are all scheduled to begin amortizing in 2026. The 2012A Bonds will begin amortizing in 2027.

Pursuant to an agreement with the lender, the remaining $66,666,667 of principal owed on the 2017 note was repaid on August 4, 2022.

Certain of OVEC's bonds and its revolving credit facility require the Companies to maintain a minimum of $11 million of equity, which includes common stock and retained earnings balances. Common stock and retained earnings approximated $38 million as of December 31, 2023.

The annual maturities of long-term debt as of December 31, 2023, are as follows:

2024	$ 98,831,592
2025	78,243,501
2026	146,286,140
2027	110,387,120
2028	117,144,631
2029–2040	369,559,570
Total	$920,452,554

Note that the 2024 maturities include $25 million variable rate bonds subject to remarketing in October 2024.

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7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2023	2022
Income tax expense at statutory rate (21%)	$ 1,244,847	$ 567,208
Temporary differences flowed through to customer bills	1,753,316	(568,333)
Permanent differences and other	1,837	1,125
Income tax provision	$ 3,000,000	$ -

Components of the income tax provision were as follows:

	2023	2022
Current income tax expense—federal	$ 16,782,327	$ 6,330,131
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	(13,782,327)	(6,330,131)
Total income tax provision	$ 3,000,000	$ -

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected charges or credits in customer billings for deferred tax assets and liabilities, they have recorded a regulatory asset or liability representing income taxes billable or refundable to customers under the applicable agreements among the parties. These temporary differences will be billed or credited to the Sponsoring Companies through future billings. The regulatory asset was $33,721,522 and $12,938,237 at December 31, 2023 and 2022, respectively.

Deferred income tax assets (liabilities) at December 31, 2023 and 2022, consisted of the following:

	2023	2022
Deferred tax assets:		
Deferred revenue—advances for construction	$ -	$ 14,741,991
Pension benefits	-	905,379
Postemployment benefit obligation	1,849,974	2,219,371
Asset retirement obligations	37,609,157	27,711,492
Advanced collection of interest and debt service	25,380,220	23,990,521
Miscellaneous accruals	1,146,109	1,087,987
Regulatory liability-postretirement benefits	28,815,985	24,165,722
Total deferred tax assets	94,801,445	94,822,463
Deferred tax liabilities:		
Prepaid expenses	(744,560)	(644,205)
Electric plant	(51,136,454)	(69,476,217)
Unrealized gain/loss on marketable securities	(317,346)	(1,542,690)
Postretirement benefits	(9,784,781)	(6,000,007)
Pension benefits	(655,532)	-
Regulatory asset—pension benefits	(457,571)	(1,934,511)
Regulatory asset—other	(1,272,454)	-
Regulatory asset—postemployment benefits	(1,849,974)	(2,219,371)
Regulatory asset—income taxes billable to customers	(7,079,145)	(2,711,388)
Total deferred tax liabilities	(73,297,817)	(84,528,389)
Valuation allowance	(43,710,106)	(25,561,604)
Deferred income tax liability	$(22,206,478)	$(15,267,530)

Because future taxable income may prove to be insufficient to recover the Companies' gross deferred tax assets, the Companies have recorded a valuation allowance for deferred tax assets as of December 31, 2023 and 2022.

The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2023 and 2022, and accordingly, no liabilities for uncertain tax positions have been recognized.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2019 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2019 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2018 and earlier.

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the "Pension Plan"), covering substantially all employees hired prior to January 1, 2015. The benefits are based on years of service and each employee's highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits ("Other Postretirement Benefits") for retired employees. Substantially all of the Companies' employees hired prior to January 1, 2015, become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established VEBA trusts. In January 2011, the Companies established an Internal Revenue Code Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts for pension benefits and postretirement life plan represent approximately a 55% and 45% split between OVEC and IKEC, respectively, as of December 31, 2023, and a 54% and 46% split between OVEC and IKEC, respectively, as of December 31, 2022. The allocated amounts for postretirement medical plan represent approximately a 53% and 47% split between OVEC and IKEC, respectively, as of December 31, 2023, and a 52% and 48% split between OVEC and IKEC, respectively, as of December 31, 2022.

The Pension Plan's assets as of December 31, 2023, consist of investments in equity and debt securities. All of the trust funds' investments for the pension and postemployment benefit plans are diversified and managed in compliance with applicable laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC-IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	**Target**
Domestic equity	15 %
International and global equity	15
Fixed income	68
Cash	2
VEBA Plan Assets	
Domestic equity	20 %
International and global equity	20
Fixed income	60

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Fixed-Income Limitations—As of December 31, 2023, the Pension Plan fixed-income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed-income allocation is composed of a variety of fixed-income securities and mutual funds. Investment limitations for these fixed-income funds are defined by manager prospectus.

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Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2023 and 2022, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2023	2022	2023	2022
Change in benefit obligation:				
Benefit obligation—beginning of year	$175,515,791	$263,593,975	$115,228,026	$165,904,272
Service cost	3,934,599	6,243,823	2,235,362	3,704,556
Interest cost	8,426,290	8,424,852	6,054,459	4,896,183
Plan participants' contributions	-	-	1,408,571	1,409,028
Benefits paid	(6,199,021)	(7,615,660)	(6,871,369)	(6,685,855)
Net actuarial loss (gain)	4,895,556	(73,927,665)	(11,022,277)	(54,000,158)
Expenses paid from assets	(232,062)	(65,543)	-	-
Settlements	(43,233,690)	(21,137,991)	-	-
Benefit obligation—end of year	143,107,463	175,515,791	107,032,772	115,228,026
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	166,305,021	244,797,390	143,795,804	172,402,647
Actual return on plan assets	17,088,508	(55,873,175)	15,265,390	(23,353,088)
Expenses paid from assets	(232,062)	(65,543)	-	-
Employer contributions	7,200,000	6,200,000	24,279	23,072
Plan participants' contributions	-	-	1,408,571	1,409,028
Benefits paid	(6,199,021)	(7,615,660)	(6,871,369)	(6,685,855)
Settlements	(43,233,690)	(21,137,991)	-	-
Fair value of plan assets—end of year	140,928,756	166,305,021	153,622,675	143,795,804
(Underfunded) Overfunded status—end of year	$ (2,178,707)	$ (9,210,770)	$ 46,589,903	$ 28,567,778

See Note 1, Organization and Significant Accounting Policies, for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits.

The accumulated benefit obligation for the Pension Plan was $126,768,473 and $159,689,081 at December 31, 2023 and 2022, respectively.

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During 2023, the Pension Plan paid lump sum payouts and purchased an annuity, the total of which exceeded the Pension Plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting in the second and fourth quarters. Settlement charges of $43.2 million and $21.1 million were recorded as of December 31, 2023 and 2022, respectively. Net periodic pension benefit cost increased by $4.5 million and $3.0 million as of December 31, 2023 and 2022, as the result of the remeasurement.

Components of Net Periodic Benefit Cost— The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under GAAP, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2023	2022	2023	2022
Service cost	$ 3,934,599	$ 6,243,823	$ 2,235,362	$ 3,704,556
Interest cost	8,426,290	8,424,852	6,054,459	4,896,183
Expected return on plan assets	(10,199,408)	(12,284,250)	(8,352,410)	(7,716,682)
Amortization of prior service cost	(416,566)	(416,566)	(2,781,539)	(2,781,539)
Recognized actuarial loss (gain)	212,740	707,787	(4,163,385)	(2,049,032)
Settlement	4,463,353	2,998,906	-	-
Total benefit cost	$ 6,421,008	$ 5,674,552	$(7,007,513)	$(3,946,514)
Pension and other postretirement benefits expense recognized in the consolidating statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 7,200,000	$ 5,200,000	$ -	$ -

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The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2023 and 2022:

	Fair Value Measurements at Reporting Date Using			
2023	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Common stock	$ 5,954,635	$ -	$ -	$ 5,954,635
Equity mutual funds	26,342,073	-	-	26,342,073
Index futures	-	81	-	81
Fixed-income securities	-	95,118,441	-	95,118,441
Commodities	-	-	-	-
Cash equivalents	5,655,816	-	-	5,655,816
Subtotal benefit plan assets	$ 37,952,524	$ 95,118,522	$ -	133,071,046
Investments measured at net asset value (NAV)				7,857,710
Total benefit plan assets				$ 140,928,756
2022	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 6,936,875	$ -	$ -	$ 6,936,875
Equity mutual funds	32,726,402	-	-	32,726,402
Index futures	-	3,000	-	3,000
Fixed-income securities	-	109,969,774	-	109,969,774
Commodities	-	43	-	43
Cash equivalents	6,585,046	-	-	6,585,046
Subtotal benefit plan assets	$ 46,248,323	$ 109,972,817	$ -	156,221,140
Investments measured at net asset value (NAV)				10,083,881
Total benefit plan assets				$ 166,305,021

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The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2023 and 2022:

	Fair Value Measurements at Reporting Date Using			
2023	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Equity mutual funds	$ 43,188,454	$ -	$ -	$ 43,188,454
Equity exchange traded funds	9,405,798	-	-	9,405,798
Fixed-income mutual funds	77,221,888	-	-	77,221,888
Fixed-income securities	-	16,963,326	-	16,963,326
Cash equivalents	505,281	-	-	505,281
Benefit plan assets	$130,321,421	$16,963,326	$ -	147,284,747
Uncleared cash disbursements from benefits paid				(1,638,519)
Investments measured at net asset value (NAV)				7,976,447
Total benefit plan assets				$153,622,675
2022	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Equity mutual funds	$ 40,339,233	$ -	$ -	$ 40,339,233
Equity exchange traded funds	9,611,932	-	-	9,611,932
Fixed-income mutual funds	72,425,790	-	-	72,425,790
Fixed-income securities	-	18,143,354	-	18,143,354
Cash equivalents	598,622	-	-	598,622
Benefit plan assets	$122,975,577	$18,143,354	$ -	141,118,931
Uncleared cash disbursements from benefits paid				(5,253,755)
Investments measured at net asset value (NAV)				7,930,628
Total benefit plan assets				$143,795,804

Investments that were measured at net asset value per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder upon no more than 30 days' notice. The values reported above are based on information provided by the fund manager.

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Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2023 and 2022, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2023	2022	2023		2022	
			Medical	Life	Medical	Life
Discount rate	5.35 %	5.61 %	5.35 %	5.35 %	5.57 %	5.57 %
Rate of compensation increase for next year	4.00	4.50	N/A	4.00	N/A	4.50
Rate to which compensation is assumed to decline (ultimate trend rate)	3.00	3.00	N/A	3.00	N/A	3.00
Year that rate reaches the ultimate trend	2026	2026	N/A	2026	N/A	2026

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2023 and 2022, were as follows:

	Pension Plan			
	For the Period July 1 through December 31, 2023	For the Period January 1 through June 30, 2023	For the Period October 1 through December 31, 2022	For the Period January 1 through September 30, 2022
Discount rate	5.44 %	5.61 %	5.65 %	3.08 %
Expected long-term return on plan assets	7.00	7.00	7.00	5.25

	2023	2022
Rate of compensation increase	4.50 %	4.50 %
Rate to which compensation is assumed to decline (ultimate trend rate)	3.00	3.00
Year that rate reaches the ultimate trend	2026	2026

	Other Postretirement Obligations			
	2023		2022	
	Medical	Life	Medical	Life
Discount rate	5.57 %	5.57 %	3.06 %	3.06 %
Expected long-term return on plan assets	5.83	6.50	4.47	5.00
Rate of compensation increase	N/A	4.50	N/A	3.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

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Assumed health care cost trend rates at December 31, 2023 and 2022, were as follows:

	2023	2022
Health care trend rate assumed for next year—participants under 65	6.75 %	7.00 %
Health care trend rate assumed for next year—participants over 65	6.75	7.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2029	2029

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2023 and 2022, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2023	2022	2023	2022
Asset category:				
Equity securities	29 %	30 %	39 %	39 %
Debt securities	71	70	61	61

Pension Plan and Other Postretirement Benefit Contributions— The Companies expect to contribute $5,300,000 to their Pension Plan and $24,500 to their Other Postretirement Benefits plan in 2024.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2024	$ 6,816,902	$ 6,738,069
2025	7,115,604	7,130,024
2026	7,513,364	7,469,791
2027	7,879,844	7,800,030
2028	8,193,339	8,085,042
Five years thereafter	48,196,446	44,675,809

Postemployment Benefits—The Companies follow the accounting guidance in ASC Topic 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial

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statements. The allocated amounts represent approximately a 34% and 66% split between OVEC and IKEC, respectively, as of December 31, 2023, and approximately a 31% and 69% split between OVEC and IKEC, respectively, as of December 31, 2022. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $8,808,588 and $10,567,071 at December 31, 2023 and 2022, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' pay contributed. In addition, the Companies provide contributions to eligible employees hired on or after January 1, 2015, of 3% to 5% of pay based on age and service. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2023 and 2022 were $2,001,057 and $1,948,147, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations

On March 10, 2005, the United States Environmental Protection Agency ("USEPA") issued the Clean Air Interstate Rule ("CAIR") that required significant reductions of SO_2 and NO_x emissions from coal-burning power plants. On March 15, 2005, the USEPA also issued the Clean Air Mercury Rule ("CAMR") that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NO_x, 2010 and 2015 for SO_2, and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization ("FGD") systems at both plants to comply with these rules. Following completion of the necessary engineering and permitting, construction was started on the FGD systems. The two Kyger Creek FGD systems were placed into service in 2011 and 2012, while the two Clifty Creek FGD systems were placed into service in 2013.

After the promulgation of CAIR and CAMR, a series of legal challenges to those rules resulted in their replacement with additional rules. CAMR was replaced with a rule referred to as the Mercury and Air Toxics Standards ("MATS") rule. The rule became final on April 16, 2012, and the Companies had to demonstrate compliance with MATS emission limits on April 16, 2015. The USEPA has recently proposed revising and updating the MATS rule, with an expected ruling in 2024. At this time, the Companies expect the previously installed controls will be proven to be adequate to meet the stringent emissions requirements outlined in the proposed new MATS rule.

Following the promulgation of CAIR, legal challenges resulted in the rule being remanded back to the USEPA. The USEPA subsequently promulgated a replacement rule to CAIR called the Cross-State Air Pollution Rule ("CSAPR"). The CASPR was also litigated and replaced with the CASPR Update, effective beginning the May 1, 2017, ozone season. The CSAPR Update did not replace

CSAPR; however, it required additional reductions in NO_x emissions from utilities in 22 states, including Ohio and Indiana, during the ozone season, which ranges from May through September. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update requirements in the 2017 ozone season. That strategy was standardized to meet future ozone season compliance obligations, and its execution provided for successful ozone season compliance through 2023. The CSAPR Update has also been subject to extensive litigation, and the D.C. Circuit Court of Appeals issued a decision on September 13, 2019, which remanded portions of this rule back to the USEPA to address. On October 15, 2020, the USEPA issued a proposed revision to the CSAPR Update in response to the court remand, and on March 15, 2021, the USEPA Administrator Regan signed a final rule revising the CSAPR Update to ensure states fully comply with their "good neighbor" obligations to comply with the 2008 Ozone National Ambient Air Quality Standards ("NAAQS"). This revised rule went into effect on June 29, 2021, and created a new Group 3 NO_x allowance trading program that applies to 12 states, including Indiana and Ohio. The rule changes did not impact the Companies' near-term compliance strategy and management does not expect for future operations to be materially impacted.

On February 28, 2022, the USEPA proposed the federal implementation rule known as the proposed Good Neighbor Transport Rule. This proposed rule was intended to fully resolve states' obligations under the "good neighbor" provisions of the Clean Air Act for the 2015 Ozone NAAQS. The USEPA signed the final rule in March 2023, effective during the 2023 ozone season, May 1, 2023, through September 30, 2023. The final rule is subject to extensive litigation, including an emergency stay request that is pending before the United States Supreme Court. The terms of the new rule are being evaluated for longer term impacts; however, the rule is not expected to materially impact the Companies near term compliance strategy for the ten units with selective catalytic reduction controls for NO_x emissions.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO_2 allowances available every year without having to rely on market purchases to comply with the CSAPR rules in their current form. Given the success of the Companies' NO_x ozone season compliance strategy, the purchase of additional NO_x allowances has not been needed for the past several years; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons. The more stringent NO_x regulations implemented by the USEPA in 2023 will result in additional restrictions on Unit 6 during the ozone season.

CCR Rule

The USEPA's CCR Rule became effective in October 2015 to regulate CCR as a nonhazardous solid waste. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule is self-implementing and currently does not require state action for the states of Indiana or Ohio. As a result of this self-implementing feature, the rule contains extensive recordkeeping and notice requirements, including requirements for disclosing CCR compliance information on the Companies' publicly available website.

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The Companies have been systematically implementing the applicable provisions of the CCR Rule and all revisions thereof. The Companies have completed all compliance obligations to date associated with the rule and are continuing to evaluate what, if any, impacts the South Fly Ash Pond and landfill at Kyger Creek and the West Boiler Slag Pond, Landfill, and Landfill Runoff Collection Pond at Clifty Creek will have on local groundwater quality. To date, these five CCR facilities continue to meet the groundwater monitoring standards of the CCR Rule. The Companies have been evaluating potential impacts to groundwater quality near the Boiler Slag Pond at Kyger Creek and the Landfill Runoff Collection Pond at Clifty Creek as required by the CCR Rule. The Companies have determined that statistically significant increases ("SSIs") in certain groundwater parameters are present at the two identified locations, and additional steps as defined by the CCR Rule are being taken. The evaluation of whether an SSI exists is a required component of the groundwater monitoring conditions of the CCR Rule. A determination that an SSI appears to be present requires additional evaluation to be undertaken by the Companies to determine if there are alternative sources that are influencing groundwater quality and, if necessary, to evaluate the extent of the groundwater quality impact. Concurrently, the Companies must continue to evaluate groundwater quality at each facility as required by the CCR Rule and determine what potential corrective actions are feasible to address the SSIs. The Companies conducted Alternative Source Demonstrations ("ASD") to determine if groundwater was being influenced by sources other than the CCR units. The ASDs were unable to definitively prove that alternative sources were directly influencing groundwater quality. As a result, the Companies worked with their qualified professional engineer to determine what corrective actions were feasible for each CCR unit. Following this a public meeting to discuss these options with the public was held prior to selecting a remedy. The Companies continue to work through the compliance requirements of the CCR Rule and remain in compliance.

Since the initial publication of the CCR rules in 2015, several legal, legislative, and regulatory events impacting the scope, applicability, and future CCR compliance obligations and timelines have also taken place. Final actions include: 1.) federal legislation (i.e., the Water Infrastructure Improvements for the Nation Act("WIIN")) that provides a pathway for states to seek approval for administering and enforcing the federal CCR program; 2.) The USEPA's issuance of a Phase I, Part I revision to the CCR rules on March 1, 2018; 3.) the D.C. Circuit Court's August 21, 2018, ruling, vacating and remanding portions of the CCR rule, and 4.) The USEPA's issuance of a final CCR Rule, Part A, which was published in the *Federal Register* on August 28, 2020. This final rule introduced a significant revision to the 2015 CCR rule requiring all impoundments that do not meet the liner requirements outlined in the rule to cease receiving CCR material and initiate closure by April 11, 2021, regardless of their overall compliance status. If that date is not technically feasible, an alternate date to cease receiving CCR material and initiate closure can be secured from the USEPA through a proposed extension request process, which was required by the USEPA no later than November 30, 2020. The surface impoundments at Kyger Creek and Clifty Creek were not constructed in a manner that meets the definition of a liner under the 2015 CCR rule. As a result, the Companies completed an engineering evaluation to develop preliminary closure designs for the impoundments, to determine a technically feasible timeline for discontinuing placement of CCR and non-CCR waste streams in these impoundments, and to initiate closure of the CCR impoundments consistent with the requirements of the rule. The Companies submitted technical justification documents to the USEPA in compliance with the November 30, 2020, deadline that demonstrated why additional time is needed to cease placement of CCR and non-CCR waste streams in the surface impoundments and initiate closure.

Separately, the proposed Part B revisions to the 2015 CCR rule outline the development of a federal permitting program to regulate and enforce the CCR rule at all applicable facilities consistent with the Congressional mandate outlined in the WIIN Act. This federal permit program would replace the current enforcement mechanism of a self-implementing rule enforced through citizen suits and place it back with the USEPA or any state regulator that receives primacy to implement the CCR permitting within their respective state. The Companies are actively monitoring these developments and adapting their CCR compliance program to ensure compliance obligations and timelines are adjusted accordingly.

The Companies secured various environmental permits in support of the CCR compliance strategy developed to comply with the CCR Rule, Part A and initiated work in 2021. On January 11, 2022, the IKEC Clifty Creek Station received a preliminary determination from USEPA proposing to deny the alternative closure deadlines IKEC requested for its two surface impoundments in the demonstration application filed by IKEC on November 30, 2020. However, the USEPA took no final action on the proposed denial of the Clifty Creek Station's application. The Kyger Creek Station filed a similar demonstration application in November of 2020. As of December 31, 2023, the Companies have not received final determinations from the USEPA for either the Clifty Creek or Kyger Creek Stations. The Companies executed their compliance strategy and maintained compliance with the CCR Rule by completing the work and ceasing receipt of CCR and non-CCR waste streams prior to October 15, 2023.

Changes in regulations or in the Companies' strategies for mitigating the impact of coal combustion residuals could potentially result in material increases to the asset retirement obligations. The Companies will revisit the demolition and decommissioning studies as appropriate throughout the process of executing closure of the CCR surface impoundments to maintain an appropriate estimated cost of ultimate facility closure and decommissioning.

NAAQS Compliance for SO_2

On June 22, 2010, the USEPA revised the Clean Air Act by developing and publishing a new one-hour SO_2 NAAQS of 75 parts per billion, which became effective on August 23, 2010. States with areas failing to meet the standard were required to develop state implemented plans to expeditiously attain and maintain the standard.

On August 15, 2013, the USEPA published its initial non-attainment area designations for the new one-hour SO_2, which did not include the areas around Kyger Creek or Clifty Creek. However, the amended rule does establish that at a minimum, sources that emit 2,000 tons of SO_2 or more per year be characterized by their respective states using either modeling of actual source emissions or through appropriately sited ambient air quality monitors.

In addition, the USEPA entered into a settlement agreement with Sierra Club/Natural Resources Defense Council in the U.S. District Court for the Northern District of California requiring the USEPA to take certain actions, including completing area designation by July 2, 2016, for areas with either monitored violations based on 2013-15 air quality monitoring or sources not announced for retirement that emitted more than 16,000 tons SO_2 or more than 2,600 tons with a 0.45 SO_2/mmBtu emission rate in 2012.

Both Kyger Creek and Clifty Creek directly or indirectly triggered one of the criteria and have been evaluated by the respective state regulatory agencies through modeling. The modeling results showed Clifty Creek could meet the new one-hour SO_2 limit using their current scrubber systems without any additional investment or modifications. Kyger Creek's modeling data was rejected by USEPA as inconclusive in 2016. As a result, the USEPA required Kyger Creek to install an SO_2 monitoring network around the plant and monitor ambient air quality beginning on January 1, 2017. Based on the first three years of data from that network, the Ohio Environmental Protection Agency prepared an updated petition to the USEPA in early 2020 requesting that the area in the county surrounding the plant be re-designated to attainment/unclassifiable with the one-hour SO_2 standard. The USEPA subsequently acted on this request and published a notice in the *Federal Register* proposing to make this re-designation. A final rulemaking approving the re-designation was expected in 2021; however, the USEPA failed to act on the re-designation. While a final decision has not been rendered as of December 31, 2023, the Company remains optimistic that the USEPA will render a decision as there is now six years of data supporting a re-designation determination. On February 26, 2019, the USEPA issued a final decision that it is retaining the existing primary SO_2 NAAQS at 75 parts per billion for the next five-year NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid more restrictive permit limits relative to its SO_2 emissions or the need for additional capital investment in major scrubber upgrades or modifications.

NAAQS compliance for Particulate Matter ("PM")

In 2021, the current administration signaled via executive order that it intends to revisit the 2020 PM NAAQS standard and lower it. On January 6, 2023, USEPA announced its proposed decision to revise the primary health-based annual $PM_{2.5}$ standard from its current level of 12.0 µg/m^3 to within the range of 9.0 to 10.0 µg/m^3. On March 6, 2024, the USEPA published a final rule revising and lowering the prior PM NAAQS to 9.0 µg/m^3. The new rule becomes effective on May 6, 2024, after which states will begin a multi-year process to determine if there are areas not meeting the new standard and, if so, the states will need to develop State Implementation Plans to address any non-attainment areas. Those plans will also need to be submitted to the USEPA for review and approval and could result in additional SO_2 and/or NO_x emissions reductions from the utility sector. The Companies will continue to monitor the activities that states undertake to comply with the new PM NAAQS to determine what impact a revision to this NAAQS standard could have on unit operations.

Steam Electric Effluent Limitations Guidelines

On September 30, 2015, the USEPA signed a new final rule governing Effluent Limitations Guidelines ("ELGs") for the wastewater discharges from steam electric power generating plants. The rule, which was formally published in the *Federal Register* on November 3, 2015, impacted future wastewater discharges from both the Kyger Creek and Clifty Creek stations.

The rule was intended to require power plants to modify the way they handle a number of wastewater processes. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the USEPA issued an administrative stay on the ELG rule. In June 2017, the USEPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The USEPA revised the rule redefining what constitutes "best

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available technology" for these two wastewater discharges and issued an updated final rule in the *Federal Register* on October 13, 2020. Based on the original rule and revisions captured in the 2020 update, the following impacts to each wastewater discharge are expected:

1. Kyger Creek was required to convert to dry fly ash handling by no later than December 31, 2023. Construction activities associated with dry fly ash conversion at Kyger Creek were completed in late 2022. The Clifty Creek Station was not impacted since the conversion to dry fly ash was completed prior to the implementation of this rule.

2. The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. As a result, Clifty Creek and Kyger Creek were converted to a closed-loop bottom ash management system for boiler slag, with up to a 10% purge based on each facility's total wetted volume. Each system was placed into service in advance of October 15, 2023.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges for arsenic, mercury, selenium, and nitrate/nitrite nitrogen. After reviewing the requirements of the 2015 edition of the rule, the Companies expected both Clifty Creek and Kyger Creek Stations to be able to meet the mercury and arsenic limitations with the current wastewater treatment technology; however, the Companies anticipated the potential need to add some form of biological, or equivalent nonbiological, treatment system downstream of each station's existing FGD wastewater treatment plant to meet the new nitrate/nitrite nitrogen and selenium limitations. Installation of new controls to meet the final effluent limitations contained in the revised rule was placed on hold while the USEPA reconsidered the 2015 ELG rule to ensure that the compliance strategy ultimately selected would be able to meet any revised requirements in the updated ELG rule. With the finalization of the October 13, 2020 ELG Revision, the Companies resumed evaluation of the appropriate technology, design, and schedule to achieve compliance with the new requirements, which included a change in the final effluent limitations for arsenic, nitrate/nitrite, mercury and selenium. The Companies worked with outside engineering resources, developed preliminary design reports, and conducted a pilot test at the Kyger Creek station in 2021. Further, the Companies worked with state agencies to request the revised ELG applicability date for FGD wastewater of no later than December 31, 2025. This compliance date is now incorporated into both plant's National Pollutant Discharge Elimination System ("NPDES") permits. Construction activities associated with the installation of bioreactors at both plants will commence late in the second quarter of 2024.

In March 2023, the USEPA issued a new draft ELG rule that proposes additional constraints on wastewater discharges at power plants. The draft rule has undergone public notices and comments, and the USEPA is expected to issue an updated ELG rule prior to June 2024. The Companies will continue to monitor USEPA regulatory actions on this pending final rule and will respond as necessary.

316(b) Compliance

The 316(b) rule was published as a final rule in the *Federal Register* on August 15, 2014, and impacts facilities that use cooling water intake structures designed to withdraw at least 2 million gallons per day from waters of the U.S., and those facilities who also have an NPDES permit. The rule requires such facilities to choose one of seven options specified by the rule to reduce impingement to fish and other aquatic organisms. Additionally, facilities that withdraw 125 million gallons or more per day must conduct entrainment studies to assist state permitting authorities in determining what site-specific controls are required to reduce the number of aquatic organisms entrained by each respective cooling water system.

The Companies have completed the required two-year fish entrainment studies and filed the reports with the respective state regulatory agencies consistent with regulatory requirements under 40 CFR Section 122.21(r).

The timeline for retrofits to the Kyger Creek Station's cooling water intake structure has been incorporated into its NPDES permit, with installation of the first sets of modified traveling water screens scheduled to be installed during the second quarter of 2024. Negotiation associated with the retrofits for the Clifty Creek Station are still underway with the Indiana Department of Environmental Management and will be incorporated into the facility's NPDES permit upon settlement.

Utility Greenhouse Gas Regulations

The USEPA has proposed regulations under Section 111(b) and (d) of the Clean Air Act to establish requirements for existing coal-fired and new natural gas fired steam electric generators. The proposed rules applicable to existing coal-fired steam electric generators larger than 100 MW in size may require those units to ultimately retire, co-fire with natural gas, and/or install carbon capture and sequestration technology to maintain long-term operations. This proposed regulation is anticipated to be finalized in mid-2024 and will be open to litigation once finalized, similar to USEPA regulatory attempts to establish carbon emission reductions for the utility sector have undergone. The Companies will continue to monitor USEPA regulatory actions on this pending final rule and will respond as necessary. Environmental rules and regulations discussed throughout the Environmental Matters footnote could require material additional capital expenditures or maintenance expenses in future periods.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for financial instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed-income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings as they are actively traded at quoted market prices. Certain fixed-income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed-income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed-income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

As of December 31, 2023 and 2022, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments, including money market mutual funds, equity mutual funds, and fixed-income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short-term in nature, their carrying amounts approximate fair value.

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Long-Term Investments— Assets measured at fair value on a recurring basis at December 31, 2023 and 2022, were as follows:

	Fair Value Measurements at Reporting Date Using		
2023	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Equity mutual funds	$ -	$ -	$ -
Equity exchange traded funds	-	-	-
Fixed-income securities	-	118,360,679	-
Cash equivalents	27,877,237	-	-
Total fair value	$ 27,877,237	$ 118,360,679	$ -
Assets not subject to fair value levels:			
Money Market Demand Deposit Account			45,135,443
Total long-term investments			$ 191,373,359
2022	**(Level 1)**	**(Level 2)**	**(Level 3)**
Equity mutual funds	$ 18,669,435	$ -	$ -
Equity exchange traded funds	40,207,434	-	-
Fixed-income securities	-	209,345,661	-
Cash equivalents	8,858,188	-	-
Total fair value	$ 67,735,057	$ 209,345,661	$ -
Assets not subject to fair value levels			-
Total long-term investments			$ 277,080,718

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values

OHIO VALLEY ELECTRIC CORPORATION
AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2023 and 2022, are as follows:

	2023		2022	
	Fair Value	Recorded Value	Fair Value	Recorded Value
Total	$ 929,279,387	$ 920,452,554	$ 953,838,516	$ 989,976,349

11. LEASES

OVEC has various operating leases for the use of other property and equipment.

On January 1, 2019, the Companies adopted ASC 842, *Leases* which, among other changes, requires the Companies to record liabilities classified as operating leases on the balance sheet along with a corresponding right-of-use asset. The Companies elected the package of practical expedients available for expired or existing contracts, which allowed them to carryforward their historical assessments of whether contracts are or contain leases, lease classification tests and treatment of initial direct costs. Further, the Companies elected to not separate lease components from non-lease components for all fixed payments and excluded variable lease payments in the measurement of right-of-use assets and lease obligations.

The Companies determine whether an arrangement is, or includes, a lease at contract inception. Leases with an initial term of 12 months or less are not recognized on the balance sheet. The Companies recognize lease expense for these leases on a straight-line basis over the lease term.

Operating lease right-of-use assets and liabilities are recognized at commencement date and initially measured based on the present value of lease payments over the defined lease term. Operating leases are immaterial as of December 31, 2023.

Contracts determined to be leases typically do not provide an implicit rate; therefore, the Companies use the estimated incremental borrowing rate at the time of lease commencement to discount the present value of lease payments. In order to apply the incremental borrowing rate, a portfolio approach with a collateralized rate is utilized. Assets were grouped based on similar lease terms and economic environments in a manner whereby the Companies reasonably expect that the application is not expected to differ materially from a lease-by-lease approach.

The Companies have finance leases for the use of vehicles, property, and equipment. The leases have remaining terms of 0 to 4 years. The components of lease expense are as follows:

	December 31, 2023
Finance lease cost:	
Amortization of leased assets	$ 899,456
Interest on lease liabilities	122,458
Total finance lease cost	$ 1,021,914

Supplemental cash flow information related to leases was as follows:

Financing cash flows from finance leases	$1,021,914
Weighted average remaining lease term:	
Finance leases	3
Weighted average discount rate:	
Finance leases	5.02 %

The amount in property under finance leases is $5,217,996 and $4,395,554 with accumulated depreciation of $2,674,161 and $1,796,855 as of December 31, 2023 and 2022, respectively.

Future maturities of finance lease liabilities are as follows:

Years Ending December 31	**Finance**
2024	$ 1,056,094
2025	933,731
2026	290,086
2027	199,514
Thereafter	76,636
Total future minimum lease payments	2,556,061
Less estimated interest element	212,980
Estimated present value of future minimum lease payments	$ 2,343,081

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by litigation, claims and uncertainties that arise in the ordinary course of business. The Companies regularly analyze current information and, as necessary provide accruals for probable and reasonably estimable liabilities on the eventual disposition of these matters. Management believes that the ultimate outcome of these matters will not have a significant, adverse effect on either the Companies' future results of operation or financial position.

* * * * * *

Deloitte.

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of Ohio Valley Electric Corporation:

Opinion

We have audited the consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, and the related consolidated statements of income and retained earnings and cash flows for the years then ended, and the related notes to the consolidated financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Companies as of December 31, 2023 and 2022, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Companies and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Companies' ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Companies' ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

/s/ DELOITTE & TOUCHE LLP

April 19, 2024

OVEC PERFORMANCE—A 5-YEAR COMPARISON

	2023	2022	2021	2020	2019
Net Generation (MWh)	**9,576,348**	11,014,053	10,071,966	9,025,018	11,238,298
Energy Delivered (MWh) to Sponsors	**9,581,490**	11,047,708	10,063,687	9,033,056	11,234,353
Maximum Scheduled (MW) by Sponsors	**2,057**	2,161	2,227	2,215	2,209
Power Costs to Sponsors	**$744,247,000**	$764,592,000	$662,365,000	$605,270,000	$640,801,000
Average Price (MWh) Sponsors	**$80.807**	$69.208	$65.819	$67.006	$57.040
Operating Revenues	**$855,002,000**	$761,499,000	$623,425,000	$551,718,000	$614,667,000
Operating Expenses	**$800,164,000**	$703,020,000	$559,559,000	$480,383,000	$554,642,000
Cost of Fuel Consumed	**$344,622,000**	$354,336,000	$260,174,000	$231,316,000	$274,843,000
Taxes (federal, state, and local)	**$15,418,000**	$12,078,000	$12,293,000	$12,203,000	$8,418,000
Payroll	**$53,924,000**	$53,135,000	$53,052,000	$53,461,000	$55,491,000
Fuel Burned (tons)	**4,500,247**	5,004,318	4,527,068	4,148,459	5,111,144
Heat Rate (Btu per kWh, net generation)	**10,845**	10,626	10,733	11,036	10,714
Unit Cost of Fuel Burned (per mmBtu)	**$2.88**	$3.05	$2.41	$2.04	$2.28
Equivalent Availability (percent)	**75.16**	66.30	70.8	78.9	78.2
Power Use Factor (percent)	**69.10**	90.51	76.56	60.80	76.23
Employees (year-end)	**525**	507	548	563	591

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

DIRECTORS

Ohio Valley Electric Corporation

[1] **THOMAS ALBAN**, Columbus, Ohio
Vice President, Power Generation
Buckeye Power, Inc.

ERIC D. BAKER, Cadillac, Michigan
President and Chief Executive Officer
Wolverine Power Supply Cooperative, Inc.

[1,2] **LONNIE E. BELLAR,** Louisville, Kentucky
Chief Operating Officer
LG&E and KU Energy LLC

STEVEN K. NELSON, Coshocton, Ohio
Chairman, Buckeye Power Board of Trustees
The Frontier Power Company

[2] **PATRICK W. O'LOUGHLIN**, Columbus, Ohio
President and Chief Executive Officer
Buckeye Power, Inc.

OLENGER L. PANNELL, Akron, Ohio
Vice President, Compliance & Regulatory Services,
Chief FERC Compliance Officer
FirstEnergy Corp.

THOMAS A. RAGA, Dayton, Ohio
Vice President, AES US Utilities
AES Corporation

[2] **MARC REITTER**, Gahanna, Ohio
President and Chief Operating Officer, AEP Ohio
American Electric Power Company, Inc.

[2] **BRIAN D. SHERRICK**, Columbus, Ohio
Vice President, Generation Shared Services
American Electric Power Service Corporation.

[1] **PHILLIP R. ULRICH**, Columbus, Ohio
Executive Vice President, Chief Human Resources Officer
American Electric Power Company, Inc.

[2] **JOHN A. VERDERAME**, Charlotte, North Carolina
Vice President, Fuels & Systems Optimization
Duke Energy Corporation

[1] **AARON D. WALKER**, Charleston, West Virginia
President and Chief Operating Officer
Appalachian Power

HEATHER WATTS, Evansville, Indiana
Vice President, Associate General Counsel Regulatory Legal
CenterPoint Energy

Indiana-Kentucky Electric Corporation

STEVEN F. BAKER, Fort Wayne, Indiana
President and Chief Operating Officer
Indiana Michigan Power

KATHERINE K. DAVIS, Fort Wayne, Indiana
Vice President, External Affairs
Indiana Michigan Power

DAVID S. ISAACSON, Fort Wayne, Indiana
Vice President –Distribution Region Ops
Indiana Michigan Power

[2] **PATRICK W. O'LOUGHLIN**, Columbus, Ohio
President and Chief Executive Officer
Buckeye Power, Inc.

[2] **BRIAN D. SHERRICK**, Columbus, Ohio
Vice President, Generation Shared Services
American Electric Power Service Corporation.

Officers—OVEC AND IKEC

BRIAN D. SHERRICK
President

JUSTIN J. COOPER
Vice President,
Chief Operating Officer and
Chief Financial Officer

KASSANDRA K. MARTIN
Secretary and Treasurer

JULIE SHERWOOD
Assistant Secretary and
Assistant Treasurer

[1]Member of Human Resources Committee.
[2]Member of Executive Committee.

Execution Copy

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.

1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

ARTICLE 3

[RESERVED]

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.

4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article* 5.

5.02. *Energy Charge.* The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge.* During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of $2.089 multiplied by the total number of shares of capital stock of the par value of $100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); provided that, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge.* The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

5.05. *Minimum Loading Event Costs.* To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments.* The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

8.03. *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver.* Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation; the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10^{th}) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties*. Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in Schedule 10.01(c) hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default*. If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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Its ______________________

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By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active 12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its Vice President

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active 12026116.4

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By [signature]
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its VICE PRESIDENT

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By Anthony J. Ahern
Its President & CEO

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By Gary Stephenson
Its EXECUTIVE VICE PRESIDENT
Gary Stephenson

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By Gary R Leidich
Its President

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By [signature]
Its Sr Vice President

030860-0015-02023-Active 12026116.4

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its VP Trans. & Generation Services

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its General Manager, Electric Supply

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By Ronald E. Christian
Its President

3

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur
Its President

APPROVED AS TO FORM:

B. E. Valice

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

SCHEDULE 10.01(c)

Allegheny Energy Supply Company, L.L.C.

and

Monongahela Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Appalachian Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

SCHEDULE 10.01(c)

Buckeye Power Generating, LLC

None

SCHEDULE 10.01(c)

Columbus Southern Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

The Dayton Power and Light Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Duke Energy Ohio, Inc.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

FirstEnergy Generation Corp.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Indiana Michigan Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Filing with the Indiana Utility Regulatory Commission

SCHEDULE 10.01(c)

Kentucky Utilities Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Louisville Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Ohio Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Peninsula Generation Cooperative

None

SCHEDULE 10.01(c)

Southern Indiana Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL,
CITIZENS UTILITY BOARD, AND SIERRA CLUB
DATA REQUEST SET NO. AG-CUB-SC 1
CASE NO. U-21596

DATA REQUEST NO. AG-CUB-SC 1-13

Request

Produce any and all meeting minutes of the OVEC Operating Committee from January 1, 2022 to present.

Response

Please see AG DR 1-13 CONFIDENTIAL Attachment 1 for the requested documents.

Preparer:
Todd A. Johnston

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL,
CITIZENS UTILITY BOARD, AND SIERRA CLUB
DATA REQUEST SET NO. AG-CUB-SC 1
CASE NO. U-21596

DATA REQUEST NO. AG-CUB-SC 1-20

Request

Refer to Exhibit IM-9:

a.: Describe in detail the reasons for the projected higher level of OVEC purchases over the plan period compared to the projection in Exhibit IM-9 in U-21427.

b.: Describe in detail the reasons for the projected higher level of AEG purchases in each year of the 5-year forecast compared to the same projection in Exhibit IM-9 in U-21427.

Response

I&M objects to the Requests to the extent they seek an analysis, calculation, or compilation which has not already been performed, and which I&M objects to performing.

a. Subject to and without waiving that objection, I&M states that the OVEC purchase MWh was projected by the PLEXOS® simulation model based on its energy price versus the PJM market price. Therefore, the purchase level will vary based on price competitiveness.

b. Subject to and without waiving that objection, I&M states that the AEG purchase is based on the Fossil Generation MWh of Rockport Unit 1 generation dispatch which was projected by the PLEXOS® simulation model based on its energy price versus the PJM market price. Therefore, the generation level will vary based on price competitiveness.

Preparer:
Hazel A. Baker

As To Objection:
Counsel

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL,
CITIZENS UTILITY BOARD, AND SIERRA CLUB
DATA REQUEST SET NO. AG-CUB-SC 1
CASE NO. U-21596

DATA REQUEST NO. AG-CUB-SC 1-9

Request

Provide I&M's monthly projection for I&M's share of the OVEC units over the PSCR plan year and five-year forecast period 2025 – 2028 for each of the following. If I&M does not project any of the requested values, please indicate so in the response:

a.: Generation (MWh) on peak and off-peak by month.

b.: Percent of generation assumed to be dispatched on peak and off peak (%) (For purposes of your response, if the Company has a standard definition of on- and off-peak power used for its customary energy transactions, please provide this definition. Otherwise please define on- peak power as power used during weekday hours ending 8 a.m. to 11 p.m., and off-peak as all other hours. Please indicate whether these values are before or after deduction for transmission losses.)

c.: Demand charges ($)

d.: Energy Charges ($)

e.: Transmission Charge ($)

f.: PJM Expenses / Fees ($)

g.: ICAP (MW)

h.: Capacity value ($/MW-day)

i.: Energy market revenues ($)

j.: Ancillary services revenues ($)

k.: On and off-peak market prices used to project energy market revenues by month.

Response

a. c. d. I&M objects to the request to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving this objection, I&M will provide the requested information pursuant to the protective order issued in this case. In addition, I&M objects to the Request for on peak and off-peak generation by month to the extent it seeks an analysis, calculation, or compilation which has not already been performed, and which I&M objects to performing. Without waiving these objections, I&M states: Please see "AG 1-9 CONFIDENTIAL Attachment 1.xlsx" for the total monthly unit generation by month, the Demand Charges ($) and Energy Charges ($).

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL,
CITIZENS UTILITY BOARD, AND SIERRA CLUB
DATA REQUEST SET NO. AG-CUB-SC 1
CASE NO. U-21596

b. I&M objects to the Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed, and which I&M objects to performing.

e. The OVEC share of transmission charge for I&M is not available. This data is included in the Demand Charge, which is forecast and reported as an aggregated I&M Demand Charge and is provided in subpart c.

f. The OVEC share of PJM Expenses/Fees assigned to I&M is not available. The Company does not forecast this data.

g. Please see attachment "AG 1-9 Attachment 2.xlsx".

h. Please see attachment "AG 1-9 Attachment 3.xlsx".

i. The energy market revenue earned by I&M's share of the OVEC units is not available. This data is forecast and reported as an aggregated I&M total.

j. The Ancillary services revenue is not available. The Company does not forecast that data.

k. Please see attachment "AG 1-9 CONFIDENTIAL Attachment 4.xlsx".

<u>Preparer:</u>
Hazel A. Baker

<u>As To Objection:</u>
Counsel

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL,
CITIZENS UTILITY BOARD, AND SIERRA CLUB
DATA REQUEST SET NO. AG-CUB-SC 1
CASE NO. U-21596

DATA REQUEST NO. AG-CUB-SC 1-17

Request

Produce the most recent AEP Fundamentals Forecast.

Response

Please see attachment "AG 1-17 Attachment 1.xlsx".

Preparer:
Mark O'Brien

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1			**Power Prices ($/MWh) - Nominal**											
2			PJM_AEP		SPP_Central		SPP_KSMO		ERCOT_NORTH		ERCOT_South		ERCOT_West	
3	Year	Month	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
4	2025	Jan-25	27.77	25.96	22.26	21.31	21.34	19.88	0.00	0.00	0.00	0.00	0.00	0.00
5	2025	Feb-25	25.18	24.04	22.08	20.94	21.33	19.21	0.00	0.00	0.00	0.00	0.00	0.00
6	2025	Mar-25	24.58	23.96	19.49	18.90	18.28	17.51	0.00	0.00	0.00	0.00	0.00	0.00
7	2025	Apr-25	23.16	21.83	17.92	16.49	17.16	15.58	0.00	0.00	0.00	0.00	0.00	0.00
8	2025	May-25	25.19	22.98	21.13	19.44	19.60	17.62	0.00	0.00	0.00	0.00	0.00	0.00
9	2025	Jun-25	25.56	23.25	22.62	21.16	21.10	18.70	0.00	0.00	0.00	0.00	0.00	0.00
10	2025	Jul-25	29.18	25.04	27.76	23.71	26.69	21.62	0.00	0.00	0.00	0.00	0.00	0.00
11	2025	Aug-25	30.05	25.33	27.70	23.23	26.54	20.59	0.00	0.00	0.00	0.00	0.00	0.00
12	2025	Sep-25	30.47	25.43	25.05	21.74	23.91	19.65	0.00	0.00	0.00	0.00	0.00	0.00
13	2025	Oct-25	26.51	24.04	22.22	19.67	21.07	17.40	0.00	0.00	0.00	0.00	0.00	0.00
14	2025	Nov-25	23.39	22.44	19.23	18.20	17.83	16.61	0.00	0.00	0.00	0.00	0.00	0.00
15	2025	Dec-25	26.20	24.48	22.49	21.87	21.10	20.08	0.00	0.00	0.00	0.00	0.00	0.00
16	2026	Jan-26	31.74	28.70	27.23	25.49	25.86	23.42	0.00	0.00	0.00	0.00	0.00	0.00
17	2026	Feb-26	27.88	26.72	25.60	23.07	25.03	20.96	0.00	0.00	0.00	0.00	0.00	0.00
18	2026	Mar-26	26.03	24.98	20.63	19.90	19.42	18.08	0.00	0.00	0.00	0.00	0.00	0.00
19	2026	Apr-26	27.12	25.17	19.72	18.11	18.84	16.99	0.00	0.00	0.00	0.00	0.00	0.00
20	2026	May-26	26.54	24.14	22.92	20.87	21.37	18.64	0.00	0.00	0.00	0.00	0.00	0.00
21	2026	Jun-26	27.94	24.91	22.87	21.31	21.71	19.18	0.00	0.00	0.00	0.00	0.00	0.00
22	2026	Jul-26	34.93	28.27	29.31	24.74	28.56	22.87	0.00	0.00	0.00	0.00	0.00	0.00
23	2026	Aug-26	32.84	26.77	29.88	24.56	28.54	21.70	0.00	0.00	0.00	0.00	0.00	0.00
24	2026	Sep-26	29.68	24.99	25.94	22.27	24.96	20.23	0.00	0.00	0.00	0.00	0.00	0.00
25	2026	Oct-26	25.76	23.53	23.53	20.62	22.30	18.08	0.00	0.00	0.00	0.00	0.00	0.00
26	2026	Nov-26	24.86	23.78	20.96	19.53	19.30	17.53	0.00	0.00	0.00	0.00	0.00	0.00
27	2026	Dec-26	28.23	26.72	26.05	24.80	24.72	22.83	0.00	0.00	0.00	0.00	0.00	0.00
28	2027	Jan-27	36.70	32.81	31.24	29.06	29.88	26.90	0.00	0.00	0.00	0.00	0.00	0.00
29	2027	Feb-27	31.26	29.17	29.65	25.86	29.19	23.27	0.00	0.00	0.00	0.00	0.00	0.00
30	2027	Mar-27	29.33	27.81	22.54	20.95	21.02	18.79	0.00	0.00	0.00	0.00	0.00	0.00
31	2027	Apr-27	29.23	27.68	23.57	21.10	21.89	18.76	0.00	0.00	0.00	0.00	0.00	0.00
32	2027	May-27	32.14	28.87	27.60	23.82	25.98	21.12	0.00	0.00	0.00	0.00	0.00	0.00
33	2027	Jun-27	30.15	26.69	28.40	25.57	26.33	21.93	0.00	0.00	0.00	0.00	0.00	0.00
34	2027	Jul-27	37.00	29.36	35.72	28.98	35.19	26.92	0.00	0.00	0.00	0.00	0.00	0.00
35	2027	Aug-27	38.42	30.17	36.40	28.89	34.86	25.29	0.00	0.00	0.00	0.00	0.00	0.00
36	2027	Sep-27	36.94	29.84	33.29	27.14	32.04	23.88	0.00	0.00	0.00	0.00	0.00	0.00
37	2027	Oct-27	30.51	27.79	28.52	23.15	27.04	20.15	0.00	0.00	0.00	0.00	0.00	0.00
38	2027	Nov-27	26.57	25.32	23.66	21.56	21.42	18.73	0.00	0.00	0.00	0.00	0.00	0.00
39	2027	Dec-27	29.68	28.08	27.02	25.76	25.84	23.87	0.00	0.00	0.00	0.00	0.00	0.00
40	2028	Jan-28	38.72	33.27	30.92	28.83	29.71	26.77	0.00	0.00	0.00	0.00	0.00	0.00
41	2028	Feb-28	31.55	29.79	30.83	26.81	30.65	24.50	0.00	0.00	0.00	0.00	0.00	0.00
42	2028	Mar-28	30.52	28.60	22.84	21.35	21.40	19.19	0.00	0.00	0.00	0.00	0.00	0.00
43	2028	Apr-28	29.86	28.29	24.29	21.81	22.66	19.41	0.00	0.00	0.00	0.00	0.00	0.00
44	2028	May-28	34.00	29.61	29.42	24.63	28.00	22.26	0.00	0.00	0.00	0.00	0.00	0.00
45	2028	Jun-28	31.70	27.07	28.78	26.28	26.82	22.64	0.00	0.00	0.00	0.00	0.00	0.00
46	2028	Jul-28	39.50	30.55	37.75	30.10	37.67	28.42	0.00	0.00	0.00	0.00	0.00	0.00
47	2028	Aug-28	40.35	31.30	37.88	30.14	36.11	26.33	0.00	0.00	0.00	0.00	0.00	0.00
48	2028	Sep-28	37.59	30.14	34.00	27.63	32.88	24.38	0.00	0.00	0.00	0.00	0.00	0.00
49	2028	Oct-28	31.58	28.44	28.89	23.55	27.38	20.76	0.00	0.00	0.00	0.00	0.00	0.00
50	2028	Nov-28	27.73	26.08	25.11	22.46	23.11	19.66	0.00	0.00	0.00	0.00	0.00	0.00
51	2028	Dec-28	30.76	28.72	28.92	27.69	27.81	25.98	0.00	0.00	0.00	0.00	0.00	0.00
52	2029	Jan-29	39.42	34.21	33.55	30.60	32.16	28.01	0.00	0.00	0.00	0.00	0.00	0.00
53	2029	Feb-29	40.16	34.08	33.30	29.03	33.14	26.39	0.00	0.00	0.00	0.00	0.00	0.00
54	2029	Mar-29	32.75	30.48	24.03	22.23	22.37	19.83	0.00	0.00	0.00	0.00	0.00	0.00
55	2029	Apr-29	32.22	29.35	25.36	22.64	23.55	19.84	0.00	0.00	0.00	0.00	0.00	0.00
56	2029	May-29	38.40	31.75	31.12	25.71	29.61	23.09	0.00	0.00	0.00	0.00	0.00	0.00
57	2029	Jun-29	38.97	31.41	32.06	29.11	30.17	25.29	0.00	0.00	0.00	0.00	0.00	0.00
58	2029	Jul-29	43.95	33.58	40.85	32.14	40.96	30.28	0.00	0.00	0.00	0.00	0.00	0.00
59	2029	Aug-29	44.70	34.58	39.98	32.01	37.93	27.86	0.00	0.00	0.00	0.00	0.00	0.00
60	2029	Sep-29	41.52	32.96	36.85	29.12	35.57	25.52	0.00	0.00	0.00	0.00	0.00	0.00
61	2029	Oct-29	36.09	30.42	31.20	24.88	29.68	21.91	0.00	0.00	0.00	0.00	0.00	0.00
62	2029	Nov-29	30.90	28.67	27.33	24.05	25.27	21.02	0.00	0.00	0.00	0.00	0.00	0.00
63	2029	Dec-29	34.29	30.93	30.43	29.20	29.25	27.38	0.00	0.00	0.00	0.00	0.00	0.00

	AA	AB	AC	AD	AE	AF	AG
1	Natural Gas ($/mmbtu) - Nominal						
2							
3	Henry Hub	TCO Pool	ninion South Point F	TCO Deliv	HSC	PEPL TX-OK	wing Service Add
4	3.30	3.17	2.90	3.66	3.11	2.95	0.30
5	2.91	2.72	2.50	3.20	2.79	2.95	0.30
6	3.06	2.86	2.64	3.35	2.96	3.11	0.31
7	2.77	1.84	1.12	2.17	2.68	2.40	0.31
8	2.97	2.69	2.54	3.04	2.91	2.73	0.31
9	3.17	2.73	1.45	3.07	3.11	2.90	0.31
10	3.44	2.89	1.86	3.24	3.38	3.13	0.31
11	3.45	3.12	3.03	3.48	3.37	3.07	0.31
12	3.00	2.77	2.63	3.12	2.88	2.96	0.31
13	3.09	2.72	2.44	3.07	2.97	2.82	0.31
14	3.09	2.23	1.92	2.71	2.88	2.69	0.31
15	3.44	2.93	2.70	3.42	3.22	3.33	0.31
16	4.07	3.91	3.53	4.42	3.89	4.02	0.31
17	3.46	3.45	3.19	3.95	3.34	3.68	0.31
18	3.86	3.25	2.61	3.74	3.77	3.31	0.31
19	3.11	2.86	2.77	3.21	3.02	2.80	0.31
20	3.26	2.79	1.59	3.14	3.20	3.02	0.31
21	3.19	2.79	2.60	3.14	3.14	2.87	0.31
22	3.52	3.17	3.08	3.52	3.46	3.27	0.31
23	3.49	3.08	3.00	3.43	3.41	3.29	0.31
24	3.24	2.72	1.62	3.06	3.11	2.85	0.32
25	3.24	2.62	1.48	2.97	3.12	3.00	0.32
26	3.46	2.60	2.04	3.09	3.24	3.05	0.32
27	3.99	3.52	3.31	4.02	3.77	3.95	0.32
28	4.39	4.49	4.01	5.01	4.20	4.61	0.32
29	4.18	4.03	3.65	4.55	4.06	4.05	0.32
30	4.04	3.84	3.63	4.35	3.94	4.12	0.32
31	3.90	3.74	3.61	4.11	3.81	3.81	0.32
32	3.94	3.88	3.60	4.26	3.87	3.90	0.32
33	4.07	3.58	2.91	3.95	4.01	3.83	0.32
34	4.23	3.78	2.53	4.15	4.16	3.97	0.32
35	4.19	3.94	3.76	4.32	4.10	4.13	0.32
36	4.03	3.83	3.71	4.20	3.90	3.89	0.32
37	3.91	3.63	3.50	4.00	3.80	3.78	0.32
38	3.99	3.23	2.84	3.72	3.78	3.61	0.32
39	4.20	3.62	3.58	4.12	3.98	4.00	0.32
40	4.47	4.43	4.02	4.95	4.28	4.36	0.32
41	4.25	4.10	3.84	4.62	4.13	4.14	0.32
42	4.12	3.84	3.76	4.35	4.02	4.18	0.33
43	3.98	3.83	3.70	4.20	3.89	3.85	0.33
44	4.02	3.83	3.62	4.21	3.95	4.04	0.33
45	4.14	3.50	2.46	3.87	4.09	3.80	0.33
46	4.30	3.70	2.59	4.07	4.24	3.95	0.33
47	4.26	4.04	3.85	4.41	4.18	4.22	0.33
48	4.10	3.85	3.77	4.22	3.97	3.89	0.33
49	3.98	3.66	3.54	4.03	3.87	3.84	0.33
50	4.06	3.25	2.92	3.74	3.85	3.74	0.33
51	4.27	3.93	3.31	4.44	4.05	4.16	0.33
52	4.45	3.95	3.69	4.46	4.26	4.25	0.33
53	4.24	4.14	3.80	4.66	4.12	4.27	0.33
54	4.10	3.85	3.74	4.36	4.00	4.18	0.33
55	3.96	3.78	3.67	4.15	3.87	3.79	0.33
56	4.00	3.79	3.59	4.16	3.93	3.86	0.33
57	4.12	3.92	3.74	4.29	4.07	4.06	0.33
58	4.28	3.68	2.61	4.05	4.22	3.99	0.33
59	4.24	4.07	3.89	4.45	4.16	4.33	0.33
60	4.08	3.75	3.74	4.11	3.95	3.93	0.33
61	3.96	3.62	3.48	3.98	3.85	3.85	0.34
62	4.04	3.62	2.67	4.12	3.83	4.00	0.34
63	4.25	3.82	3.61	4.33	4.03	4.18	0.34

PJM CONE 2026/2027 Report

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APRIL 21, 2022

Executive Summary

PJM Interconnection, L.L.C (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff. This report presents our estimates of the Cost of New Entry (CONE) for the 2026/2027 commitment period, recommendations regarding the methodology for calculating the net energy and ancillary service revenue offset (E&AS Offset), and our recommendation for the selection of the reference resource. A separate, concurrently-released report presents our review of the VRR curve shape.

Background

The Variable Resource Requirement (VRR) curves set the price at the target reserve margin at approximately Net Cost of New Entry (Net CONE), such that the resource adequacy requirement will be achieved if suppliers enter the market when prices are at least Net CONE. In a downward-sloping curve, slightly lower reliability will be tolerated only when prices exceed Net CONE and some incremental capacity will be procured when the incremental cost is relatively low.

Net CONE is estimated by selecting an appropriate reference resource that economically enters the PJM market, determining its characteristics and its capital costs and ongoing operating and maintenance costs; then estimating a first-year capacity payment needed for entry, given likely trajectories of future total revenues and E&AS offsets.

A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support. Another common misconception is that the Net CONE parameter sets capacity prices. In fact, capacity prices are determined by the intersection of the VRR curves and the supply curves. Long-run market clearing prices depend on the actual prices at which new competitive supply is willing to enter rather than the administrative Net CONE estimates, while the VRR curve determines only the quantity of capacity procured (short-term price impacts of changes in administrative Net CONE may be larger, depending on the elasticity of supply).

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

CONE Area	Elevation	Max. Summer Temperature	Relative Humidity
	(ft)	*(°F)*	*(%RH)*
1 EMAAC	330	92.2	55.3
2 SWMAAC	150	96.2	44.2
3 Rest of RTO	990	89.9	49.7
4 WMAAC	1,200	91.4	48.9

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 1174 / 1144 / 1133*
Net Heat Rate (HHV in Btu/kWh)	
without Duct Firing	6365 / 6383 / 6359 / 6368*
with Duct Firing	6602 / 6619 / 6593 / 6601*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

2025/2026 Base Residual Auction Report

July 30, 2024

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Introduction

This document provides information for PJM stakeholders regarding the results of the 2025/2026 Reliability Pricing Model (RPM) Base Residual Auction (BRA).

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Across the RTO, seasonal sell offers must account for annual CP commitments by matching summer-period and winter-period sell offers.

The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

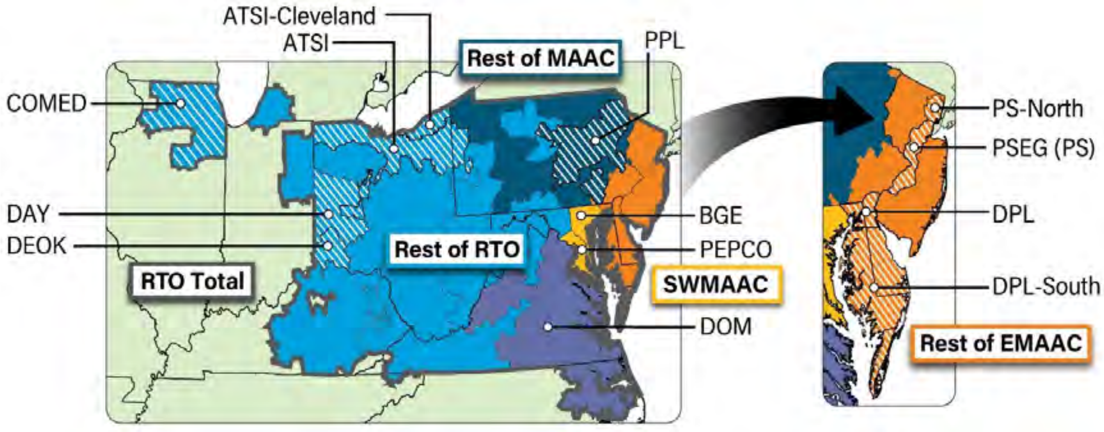
An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY, DOM and DEOK were modeled as LDAs in the 2025/2026 RPM Base Residual Auction. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA.

Locational Deliverability Area Definition

Locational Deliverability Areas (LDAs) defined as "(rest of)" do not include figures from modeled child LDAs contained within the parent LDA. For example, the PS (rest of) LDA does not include PS-NORTH within its totals.	• EMAAC total includes DPL-SOUTH, PS-NORTH, PS (rest of), EMAAC (rest of). • SWMAAC total includes PEPCO, BGE, SWMAAC (rest of). • MAAC total includes EMAAC total, SWMAAC total, PPL, MAAC (rest of).	RTO total includes MAAC total, ATSI (rest of), ATSI-Cleveland, COMED, DAY, DEOK, DOM, RTO (rest of). See Map 1.

Map 1. PJM LDAs



Executive Summary

The 2025/2026 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 135,684 MW of unforced capacity in the RTO from non-energy efficiency annual, summer-period, and winter-period resources representing a 18.6% reserve margin. Energy Efficiency (EE) resources are excluded from this calculation because their impact is reflected in a lower load forecast and therefore not used to meet the Reliability Requirement. The total cost to load for the 2025/2026 BRA was $14.7 billion, which includes the cost of EE. The reserve margin for the entire RTO, which includes Fixed Resource Requirement (FRR) is 18.5% or 0.7 percentage points higher than the target reserve margin of 17.8%. This is a significant reduction in the overall reserve margin, which includes FRR, from the 2024/2025 BRA. The 2024/2025 overall reserve margin for the entire RTO was 20.4%, or 5.7 percentage points higher than the target reserve margin of 14.7% The 2025/26 to 2024/25 Delivery Year supply and demand changes are not straightforward comparisons because of the implementation of marginal Effective Load Carrying Capability accreditation for all resources and the associated reduction of the reliability requirement through the Forecast Pool Requirement (FPR) as well as the transition of load from FRR into RPM. The Delivery Year over Delivery Year unforced capacity or reliability requirement comparisons in the report have not been adjusted for these changes.

Supply offered into the RPM capacity market, excluding EE resources, declined 13,252.1 MW from 148,945.7 MW in the 2024/2025 BRA to 135,692.3 MW in the 2025/2026 BRA. This is the fourth BRA in a row where the total capacity offered from non-EE resources has declined. The number of constrained LDAs dropped from five to two in the 2025/2026 BRA. The total amount of capacity, excluding EE Resources, in RPM that cleared decreased by 5,743.6 MW from 140,415.8 MW in the 2024/2025 BRA to 134,672.2 MW in the 2025/2026 BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all Existing Generation Capacity Resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

Table 1. Comparison of BRA Clearing Prices by Delivery Year by LDA

		BRA Resource Clearing Prices ($/MW-day)		
Capacity Type	BRA	Rest of RTO	BGE	DOM
Capacity Performance	2025/26	*$269.92*	*$466.35*	*$444.26*
	2024/25	*$28.92*	*$73.00*	-

Note: Clearing prices in bold indicate constrained LDA

The following is a list of new market rules or planning parameter changes that may have impacted the auction results:

- Planning Parameters (please see the Planning Parameters Report) changes which include:
  - 3,243 MW increase in forecasted load
  - IRM increase from 14.7% to 17.8%
- Significant decrease in overall supply from retirements (actual retirements plus must offer exceptions for future retirements), change in status from capacity resource to energy only and must offer exceptions for exports (see change of status and must offer exception report)

- Critical Issue Fast Path (CIFP) changes were approved by FERC (ER24-99-000). These changes included marginal resource accreditation (ELCC), Forecast Pool Requirement (FPR) and a binding notice of intent for planned resources among other changes.
- Dominion FRR has changed to RPM and therefore the entire Dominion zone is now in RPM.
- Net CONE values used to determine the VRR Curve changed significantly in some LDAs. In most cases, LDAs received lower Net CONE values, and the range was between +4.1% in the PE zone to -80.6% in the BGE zone.

Note: This BRA was conducted under a compressed auction schedule where the auction occurred ~10 months prior to the start of the delivery year. A typical BRA is held more than three years before the start of the delivery year. The prior BRA was conducted under the same compressed auction schedule.

Detailed Report

Table 2 contains a summary of the RTO clearing prices, cleared unforced capacity and implied cleared reserve margins for the 2015/2016 through 2025/2026 RPM BRAs. The Reserve Margin presented in Table 2 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the FRR alternative). The reserve margin for the entire RTO, which includes FRR and RPM load, is 18.5%, or 0.7 percentage points higher than the target reserve margin of 17.8%.

Table 2. RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results				
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin	Total Reserve Margin[1]	Total Cost to Load ($ billion)
2015/16[2]	$136.00	164,561.2	19.7%	19.3%	$9.7
2016/17[3]	$59.37	169,159.7	20.7%	20.3%	$5.5
2017/18	$120.00	167,003.7	20.1%	19.7%	$7.5
2018/19	$164.77	166,836.9	20.2%	19.8%	$10.9
2019/20	$100.00	167,305.9	22.9%	22.4%	$7.0
2020/21[4]	$76.53	165,109.2	23.9%	23.3%	$7.0
2021/22	$140.00	163,627.3	22.0%	21.5%	$9.3
2022/23	$50.00	144,477.3	21.1%	19.9%	$3.9
2023/24	$34.13	144,870.6	21.6%	20.3%	$2.2
2024/25	$28.92	147,478.9	21.7%	20.4%	$2.2
2025/26[5]	$269.92	135,684.0	18.6%	18.5%	$14.7

[1] Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1; [2] 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; [3] 2016/2017 BRA includes EKPC zone;
[4] Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers; [5] DOM zone included in RPM

Figure 1 represents the trend in BRA capacity price by delivery year for RTO, EMAAC, SWMAAC and MAAC. For 2025/2026, all four LDAs cleared at $269.97. This clearing price was an increase from $28.92 in RTO, $49.49 in MAAC and SWMAAC and $54.95 in EMAAC in the 2024/2025 BRA. The number of constrained LDAs decreased from five LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK) to two LDAs (BGE and DOM).

Figure 1. BRA Clearing Prices by Delivery Year for Major LDAs

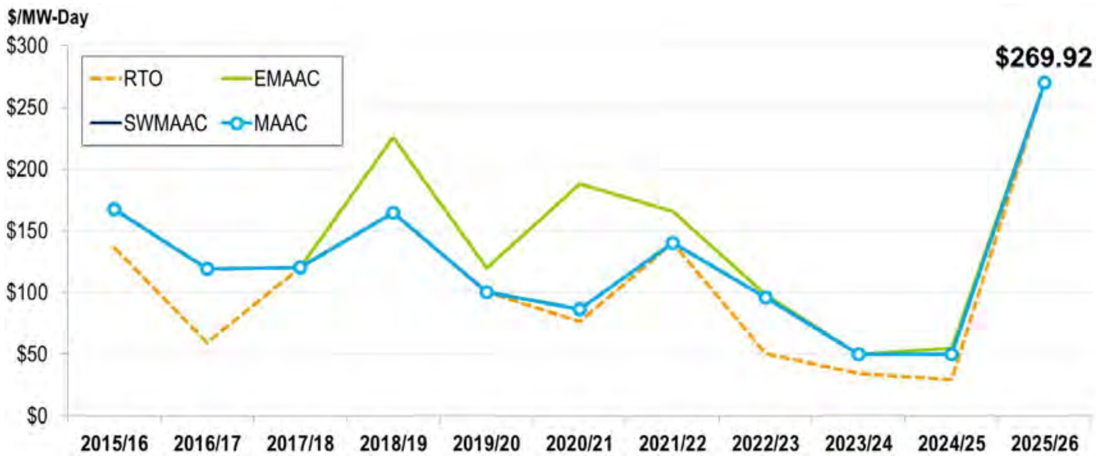


Table 3 provides the total offered and cleared MWs and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA. Since BGE and DOM were constrained LDAs, they cleared at a higher price than the rest of RTO or $466.35 and $444.26, respectively.

Since BGE and DOM were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDAs for the 2025/2026 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

For 2025/2026, only 20.7 MW UCAP of annual generation and DR resources did not clear in the auction. Any remaining amount that did not clear was winter only where there were no summer-only resources that did not clear.

Table 3. Offered and Cleared MWs and Associated Prices by LDA

LDA	MW (UCAP)		System Marginal Price	Locational Price Adder***	RCP for Capacity Performance Resources
	Offered MW*	Cleared MW**			
ATSI	7,791.9	7,764.9	$269.92	$0.00	$269.92
ATSI-CLEVELAND	1,615.5	1,614.0	$269.92	$0.00	$269.92
COMED	22,524.4	21,813.9	$269.92	$0.00	$269.92
DAY	493.1	488.6	$269.92	$0.00	$269.92
DEOK	1,639.5	1,633.8	$269.92	$0.00	$269.92
DOM	20,100.2	20,049.6	$269.92	$174.34	$444.26
MAAC	51,529.4	51,303.2	$269.92	$0.00	$269.92
PPL	8,785.1	8,757.6	$269.92	$0.00	$269.92
EMAAC	24,478.2	24,373.3	$269.92	$0.00	$269.92
DPL-SOUTH	960.4	956.9	$269.92	$0.00	$269.92
PSEG	4,446.5	4,390.3	$269.92	$0.00	$269.92
PS-NORTH	2,536.4	2,507.4	$269.92	$0.00	$269.92
SWMAAC	5,089.1	5,060.8	$269.92	$0.00	$269.92
BGE	612.9	606.9	$269.92	$196.43	$466.35
PEPCO	2,285.5	2,263.2	$269.92	$0.00	$269.92
RTO	137,152.1	135,684.0	$269.92	$0.00	$269.92

** Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.*
*** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA.*
**** Locational Price Adder is with respect to the immediate parent LDA*

As seen in Figure 2, the 2025/2026 BRA procured 110.3 MW of capacity from new generation and 753.8 MW from uprates to existing or planned generation. The quantity of new generation is down from the previous BRA where there was 328.5 MW of new generation. The quantity of capacity procured from external Generation Capacity Resources in the 2025/2026 BRA is 1,268.5 MW. All external generation capacity that cleared in the 2025/2026 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2025/2026 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2025/2026 BRA is 6,064.7 MW, and the total quantity of EE procured in the 2025/2026 BRA is 1,459.8 MW.

Figure 2. Cleared MWs (UCAP) by New Generation/Uprates/Imports by Delivery Year

Table 4 contains a summary of the RTO resources for each cleared BRA from 2015/2016 through the 2025/2026 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 195,853.1 MW of ICAP was eligible to be offered into the 2025/2026 Base Residual Auction or used in an FRR Capacity Plan. The total amount of supply in PJM decreased from 202,376.6 MW ICAP to only 195,853.1 MW ICAP, or a decline in the total amount of supply by 6,523.5 MW ICAP. Since this comparison is in ICAP and includes total eligible capacity for both FRR and RPM, it is not impacted by the CIFP capacity accreditation changes or the addition of Dominion load into RPM.

[1] A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a capacity market seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of CIL as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of CIL.

A total of 171,324.3 MW (ICAP) of generation and Demand Response capacity was offered into the Base Residual Auction. This is an increase of 17,262 MW from that which was offered into the 2024/2025 BRA and was driven by the return of Dominion to RPM from FRR. The total DR offered into the auction significantly declined from 9321.1 MW ICAP to 8009.7 MW ICAP. EE resources are considered to be included in the forecast and therefore do not contribute to meeting the reliability requirement. A total of 24,528.8 MW (ICAP) was eligible, but not offered due to (1) inclusion in an FRR Capacity Plan; (2) export of the resource; (3) excused from offering into the auction; (4) Deactivated; or (5) not required to offer into the auction and elected to not offer into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests or external sale of capacity. Resources with approved removal of capacity status requests also did not have a capacity must offer requirement.

Table 4. Total RTO Resources (RPM + FRR) Offered vs Unoffered by Resource Type Used To Meet the Reliability Requirement

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Auction Supply	Delivery Year *(All values in ICAP)*										
	2015/16*	2016/17**	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26***
Internal PJM Gen Capacity	187,407.7	193,052.5	190,333.2	191,322.3	195,203.0	197,804.7	198,726.6	193,412.2	189,704.7	191,133.4	186,134.2
Internal PJM DR+PRD Capacity	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	8,245.5	10,694.8	9,501.2	9,517.2	9,626.1	8,233.7
Imports Offered	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5	4,725.0	1,649.1	1,601.2	1,617.1	1,485.2
Eligible RPM Capacity	211,301.0	215,397.6	207,489.3	207,819.7	210,883.6	211,490.7	214,146.4	204,562.5	200,823.1	202,376.6	195,853.1
Exports/ Delistings	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8	1,319.8	1,525.3	1,518.9	1,522.7	1,525.3
FRR Commitments	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6	13,657.4	33,297.1	33,500.7	34,584.2	13,184.5
Excused	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	8,384.4	9,433.8	2,190.0	9,949.6	12,207.4	9,819.0
Total Eligible RPM Capacity: Excused	25,929.6	25,319.4	21,304.6	19,454.8	18,158.0	23,635.8	24,411.0	37,012.4	44,969.2	48,314.3	24,528.8
Remaining Eligible RPM Capacity	185,371.4	190,078.2	186,184.7	188,364.9	192,725.6	187,854.9	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3
Generation Offered	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1	178,823.5	157,872.2	146,571.7	144,741.2	163,314.6
DR Offered	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8	10,911.9	9,677.9	9,282.2	9,321.1	8,009.7
Total Eligible RPM Capacity: Offered	185,371.4	190,078.2	186,184.7	188,364.9	192,725.6	187,854.9	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3

*Note: *includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; **includes EKPC zone; ***includes DOM zone load previously under the FRR Alternative.*

Table 5 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Until the 2025/2026 Delivery Year, participants' sell offers for thermal resource EFORd values were used to convert a resource's installed capacity (ICAP) values into unforced capacity (UCAP) values. Effective for 2025/2026, the appropriate Accredited UCAP Factor will be used to convert installed capacity (ICAP) values into unforced capacity (UCAP) values. Prior to the 2025/2026 Delivery Year, DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR). Beginning in 2025/2026, DR sell offers are converted into UCAP using the appropriate DR Accredited UCAP Factor while EE sell offers remain as in prior years, by multiplying the EE nominated value by the Forecast Pool Requirement.

Total offered Gen and DR (UCAP) used to meet the reliability requirement declined from 148,945.7 MW to 135,692.3 MW. Please note that UCAP for Delivery Years prior to 2025/2026 were not calculated using the marginal ELCC methodology, and these changes are in part responsible for the year-over-year decrease in offered and cleared UCAP.

Table 5. Capacity Resource Offered and Cleared by Type by Delivery Year (UCAP)

		Delivery Year										
	Auction Results	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21*	2021/22	2022/23	2023/24	2024/25	2025/26
Offered	Generation	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3	171,663.2	152,128.6	141,026.7	138,799.3	129,607.5
	DR	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7	11,886.8	10,513.0	10,116.7	10,146.4	6,084.8
	Total GEN/DR Offered	177,647.4	183,223.2	177,498.5	178,585.1	183,889.2	181,109.0	183,550.0	162,641.6	151,143.4	148,945.7	135,692.3
	EE	940.3	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5	2,954.8	5,056.8	5,471.1	8,417.0	1,459.8
Cleared	Generation	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5	150,385.0	131,541.6	131,777.4	132,423.1	128,607.5
	DR	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4	11,125.8	8,811.9	8,096.2	7,992.7	6,064.7
	Total GEN/DR Cleared	163,638.7	168,042.4	165,664.8	165,590.4	165,790.8	163,796.9	161,510.8	140,353.5	139,873.6	140,415.8	134,672.2
	EE	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2	2,832.0	4,810.6	5,471.1	7,668.7	1,459.8
	Uncleared GEN/DR	14,008.7	15,180.8	11,833.7	12,994.7	18,098.4	17,312.1	22,039.2	22,288.1	11,269.8	8,529.9	1,020.1

Note: RTO numbers include all LDAs. UCAP calculated using ELCC values for Generation Resources. DR and EE UCAP values include appropriate DR AUCAP Factor and FPR.
**Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.*

The 2025/2026 numbers in Tables 6 and 7 have been significantly impacted by the marginal ELCC accreditation changes so it is difficult to simply compare delivery year over delivery year results. Table 6 shows the offered and cleared megawatts by Resource type for RPM plus FRR commitments over the last four delivery years. Since Energy Efficiency is already included in the load forecast, it is not used to meet the Reliability Requirement and therefore separated from the Grand Totals in the tables to provide a more accurate picture of the Resources that will be used to meet the Reliability Requirement.

Table 6. Offered and Cleared MWs by Type for RPM and Committed FRR for Previous BRAs

Offered and Cleared UCAP

	2022/23		2023/24		2024/25		2025/26 (Reflects ELCC Accreditation)	
Type	**Offered**	**Cleared**	**Offered**	**Cleared**	**Offered**	**Cleared**	**Offered**	**Cleared**
Coal	45,754	39,230	37,164	31,811	35,114	31,532	30,081	30,081
Distillate Oil (No.2)	3,178	2,897	2,894	2,855	2,776	2,674	2,408	2,408
Gas	85,562	79,329	85,217	81,643	85,469	83,258	66,354	66,354
Nuclear	31,944	26,140	31,960	31,960	31,835	31,629	30,549	30,549
Oil	2,674	2,527	2,350	2,269	2,493	2,220	578	578
Solar	2,633	2,096	2,945	2,935	4,234	4,232	1,337	1,337
Water	6,917	6,749	6,375	6,375	6,137	6,137	5,365	5,361
Wind	2,595	1,839	1,608	1,416	1,396	1,396	2,618	1,676
Battery/Hybrid	-	-	16	16	36	36	14	14
Other	1,205	1,168	1,185	1,185	1,153	1,153	911	911
Demand Response	10,604	8,903	10,652	8,631	10,334	8,180	6,363	6,342
Aggregate Resource	484	386	511	511	503	503	327	273
Total (without EE)	**193,551**	**171,263**	**182,875**	**171,605**	**181,481**	**172,951**	**146,905**	**145,883**
Energy Efficiency	5,057	4,811	5,471	5,471	8,417	7,669	1,460	1,460
Total (with EE)	198,608	176,073	188,346	177,076	189,898	180,620	148,364	147,343

*The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY plus the UCAP MW committed to FRR Capacity Plans. Notes: Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers. Other consist of: Kerosene, Other Gas, Other Liquid, Other Solid, Wood. *Starting in 2020/2021, Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance*

Capacity Import Participation

Table 7 shows the quantity of capacity imports cleared in the 2025/2026 BRA at 1,268.5 MW (UCAP). The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared are Prior CIL Exception External Resources that qualify for an exception for the 2025/2026 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 7. Capacity Imports (UCAP) Offered and Cleared by Region

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)*	233.7	0.0	570.3	227.2	237.3	1,268.5
Cleared MW (UCAP)*	233.7	0.0	570.3	227.2	237.3	1,268.5
Resource Clearing Price ($/MW-day)	$269.97	$269.97	$269.97	$269.97	$269.97	

**Offered and Cleared MW quantities include resources that received CIL Exception and those associated with pre-OATT grandfathered transmission. Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.*

Resource Type Participation

Table 8 provides a breakdown of the offered and cleared megawatts by season by Resource Type. There were 448 MW of Summer capability and 1,447.4 MW of Winter capability offered in the auction. All 448 MW of Summer resources were matched with Winter resources to meet the annual Capacity Performance capability requirement.

Table 8. Offered and Cleared (UCAP) by Resource Type by Season

	Capacity Performance					
	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
GEN	128,115.1	45.0	1,447.4	128,114.5	45.0	448.0
DR	5,963.8	122.3	-	5,942.4	122.3	-
EE	1,179.1	280.7	-	1,179.1	280.7	-
PRD	210.2	-	-	210.2	-	-
Grand Total	135,468.2	448.0	1,447.4	135,446.2	448.0	448.0

Figure 3 displays the trend in offered and cleared DR and PRD and cleared EE by Delivery Year. Both DR and EE offered and cleared amounts declined significantly for 2025/2026, particularly for EE, which declined by 6,209 MW from the previous year. The amount of PRD remains small and declined slightly in the 2025/2026 Delivery Year.

Figure 3. DR and PRD Offered and Cleared and EE Cleared MW(UCAP) by Delivery Year

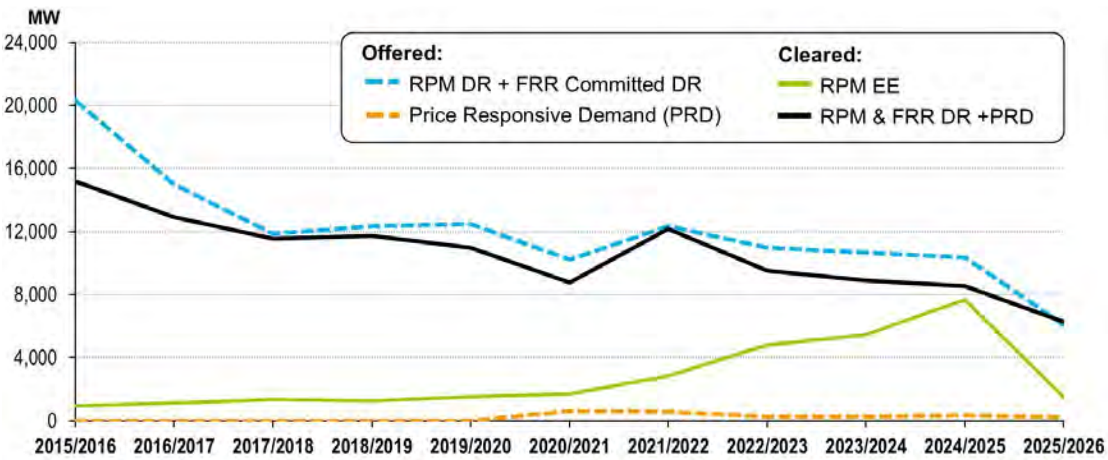

Table 9 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (1,424.5 MW), followed by AEP (1,055.7 MW) and then DOM (827.7 MW).

Table 9. DR and EE Offered and Cleared by LDA

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	*AECO*	44.7	17.5	62.2	40.9	17.5	58.4
EMAAC/DPL-S	*DPL*	117.3	32.7	150.0	117.3	32.7	150.0
EMAAC	*JCPL*	104.8	52.7	157.5	100.7	52.7	153.4
EMAAC	*PECO*	296.4	137.8	434.2	292.6	137.8	430.4
PSEG/PS-N	*PSEG*	237.3	167.2	404.5	228.9	167.2	396.1
EMAAC	*RECO*	2.3	2.2	4.5	2.3	2.2	4.5
EMAAC Sub Total		802.8	410.1	1,212.9	782.7	410.1	1,192.8
PEPCO	*PEPCO*	132.5	80.0	212.5	132.5	80.0	212.5
BGE	*BGE*	163.0	71.8	234.8	163.0	71.8	234.8
MAAC	*METED*	136.0	21.8	157.8	136.0	21.8	157.8
MAAC	*PENELEC*	208.2	17.7	225.9	208.2	17.7	225.9
PPL	*PPL*	422.5	45.7	468.2	422.5	45.7	468.2
MAAC** Sub Total		1,865.0	647.1	2,512.1	1,844.9	647.1	2,492.0
RTO	*AEP*	926.2	129.5	1,055.7	926.2	129.5	1,055.7
RTO	*APS*	478.9	60.8	539.7	478.9	60.8	539.7
ATSI/ATSI-C	*ATSI*	546.1	68.5	614.6	546.1	68.5	614.6
COMED	*COMED*	1,086.9	337.6	1,424.5	1,086.9	337.6	1,424.5
DAY	*DAY*	140.1	18.5	158.6	140.1	18.5	158.6
DEOK	*DEOK*	159.6	24.9	184.5	159.6	24.9	184.5
RTO	*DOM*	673.5	154.2	827.7	673.5	154.2	827.7
RTO	*DUQ*	86.9	18.7	105.6	86.9	18.7	105.6
RTO	*EKPC*	121.6	-	121.6	121.6	-	121.6
Grand Total		6,084.8	1,459.8	7,544.6	6,064.7	1,459.8	7,524.5

** MW values include both Annual and Summer-Period Capacity Performance DR and EE*
*** MAAC sub-total includes all MAAC Zones*

Price Responsive Demand Participation

210.2 MW (UCAP) of PRD was elected and committed in the 2025/2026 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to energy wholesale prices. In the PJM capacity market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system that indicates the Nominal PRD Value in megawatts that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. The Planning Parameters includes a breakdown of elected PRD in ICAP, which can be converted to UCAP by taking ICAP * FPR. The breakdown of PRD UCAP that elected and committed is: 126.7 MW in the BGE LDA, 70.4 MW in the PEPCO LDA, and 13.1 MW in the rest of EMAAC LDA. The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the delivery year.

Table 10. PRD UCAP Committed

PRD UCAP Committed (MW)

Zone/LDA Location			
BGE	PEPCO	EMAAC	Total
126.7	70.4	13.1	210.2

Exhibit A

Benchmark Study Demonstrating that the Inter-Company Power Agreement Offers Low-Cost Power

At the request of the Ohio Valley Electric Corporation ("OVEC"), American Electric Power Service Corporation ("AEPSC") performed a benchmark study in support of the proposed 14-year extension of the term of the Inter-Company Power Agreement ("ICPA"), originally dated July 10, 1953 and as amended from time to time, among OVEC and the public utilities named therein as "Sponsoring Companies," which include several affiliates of AEPSC. As discussed below, it is clear the ICPA offers low-cost power to the Sponsoring Companies, taking into account both price and non-price factors.

A. Definition of the Relevant Market, Time Period and Products.

1. Relevant Geographic Market

Under Commission precedent, the relevant geographic market is the market where sellers can supply the relevant product to the purchasers under the subject contract.[1] This benchmark study defines the relevant geographic market broadly to include any supplier that is in the reliability regions governed by or under the following: (a) Reliability*First* Corporation ("RFC"), which is a consolidation of the three previous regions East Central Area Reliability Coordination Agreement ("ECAR"), the Mid-Atlantic Area Council ("MAAC") and the Mid-America Interconnected Network ("MAIN"), and (b) Midwest Reliability Organization ("MRO"), which regions collectively include the majority of the service territories of the regional transmission organizations of the PJM Interconnection, LLC ("PJM") and the Midwest Independent Transmission System Operator, Inc. ("MISO").

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1 *Ocean State Power II*, 59 FERC ¶ 61,360 at p. 62,333 (1992) ("*Ocean State*").

2. Contemporaneousness

The Commission defines the relevant period for these purposes as the period during which purchasers made their decisions to contract with the supplier.[2] Consequently, this benchmark study is based on a current forecast of generation alternatives through 2040, consistent with the extension period.

3. Comparable Products

The Commission generally requires that the evidence presented in benchmark studies compares transactions involving goods and services similar to those provided within the proposed transaction.[3] Accordingly, this benchmark study defines the relevant comparison to be the ICPA to the construction of base-load power plants over the same long-term time period, since the construction of a power plant is the most comparable alternative to entering into this long-term power supply agreement.

Other products such as power plant acquisitions and long-term power contracts were not considered comparable products since the proposed extension is for the time period March 14, 2026 through June 30, 2040. Such transactions would be near-term agreements that would not be comparable to an extension period that does not begin until 2026, in part since generally no market exists for offers that would provide beginning or closing dates in this timeframe. Construction start dates for new generation, on the other hand, are generally at the discretion of the purchaser, subject to permitting limitations and vendor availability.

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2 *See Electric Generation LLC*, 99 FERC ¶ 61,307, at p. 22 (2002).

3 *See Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 at p. 62,169 (1991); *Ocean State*, 59 FERC at p. 62,333.

B. Summary of Benchmark Study

The benchmark study consists of a comparison of the IPCA for the extension period to construction of new base-load generation.

1. Costs to Construct New Power Plants

Based on information from the U.S. Energy Information Administration ("EIA") document, "*Table 1. Updated Estimates of Power Plant Capital and Operating Costs*". Release Date: November 2010, supplemented by operational assumptions and cost estimates from AEPSC internal sources, the estimated levelized cost of six different types of newly built central station base-load generation are shown on Schedule 1, page 1. The types of power plants reviewed include a new coal plant with flue gas desulphurization (i.e., "scrubbed"), integrated coal-gasification combined cycle (IGCC), with and without carbon capture and sequestration, advanced nuclear generation, and natural gas combined cycle (CC), with and without carbon sequestration. Other potential generation sources were excluded because they were not considered comparable, for example wind and solar, since they are intermittent, non-dispatchable resources.

As shown in Schedule 1, the installed cost of the comparable new units ranges from $1,003/kW for CC without carbon sequestration to $5,348/kW for IGCC with carbon sequestration. For comparison purposes, a typical annual carrying charge was applied to the estimated installed cost to reflect a reasonable amount for depreciation, taxes, administrative and general costs, and other expenses. Estimated fuel costs were also added, along with assumptions regarding the future average costs of carbon dioxide (CO_2) emissions and the ability of sequestration systems to capture the CO_2. These calculations resulted in average levelized total unit costs, including CO_2 costs, ranging from $106 per MWh for a CC plant without carbon sequestration up to $159.20/MWh for an IGCC plant with carbon sequestration. If CO_2 costs are ignored or assumed to be zero, the alternatives range from $96.53/MWh for a new advance gas combined cycle plant to $122.51 per MWh for an advanced nuclear plant.

As shown on Schedule 1, page 2, the average forecasted cost of the ICPA contract for the period 2011 through 2040 is $84.23/MWh including CO_2 cost and $60.90/MWh excluding CO_2 cost. These forecasts already include all of the carrying and operating costs associated with the planned environmental upgrades, including completion of Flue Gas Desulfurization for all Clifty Creek and Kyger Creek units and Selective Catalytic Reduction for Clifty Creek units 1-5 and Kyger Creek units 1-5.

For the cases including CO_2 costs, the cost of the ICPA is expected to be approximately 21% less than the least expensive alternative, the CC plant without carbon sequestration. For the cases excluding CO_2 costs, the ICPA is expected to be approximately 37% less than the least expensive alternative of the new CC plant.

It is recognized that the above values include the period from 2011 through 2040 for the ICPA even though the current request is for the period March 14, 2026 through June 30, 2040. No adjustments were made to attempt to project a near-term completion date and then "remove" the financial impacts of the new build options and the OVEC extension for the period prior to 2026. In practical terms, any such adjustment would require the implicit assumption that a counter-party could be identified that would be willing to purchase the output of the new plant at the fully-loaded cost in the interim period from the plant completion date until a termination date in 2026.

Likewise, forecasting a completion date for a new build option that did not begin commercial operation until 2026 would require the assumption of an unusual near-term commitment from the purchaser (and the vendor) in the near-term. In addition, this option would include a plant life period for the new-build generation that would extend well beyond the extension period termination of 2040. Presenting the proposed extension and the new build options on a levelized cost of electricity basis makes them comparable and mitigates the need for attempts at such adjustments. In addition, the ICPA analysis includes assumptions for the entire period that would potentially impact the cost in the current ICPA contract period.

One significant benefit of the ICPA is that it is expected to be the least cost alternative whether CO_2 costs are included or not. In comparing the CC without carbon sequestration alternative to the ICPA, the benefit of the ICPA, besides the expected discount indicated, is that the ICPA is not expected to carry the same price uncertainty for the fuel input, coal, as that of the CC plant, based on historic volatility associated with natural gas. Since neither of these options have carbon sequestration capability, the CC plant still carries approximately half the CO_2 emission risks as that associated with the ICPA. Furthermore, if forecasted CO_2 emissions cost are less than that included in this forecast, this result would tend to favor the ICPA even more than indicated above.

In a comparison with an advanced nuclear plant, the OVEC ICPA remains the least expensive option even when CO_2 costs are included. As CO_2 costs become less of a factor, or goes to zero, the ICPA discount becomes more comparable to either the natural gas CC or the advanced nuclear plant. In this case, the ICPA is less costly than the least expensive options identified, a new pulverized coal plant, which would have a similar CO_2 emission risk or the CC plant. Consequently, the ICPA clearly provides the most flexible choice with the highest degree of optionality in that it is the least cost option regardless of future CO_2 costs.

It should be noted further that the valuations contained herein that include CO_2 cost do not include any carbon cost offsets. Many types of proposed carbon programs include allocations of offsets, allowances or other phase-in programs that will reduce the carbon costs, at least in the initial years of such a program. No such assumptions are included in the above comparisons, and if they were, the OVEC extension would appear even more favorable compared with other, less carbon-intensive options.

2. Analysis of Non-Price Terms

The Commission also requires an assessment of non-price terms and conditions.[4] AEPSC performed a comparative analysis of specific non-price terms and conditions where such data was available. Specifically, for power plant sales and new-build power plants, the relevant non-price terms and conditions include: (1) availability, (2) dispatchability, (3) fuel price risk, and (4) project development risk. In general, the ICPA contains favorable non-price terms.

a. Availability

The availability of a power plant is a key measure of the reliability of any generating facility.[5] It is an indicator of the potential of a generating resource to meet load requirements and support system reliability. Availability also is a key contract indicator for measuring performance. The OVEC generating facilities have an excellent record of

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4 *Ocean State*, 59 FERC at p. 62,337.

5 *See Electric Generation, LLC*, 101 FERC ¶ 63,005 (2002).

performance based on availability factors. The availability factor for OVEC's Clifty Creek Plant was 85.0% in 2008, 87.1% in 2009 and 83.8% in 2010, while the availability factor for its Kyger Creek Plant was 85.4% in 2008, 84.3% in 2009 and 84.0% in 2010.

b. Dispatchability

Under the ICPA, the Sponsoring Companies have the right to schedule their proportionate share of the full available capacity and energy output of OVEC's generating facilities, subject to scheduling procedures developed by OVEC's Operating Committee.

c. Fuel Price Risk

Fuel costs associated with OVEC's coal-fired generating facilities may increase over the proposed extension of the term of the ICPA, thereby increasing costs to the Sponsoring Companies. However, with respect to construction of comparable units, the purchasers would be subject to the similar cost increases due to fluctuations in fuel prices.

d. Project Development Risk

The Sponsoring Companies are insulated against development risk under the ICPA, as compared to the new construction option, because the OVEC units have already been built and operating for many years.

C. Conclusion

Based on the benchmark study, the charges under the ICPA compare favorably to data concerning prices obtained through review of comparable information for other new generation base load options. The ICPA offers low-cost power to the Sponsoring Companies, taking into account both price and non-price factors.

Cost and Performance Characteristics of
New Central Station Electricity Generating Technologies

Technology	Online Year	Size (MW)	Lead time (years)	Overnight Cost (2010 $/kW)	Variable O&M (2010 $/MWh)	Fixed O&M (2010 $/kW)	Heat Rate (Btu/kWhr)	Levelized Cost of Electricty (COE) Including CO_2 (2011 $/MWh)	Levelized Cost of Electricty (COE) Excluding CO_2 (2011 $/MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Coal									
Scrubbed Coal New	2013	650	4	$3,167	$4.25	$35.97	8,800	**$122.78**	**$98.45**
IGCC	2013	600	4	$3,565	$6.87	$59.23	8,700	**$137.24**	**$113.17**
IGCC with carbon sequestration	2016	520	4	$5,348	$8.04	$69.30	10,700	**$159.20**	**---**
Nuclear									
Advanced Nuclear	2016	2,236	6	$5,335	$2.04	$88.75	N/A	**$122.51**	**$122.51**
Natural Gas									
Advanced Gas/Oil Combined Cycle (CC)	2012	400	3	$1,003	$3.11	$14.62	6,430	**$106.04**	**$96.53**
Advanced CC with carbon sequestration	2016	340	3	$2,060	$6.45	$30.25	7,525	**$144.73**	**---**

IGCC = Integrated Coal-Gasification Combined Cycle

Note: Information in columns (1) through (8) is based on U.S. Energy Information Administration (EIA), *Table 1. Updated Estimates of Power Plants and Operating Costs* , Release Date: November 2010. Results in columns (9) and (10) are based on this EIA information and AEP internal estimates.

Ohio Valley Electric Corporation
Forecasted Inter-Company Power Agreement (ICPA) Billable Cost Summary
Calendar Years 2011 - 2040

(All dollars in 2011 $000 except where indicated)

	Year														
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Power Production Cost															
Excluding CO_2	$631,114	$605,983	$617,141	$608,778	$597,395	$603,810	$589,464	$589,611	$576,098	$577,863	$568,206	$554,703	$555,728	$544,120	$541,864
Including CO_2	$631,114	$605,983	$617,141	$608,778	$597,395	$603,810	$589,464	$826,552	$794,534	$775,611	$758,160	$737,171	$731,004	$745,364	$766,670
Generation (GWh)	14,737	14,645	14,536	14,752	14,753	14,950	15,108	15,158	15,290	15,185	15,185	15,185	15,185	15,185	15,185

	Year															Total
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2011-2040
Power Production Cost																
Excluding CO_2	$530,713	$528,452	$516,170	$509,683	$505,302	$498,631	$496,214	$487,268	$476,432	$470,607	$464,209	$460,502	$457,885	$452,132	$440,887	$16,056,965
Including CO_2	$784,600	$801,473	$806,423	$815,385	$831,189	$821,065	$815,232	$802,906	$788,726	$779,592	$769,920	$762,974	$757,153	$748,229	$733,847	$22,207,468
Generation (GWh)	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	452,815

Total Levelized Power Production Cost ($/MWh)

Excluding CO_2: **$ 60.90 /MWh**

Including CO_2: **$ 84.23 /MWh**

I&M-U-21052
SC Set 1, Q09

OVEC ANALYSIS

INDIANA MICHIGAN POWER
An AEP Company

Per IURC Rockport 2 Settlement (Cause 45546) and MI IRP settlement (Case No. U-20591):

Modeled a scenario where the Preferred Plan was optimized without OVEC units after 2030

Analysis evaluated two termination alternatives

1. Only I&M exited contract
2. All owners exited contract

Analysis results showed continued operation of the OVEC units is cost-beneficial to rate payers

- Under alternative 1, estimated costs to I&M customers would increase by ~$102M NPV
- Under alternative 2, estimated costs to I&M customers would increase by ~$28M NPV

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
	)	

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
AS OF THE PETITION DATE

[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.

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FirstEnergy Solutions Corp. ("FES") and FirstEnergy Generation, LLC ("FG," and together with FES, "Movants"), debtors in the above-captioned chapter 11 cases (together with their affiliated debtors, the "Debtors"), file this motion (the "Motion") for an order, substantially in the form attached hereto as Exhibit A (the "Order"), authorizing the Debtors to reject a certain multi-party intercompany power purchase agreement. In support of the Motion, the Movants incorporate by reference the *Declaration of Donald R. Schneider in Support of Chapter 11 Petitions and First Day Motions* (the "Schneider First Day Declaration"),[1] the *Declaration of Kevin T. Warvell in Support of the Motion to Reject* (the "Warvell Declaration"), the *Declaration of Judah L. Rose in Support of the Motion to Reject* (the "Rose Declaration"), and the *Declaration of David Gerhardt in Support of the Motion to Reject* (the "Gerhardt Declaration"). The Movants respectfully represent as follows:

JURISDICTION AND VENUE

1. The United States Bankruptcy Court for the Northern District of Ohio (the "Court") has jurisdiction over this matter pursuant to 28 U.S.C. §§ 157 and 1334. This matter is a core proceeding within the meaning of 28 U.S.C. § 157(b)(2).

2. Venue is proper in this district pursuant to 28 U.S.C. §§ 1408 and 1409.

3. The statutory bases for the relief requested in this Motion are sections 105(a), 365, 1107(a), and 1108 of title 11 of the United States Code (the "Bankruptcy Code") and rules 2002, 6006 and 9014 of the Federal Rules of Bankruptcy Procedure.

RELIEF REQUESTED

4. By this Motion, the Movants seek to reject an extraordinarily burdensome executory power purchase agreement, effective as of the Petition Date (defined below). During

[1] Capitalized terms not defined herein are defined in the First Day Declaration.

2017 this contract—combined with nine[2] other power purchase agreements the Movants separately seek to reject—accounted for just approximately 3% of the power FES bought and sold into the wholesale market. Yet movants are losing approximately $12 million per year, and are expected to lose $268 million over the remaining 22 years left on the OVEC ICPA (defined below).

5. The Movants further request that the Court grant the relief requested in this Motion without a further hearing on a final basis if no objection is timely filed and served. If any objection(s) to the Motion is timely and properly filed and served with respect to the multi-party intercompany power purchase agreement, the parties shall attempt to reach a consensual resolution of the objection. If the parties are unable to so resolve any objection, the Debtors request that the Court hear such objection at the final hearing on this Motion.

6. The Movants further request that the Court set the deadline by which time the counterparty to the executory power purchase agreement must file a proof of claim relating to the rejection of the executory power purchase agreement as the later of (a) the claims bar date established in the Debtors' chapter 11 cases and (b) thirty (30) days after the entry of an order granting the relief sought in the instant motion.

Background

7. On March 31, 2018 (the "Petition Date"), each of the Debtors filed a voluntary petition with the Court under chapter 11 of the Bankruptcy Code. The Debtors continue to operate their businesses and manage their property as debtors and debtors-in-possession pursuant to sections 1107(a) and 1108 of the Bankruptcy Code. The Debtors have requested joint administration of these chapter 11 cases pursuant to Bankruptcy Rule 1015(b). The Court has

[2] This includes eight "renewable" energy bundled power purchase agreements and one nonrenewable power purchase agreement.

not appointed a trustee and the Office of the United States Trustee for the Northern District of Ohio (the "US Trustee") has not yet formed any official committees in these chapter 11 cases.

8. Non-Debtor FirstEnergy Corp. ("FE Corp."), an Ohio corporation, is the ultimate parent company for each of the Debtors in these chapter 11 cases and certain of FE Corp.'s non-Debtor affiliates (collectively, "FirstEnergy" or "FirstEnergy Group"). Debtor FirstEnergy Solutions Corp. ("FES"), an Ohio corporation, is the parent company for Debtors FE Aircraft Leasing Corp. ("FEALC"), an Ohio corporation, FirstEnergy Generation, LLC ("FG"), an Ohio limited liability company, and FirstEnergy Nuclear Generation, LLC ("NG"), an Ohio limited liability company. Debtor FG is the parent company for Debtors FirstEnergy Generation Mansfield Unit 1 Corp. ("FGMUC"), an Ohio corporation, and Norton Energy Storage L.L.C. ("NES"), a Delaware limited liability company.[3]

9. FES sells power and provides energy-related products and services to retail and wholesale customers primarily in Illinois, Maryland, Michigan, New Jersey, Ohio, and Pennsylvania.

10. FG owns and operates three fossil generation plants[4], two in Ohio and one in Pennsylvania.[5] Additionally, FG operates the fossil generation plant owned by non-Debtor Bay Shore Power Company.

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[3] FG also owns a 99% limited partnership interest in Nautica Phase 2 Limited Partnership, which has $10 million in outstanding debt.

[4] FG also owns a steam turbine and combustion turbine at the Bay Shore Power Plant in Oregon, OH and a combustion turbine at the Eastlake Plant in Eastlake, OH.

[5] FG owns and operates the W.H. Sammis Plant in Stratton, OH, which is composed of seven units and the West Lorain Plant in Lorain, OH, which is composed of six units that run on heating oil. FG operates the entire Bruce Mansfield Plant in Shippingport, PA, where it owns two of the three units. FG owns approximately 6.17% of Unit 1 of the Bruce Mansfield Plant while approximately 93.83% of Unit 1 is under a leasehold interest.

11. A detailed description of the Debtors' business, capital structure, and the events leading to the chapter 11 cases is fully set forth in the Schneider First Day Declaration filed contemporaneously herewith and incorporated by reference as if fully set forth herein.

I. Overview of the Debtors' Business Operations

12. FES offers energy-related products and services to retail and wholesale customers (the "Customers"). FES provides energy products and services to retail Customers under various provider-of-last-resort ("POLR"), shopping, competitive-bid and non-affiliated contractual obligations. FES also participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, New Jersey and Illinois, competing to: (1) provide retail generation service directly to end users; (2) provide wholesale generation service to utilities, municipalities and co-operatives, which, in turn, resell to end users; and (3) sell power and capacity in the wholesale market.

13. FES, along with its non-debtor, unregulated generation affiliate, Allegheny Energy Supply Company, LLC ("AE Supply"), constitutes FirstEnergy's Competitive Energy Services ("CES") segment. Of FirstEnergy's three reportable operating segments, only the CES segment contains Debtor entities.[6] The CES segment's operating results are derived primarily from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission and ancillary costs and capacity costs charged by regional

[6] FirstEnergy's Regulated Distribution segment distributes electricity to approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York through FirstEnergy's ten non-debtor operating companies. FirstEnergy's Regulated Transmission segment transmits electricity through transmission facilities owned and operated by American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, and certain of FirstEnergy's utilities. FirstEnergy derives its revenue for its Regulated Transmission segment primarily from transmission services provided to load-serving entities pursuant to the PJM Open Access Transmission Tariff.

transmission organizations (each, a "RTO") to deliver energy to the CES segment's Customers, as well as other operating and maintenance costs.

14. FES is party to various contracts (the "RTO Agreements") with RTOs, specifically PJM Interconnection, L.L.C. ("PJM") and the Midcontinent Independent System Operator, Inc. ("MISO"). RTOs are responsible for coordinating, controlling and monitoring a regional high-voltage transmission grid. They administer markets to ensure safe and reliable operation and delivery of electricity. On a real-time basis, the RTO ensures that sufficient generation capacity exists to meet Customers' needs. Through the RTO Agreements, FES has made commitments to use good utility practices to assist the RTOs in meeting their operational commitments. Additionally, RTOs require payment and collateral obligations pursuant to the RTO Agreements. FES collects fees for its generation and pays the RTOs for expenses incurred in serving its Customers. In the event of an energy shortage or capacity failure in the region, PJM or the relevant RTO will pay power providers to remain in operation either by actively producing power or remaining available to offer capacity. As a result of the role RTOs play in administering markets, no reliability concern (and therefore no issue for consumers) is implicated by a breach of the executory power purchase agreements. The counterparties can resell the energy, bring a claim for damages and, in the unlikely event that a breach results in the shutdown of a counterparty, the relevant RTO would step in to prevent a shortage. Since no reliability issue would result from the rejection of the executory power purchase agreements, they are truly no different from any long-term money losing contract.

II. The OVEC Intercompany Power Purchase Agreement

15. FG is a party to a multi-party intercompany power purchase agreement (the "OVEC ICPA,") pursuant to which FES and several other power companies "sponsor" and

purchase power generated by fossil fuel from the Ohio Valley Electric Corporation ("OVEC"). 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. Based on current expectations, FG will lose approximately $268 million on an undiscounted basis over the remaining term of the OVEC ICPA.

16. The Movants can operate their businesses without the OVEC ICPA.

17. None of the Debtors' Customers—or any consumer for that matter—will go without power or capacity if the Movants are permitted to reject the OVEC ICPA. In 2017, the power generated under the OVEC ICPA totaled 0.6 TWh—just 0.1% of the total 767 TWh generated from all power plants selling in PJM. Further, OVEC will be able to sell its power generated for FG to other wholesale purchasers or into the regional wholesale electric spot markets (in this case, the markets operated by PJM).

BASIS FOR RELIEF

18. Section 365(a) of the Bankruptcy Code provides that a debtor-in-possession "subject to the court's approval, may . . . reject any executory contract or unexpired lease of the debtor." 11 U.S.C. § 365(a). "This provision allows a trustee to relieve the bankruptcy estate of burdensome agreements which have not been completely performed." *Stewart Title Guar. Co. v. Old Republic Nat'l Title Co.*, 83 F.3d 735, 741 (5th Cir. 1996) (citing *In re Murexco Petrol., Inc.*, 15 F.3d 60, 62 (5th Cir. 1994)). Bankruptcy courts have broad authority and considerable discretion under this provision. *See Class Five Nev. Claimants v. Dow Corning Corp. (In re Dow Corning Corp.)*, 280 F.3d 648, 656 (6th Cir. 2002).

19. The Supreme Court has recognized that "the authority to reject an executory contract" is not merely incidental, but rather it "is vital to the basic purpose of a Chapter 11 reorganization, because rejection can release the debtor's estate from burdensome obligations

that can impede a successful reorganization." *NLRB v. Bildisco & Bildisco*, 465 U.S. 513, 528 (1984). Courts have similarly held that "[t]he right of a debtor in possession to reject certain contracts is fundamental to the bankruptcy system because it provides a mechanism through which severe financial burdens may be lifted while the debtor attempts to reorganize." *Westbury Real Estate Ventures, Inc. v. Bradlees Stores, Inc. (In re Bradlees Stores, Inc.)*, 194 B.R. 555, 558 n.l (Bankr. S.D.N.Y. 1996). Rejection of an executory contract under 11 U.S.C. § 365(a) constitutes a breach of the contract—not a modification or termination. *Osprey-Troy Officentre, LLC v. World All. Fin. Corp.*, 502 F. App'x 455, 456-57 (6th Cir. 2012); *see also In re N. Am. Royalties, Inc.*, 276 B.R. 860, 865 (Bankr. E.D. Tenn. 2002) ("Rejection is independent of the contract terms.").

20. Rejection is "vital" and "fundamental," because in many cases, the debtor could not emerge from bankruptcy as a going concern if it were forced to specifically perform under burdensome executory contracts. *Leasing Serv. Corp. v. First Tenn. Bank N.A.*, 826 F.2d 434, 436 (6th Cir. 1987) ("Rejection denies the right of the contracting creditor to require the bankrupt estate to specifically perform..."); *see also Midway Motor Lodge of Elk Grove v. Innkeepers Telemgmt. & Equip. Corp.*, 54 F.3d 406, 407 (7th Cir. 1995) ("Rejection avoids specific performance, but the debtor assumes a financial obligation equivalent to damages for breach of contract."); *Bradlees Stores*, 194 B.R. at 558 ("Specific performance should not be permitted where the remedy would in effect do what section 365 meant to avoid, that is, impose burdensome contracts on the debtors.") (quoting *In re Fleishman*, 138 B.R. 641, 648 (Bankr. D. Mass. 1992)).

21. The Bankruptcy Code permits the debtor to breach the burdensome contracts, transforming those obligations into a pre-petition claim for damages, which may be satisfied and

discharged together with all claims against the estate. *See* 11 U.S.C. § 365(g); *see also In re Richendollar*, No. 04-70774, 2007 WL 1039065 (Bankr. N.D. Ohio Mar. 31, 2007) ("The purpose of section 365(g) is to make clear that, under the doctrine of relation back, the other party to a contract that has not been assumed Section 365(g) is simply a general unsecured creditor.") (quoting 3 Collier on Bankruptcy § 365.09[1] (15th ed. 2006).

22. Rejection thereby allows for ratable treatment of a debtors' unsecured lenders/creditors and its counterparties on executory contracts. *In re Albrechts Ohio Inns, Inc.*, 152 B.R. 496, 501–02 (Bankr. S.D. Ohio 1993) (noting the business judgment rule is satisfied for rejection purposes where "rejection will result in benefit to the debtor's general unsecured creditors"). Here, ensuring ratable treatment amongst such parties is essential to an equitable outcome. Requiring the Debtors to perform the remaining up to 22 years of the OVEC ICPA (as opposed to rejection), thereby paying OVEC in full, would be incredibly unfair and inequitable.

A. Rejection of the OVEC ICPA is a Proper Exercise of the Debtors' Business Judgment

23. The "business judgment" standard applies to determine whether the rejection of an executory contract or unexpired lease should be authorized. *See Orion Pictures Corp. v. Showtime Networks, Inc. (In re Orion Pictures Corp.)*, 4 F.3d 1095, 1098-99 (2d Cir. 1993); *see also Bildisco*, 465 U.S. at 524 (acknowledging that business judgment is the "traditional" standard for rejection of executory contracts); *Phar-Mor, Inc. v. Strouss Bldg. Assocs*., 204 B.R. 948, 951-52 (N.D. Ohio 1997) ("Whether an executory contract is 'favorable' or 'unfavorable' is left to the sound business judgment of the debtor."); *In re Fashion Two Twenty, Inc*., 16 B.R. 784, 787 (Bankr. N.D. Ohio 1982) (adopting the business judgment standard as "the proper standard" to determine a motion for rejection).

24. Rejection of an executory contract is appropriate where such rejection would benefit the estate. *See In re Orion Pictures Corp*., 4 F.3d at 1098-99; *Sharon Steel Corp. v. Nat'l Fuel Gas Distrib. Corp*., 872 F.2d 36, 40 (3d Cir. 1989); *In re HQ Glob. Holdings*, 290 B.R. 507, 511 (Bankr. D. Del. 2003); *In re Pesce Baking Co., Inc*., 43 B.R. 949, 956 (Bankr. N.D. Ohio 1984).

25. Thus, upon finding that FG has exercised their sound business judgment in determining that rejection of the OVEC ICPA is in the best interests of the Debtors, their creditors and all parties in interest, the Court should approve the rejection under section 365(a) of the Bankruptcy Code. *See, e.g., In re Level Propane Gases, Inc*., 297 B.R. 503, 509 (Bankr. N.D. Ohio 2003) (granting rejection where debtors "set forth a sound business judgment"), *aff'd*, No. 02-16172, 2007 WL 1821723 (N.D. Ohio June 22, 2007); *In re Fashion Two Twenty, Inc*., 16 B.R. at 787 (same). If a debtor's business judgment has been reasonably exercised, a court should approve the assumption or rejection of an executory contract. *See*, *e.g., Phar-Mor, Inc*., 204 B.R. at 952 ("Courts should generally defer to a debtor's decision whether to reject an executory contract."); *Summit Land Co. v. Allen (In re Summit Land Co.)*, 13 B.R. 310, 315 (Bankr. D. Utah 1981) (holding that absent extraordinary circumstances, court approval of a debtor's decision to assume or reject an executory contract "should be granted as a matter of course").

26. Here, the OVEC ICPA Rejection Motion clearly reflects the sound exercise of the Debtors' business judgment. Under the OVEC ICPA, which is wholly unnecessary for FG's business, the Debtors are today paying more than double the market value of capacity and power, and are expected to for the remaining life of this executory contract. As discussed more fully in the Warvell Declaration, the Debtors and ICF conducted an analysis of the potential business

impact of continuing to perform under the OVEC ICPA and determined that such performance would serve to decimate the Debtors' finances, to the tune of $268 million. The Debtors, assisted by financial advisors at Alvarez & Marsal and energy industry consultants at ICF International, have concluded that without rejection of the OVEC ICPA the Debtors' ability to reorganize would be jeopardized and their estates would be irreparably damaged.

27. The U.S. Court of Appeals for the Fifth Circuit has suggested that rejection of a FERC-regulated contract under section 365 should be subject to a more rigorous standard than the business judgment standard because of the "public interest" in the "transmission and sale of electricity," including "the continuity of electrical service to the customers of public utilities," that is recognized in the Federal Power Act ("FPA"). *Mirant Corp. v. Potomac Elec. Power Co. (In re Mirant Corp.)*, 378 F.3d 511, 525 (5th Cir. 2004) (citing 16 U.S.C. § 824(a)). While the Fifth Circuit correctly decided the core jurisdictional issue (*i.e.*, that FERC-regulated contracts could be rejected in bankruptcy), its suggestion that the bankruptcy court should apply a heightened standard is wrong as a matter of law—especially in the circumstances now before the Court. Moreover, even if the standard outlined in *Mirant* was deemed applicable here, the Movants would easily satisfy it.

28. The Fifth Circuit suggested that a debtor should be required to show that the contract "burdens the estate, that after careful scrutiny, the equities balance in favor of rejecting th[e] power contract, and that rejection of the contract would further the Chapter 11 goal of permitting the successful rehabilitation of debtors." *Id*. (citing *Bildisco*, 465 U.S. at 526-27).

29. There is no basis to apply a more rigorous standard than the business judgment standard to the OVEC ICPA. As explained above, the business judgment standard has long governed the rejection of executory contracts, except in a rare circumstance dictated by

Congressional intent that is not found in the FPA. In *Mirant*, the Fifth Circuit suggested without any basis in precedent that a more rigorous standard should apply to wholesale power contracts by analogizing those contracts to collective bargaining agreements subject to National Labor Relations Board regulation, which the Supreme Court held should be subject to more rigorous scrutiny because of the "special nature of a collective bargaining contract." *In re Mirant Corp.*, 378 F.3d at 524-25 (quoting *Bildisco*, 465 U.S. at 524). In *Bildisco*, however, appellate courts had applied different variations of a heightened standard prior to Congress's enactment of section 365(a), and the Court determined that "Congress intended" a higher standard to apply to collective bargaining contracts. *Bildisco*, 465 U.S. at 525-26. There is no evidence that Congress intended a more rigorous standard to apply to wholesale power contracts. And it is not sufficient to state that FERC-regulated contracts are important—so are many contracts in many important areas of the economy subject to federal regulation that are nonetheless governed by the business judgment standard. *See, e.g.*, *Grp. of Instl. Inv'rs v. Chi., M., St. P. & Pac. R.R. Co.*, 318 U.S. 523, 550 (1943) (railroad); *In re Trans World Airlines, Inc.*, 261 B.R. 103, 123 (Bankr. D. Del. 2001) (aviation); *In re Enron Corp.*, No. 01 B 16034, 2006 WL 898033, at *4 (Bankr. S.D.N.Y. Mar. 24, 2006) (telecom).

30. It is even more doubtful that Congress could have intended a more rigorous standard to apply to rejections by electricity *customers* (such as FES and FG as purchasers under the OVEC ICPA) given that the FPA was enacted to protect such customers, not regulate them—much less force them to continue purchasing electric service they neither need, want, or can afford. *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952) ("A major purpose of the whole [Federal Power] Act is to protect power consumers against excessive prices."); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1017 (9th Cir. 2004) (describing

"protecting consumers" as the FPA's "primary purpose"). In sum, there is no heightened or otherwise different bankruptcy-related standard applying to wholesale electric contracts. Nothing in the text of the FPA states or implies such a standard. No Supreme Court case suggests such a standard. And no case actually *applies* such a standard, as *Mirant* was decided on other grounds on remand.

31. Even if the Court determined that the heightened standard suggested by the Fifth Circuit should apply, however, Debtors would clearly meet it. The OVEC ICPA is extremely burdensome to Debtors' estates, and the cost of continuing to perform under it would threaten the viability of Debtors' restructuring efforts. And importantly, the public interest in "continuity of electrical service" is not implicated by rejection of the OVEC ICPA because rejection would not "cause any disruption in the supply of electricity to other public utilities or to consumers." *In re Mirant*, 378 F.3d at 525. As noted above, FES and FG are not electric suppliers under the OVEC ICPA; they are customers. Their rejection of the OVEC ICPA therefore will not cause any "disruption in the supply of electricity" because FES and FG do not supply electricity under these contracts in the first instance. Put simply, no customers will have their power supply threatened as a result of the Movants' rejection of the OVEC ICPA.

32. Rejection of the OVEC ICPA will relieve the Movants of the near term losses of approximately $12 million on an annual average basis (2018 to 2023) and will eliminate the approximately $268 million in continuing losses over the remaining life of the contracts. Rejection of the OVEC ICPA is thus a sound exercise of the Movants' business judgment and will benefit the Debtors' estates and their creditors.

B. This Court Should Grant the Requested Relief *Nunc Pro Tunc*

33. The Movants request that the Court deem the rejection, if granted, to have retroactive effect to the date of the filing of this Motion on April 1, 2018. Under section 105 of

the Bankruptcy Code, the Court has expansive equitable powers to fashion any order or decree that is necessary to carry out the provisions of the Bankruptcy Code. 11 U.S.C. § 105(a). This includes a grant of *nunc pro tunc* relief on a debtor's motion to reject a lease, when such relief is equitable. *EOP-Colonnade of Dall. LP v. Faulkner (In re Stonebridge Techs., Inc.)*, 430 F.3d 260, 273 (5th Cir. 2005) (noting that "most courts have held that lease rejection may be retroactively applied"); *Pac. Shores Dev., LLC v. At Home Corp. (In re At Home Corp.)*, 392 F.3d 1064, 1071-72 (9th Cir. 2004) (affirming bankruptcy court's exercise of its equitable authority to approve retroactive rejection under section 365); *Thinking Machs. Corp. v. Mellon Fin. Servs. Corp. # 1 (In re Thinking Machs. Corp.)*, 67 F.3d 1021, 1028 (1st Cir. 1995) (recognizing that bankruptcy courts have discretion to approve rejection retroactive under section 365 "when the balance of the equities preponderates in favor of such remediation"); *see also In re QSL Medina, Inc.*, No. 15-52722 (AMK) (Bankr. N.D. Ohio Dec. 15, 2015), ECF No. 105 (authorizing rejection effective as of the petition date).

34. Courts determine whether retroactive effect is appropriate on a case-by case basis. *See In re Thinking Machs. Corp*., 67 F.3d at 1029 n.9 ("[W]e eschew any attempt to spell out the range of circumstances that might justify the use of a bankruptcy court's equitable powers in this fashion. That exercise is best handled on a case-by-case basis.").

35. Here, equitable considerations support the retroactive rejection of the OVEC ICPA effective as of the Petition Date. First, the Court's decision whether to grant rejection on a *nunc pro tunc* basis has potentially significant consequences to the Debtors' estates. Performance under unprofitable, non-essential contracts such as the OVEC ICPA, for any period of time, even for a few months at a loss of about $1 million per month in the near term, will hamper the Debtors' efforts to maximize value and pursue a successful emergence from chapter

11. The Movants' continued performance under the OVEC ICPA would pose a substantial threat to a successful restructuring of the Debtors.

36. Finally, the Movants have not delayed in seeking to reject the OVEC ICPA, but moved for rejection immediately upon filing for chapter 11 relief. These facts support granting retroactive relief. *In re At Home Corp*., 392 F.3d at 1072-73 (granting retroactive effect in part because debtor filed its motion on the first day of the case and scheduled the hearing for the "earliest practicable date"). There is no legitimate basis for delaying rejection, and OVEC will suffer no material prejudice from a grant of retroactive relief.

RESERVATION OF RIGHTS

37. Nothing contained in this Motion or any actions taken by the Debtors pursuant to the relief granted in the Order is intended or should be construed as: (a) an admission as to the validity of any particular claim against a Debtor entity; (b) a waiver of the Debtors' rights to dispute any particular claim on any grounds; (c) a promise or requirement to pay any particular claim; (d) an implication or admission that any particular claim is of a type specified or defined in this Motion; (e) a request or authorization to assume any agreement, contract, or lease pursuant to 11 U.S.C. § 365; or (f) a waiver or limitation of any of Debtors' rights under the Bankruptcy Code or any other applicable law.

NOTICE

38. No trustee, examiner or official committee has been appointed in the Debtors' chapter 11 cases. Notice of this Motion has been served on the following parties and/or their counsel, if known, via facsimile, overnight delivery, regular U.S. Mail, e-mail, and/or hand delivery: (a) the Office of the U.S. Trustee for the Northern District of Ohio; (b) the entities listed on the Consolidated List of Creditors Holding the 50 Largest Unsecured Claims filed pursuant to Bankruptcy Rule 1007(d); (c) counsel to the Bank of New York Mellon Trust

Company, N.A., in its capacity as indenture trustee under various indenture agreements; (d) counsel to UMB Bank, National Association, in its capacity as indenture trustee, paying agent, and collateral trustee under various indenture agreements, including, without limitation, certain pollution control revenue bond indentures and certain first mortgage bond indentures, and trust agreements; (e) counsel to Wilmington Savings Fund Society, FSB, in its capacity as indenture trustee and pass through trustee under various indenture agreements and trust agreements in connection with the Bruce Mansfield Unit 1 sale-leaseback; (f) counsel to the Ad Hoc Group of Holders of the 6.85% Pass Through Certificates due 2034; (g) counsel to the ad hoc group of certain holders of (i) pollution control revenue bonds supported by notes issued by FG and NG and (ii) certain unsecured notes issued by FES (collectively, the "Ad Hoc Noteholder Group"); (h) counsel to FirstEnergy Corp.; (i) counsel to MetLife Capital, Limited Partnership; (j) the District Director of the Internal Revenue Service; (k) the Securities and Exchange Commission; (l) the Office of the United States Attorney for the Northern District of Ohio; (m) the United States Environmental Protection Agency; (n) the Nuclear Regulatory Commission; (o) the United States Department of Energy; (p) the Federal Energy Regulatory Commission; (q) the Office of the Attorney General for Ohio; (r) the Office of the Attorney General for Pennsylvania; (s) the Office of the Attorney General for Illinois; (t) the Office of the Attorney General for Maryland; (u) the Office of the Attorney General for Michigan; (v) the Office of the Attorney General for New Jersey; (w) the National Association of Attorneys General; and (x) the Ohio Valley Electric Corporation. The Debtors submit that, in light of the nature of the relief requested, no other or further notice need be given.

CONCLUSION

WHEREFORE, the Movants respectfully request that the Court enter an order granting the relief requested by this Motion and such further relief as may be just and necessary under the circumstances.

Dated: April 1, 2018

Respectfully submitted,

/s/ Marc B. Merklin

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Proposed Counsel for Debtors
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**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
	)	

[PROPOSED] ORDER (I) AUTHORIZING THE DEBTORS TO REJECT CERTAIN A CERTAIN MULTI-PARTY INTERCOMPANY POWER PURCHASE AGREEMENT WITH THE OHIO VALLEY ELECTRIC CORPORATION *NUNC PRO TUNC* TO THE PETITION DATE AND (II) GRANTING CERTAIN RELATED RELIEF

Upon the motion of FirstEnergy Solutions Corp. ("FES") and FirstEnergy Generation, LLC ("FG,"), debtors in the above-captioned chapter 11 cases (together with their affiliated debtors the "Debtors"), for the entry of the Proposed Order (i) authorizing and approving the rejection, *nunc pro tunc* to the date of commencement of these chapter 11 cases, of a certain multi-party intercompany power purchase agreement with the Ohio Valley Electric Corporation (the "OVEC ICPA") and (ii) granting related relief; and the Court having jurisdiction to consider the motion and the relief requested therein in accordance with 28 U.S.C. § 1334; and consideration of the motion and the relief requested therein being a core proceeding in accordance with 28 U.S.C. §§ 157(b)(2); and venue being proper in this jurisdiction pursuant to

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[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.

28 U.S.C. §§ 1408 and 1409; and due and proper notice of the motion being adequate and appropriate under the particular circumstances; and a hearing having been held to consider the relief requested in the motion; and upon the First Day Declaration, the record of the hearing and all proceedings had before the Court; and the Court having found and determined that the relief sought in the motion is in the best interests of the Debtors' estates, their creditors, and other parties in interest, and that the legal and factual bases set forth in the motion establish just cause for the relief granted herein; and any objections to the requested relief having been withdrawn or overruled on the merits; and after due deliberation and sufficient cause appearing therefor, it is hereby **ORDERED**:

1. The motion is granted to the extent set forth herein.

2. The OVEC ICPA is hereby rejected. Such rejection shall be effective *nunc pro tunc* to the Petition Date.

3. Any claims based on the rejection of the OVEC ICPA shall be filed in accordance with any applicable order establishing a bar date for filing proofs of claim in these cases, to be established by the Court at a later date.

4. Notwithstanding the relief granted herein and any actions taken hereunder, nothing contained in this Order shall constitute, nor is it intended to constitute, an admission as to the validity or priority of any claim against the Debtors, the creation of an administrative priority claim on account of the pre-petition obligations sought to be paid, or the assumption or adoption of any contract or agreement under Bankruptcy Code section 365.

5. Notice of the motion as provided herein shall be deemed good and sufficient and such notice satisfies the requirements of Bankruptcy Rule 6004(a) and the Local Rules.

6. Notwithstanding the possible applicability of Bankruptcy Rule 6004(h), this order shall be immediately effective and enforceable upon its entry.

7. The Debtors are authorized to take all actions necessary to effectuate the relief granted pursuant to this order.

SUBMITTED BY:

/s/ ____________________________

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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

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
13 December 2018

Update

Rate this Research

RATINGS

Ohio Valley Electric Corp

Domicile	Piketon, Ohio, United States
Long Term Rating	Ba1
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ohio Valley Electric Corp

Update following ratings affirmation with stable outlook

Summary

Ohio Valley Electric Corporation's (OVEC) credit profile reflects the governing provisions of its long-term Inter-Company Power Agreement (ICPA) between thirteen investor-owned and cooperative utility companies (collectively, the sponsors), one of which is currently in default. Our view considers the steps taken by management and the remaining sponsors to mitigate the financial impact of the small (under 5% of revenues) defaulting sponsor as well as the overall credit quality of the sponsor group.

Under the ICPA, the sponsors pay monthly demand and transmission charges designed to cover all non- fuel related costs of owning, operating, and maintaining electric generation and transmission facilities, including debt service, irrespective of plant availability or usage. Fuel related costs are recovered through a volumetric energy charge. We currently view the sponsors' overall average credit profile to be investment grade; however, the sponsor obligations are several – not joint, which in the context of our rating methodology for US Municipal Joint Action Agencies, limits our view of their collective credit quality and caps the score for this factor at two notches above the "weakest link". Since the ICPA currently does not include a requirement for non-defaulting sponsors to "step-up" their payments in the event of a default, the weakest link is the sponsor with the lowest credit quality, First Energy Solutions Corp. (FES, unrated), which contributes under 5% of non-fuel related costs (approximately $17 million per year) and is currently in default.

Despite the limitation on methodology factor scoring noted above, our view of OVEC's overall credit profile considers the financial strength of the majority of its sponsors, which are predominately investment grade utilities, the mitigating actions taken by OVEC and the sponsors in response to the current default, and the small, manageable, size of that default. Actions taken include the ongoing funding of a debt reserve at a rate of $2.4 million per month, and the retention of earnings that could be used to offset future payment shortfalls.

Credit strengths

» Effective management of sponsor default and bankruptcy

» Fixed and variable costs, including debt service, are recovered through a strong ownership contract, albeit with a flaw

» Primarily investment grade sponsors/off-takers

» Diminished regulatory uncertainty for Ohio based utility sponsors

Credit challenges

» Sponsor obligations that are several and not joint

» Bankruptcy and subsequent payment default by one sponsor company representing about 5% of revenues

» Weak credit quality of a second merchant power sponsor company, representing about 3% of revenues, which has divested all its non-OVEC generating assets

» Challenging competitive conditions arising from current low prices for natural gas and power

» Constrained liquidity with bank credit facility due within one year

» Elevated carbon transition risk

Rating outlook

The stable outlook recognizes the credit quality of OVEC's non-defaulting sponsors, and the company's actions to address the limited financial impact of the current, ongoing, default. The outlook assumes payment shortfalls will continue to be addressed with excess operating cash, existing reserves, or via short-term borrowing. The outlook assumes OVEC will continue to collect reserve funds at the current rate at least until it has accumulated a full year of debt service (currently about 45% funded), and that it will extend the maturity of its revolving credit facility well in advance of its current November 2019 termination date.

Factors that could lead to an upgrade

» Rating upgrades are unlikely over the near-term

» Credit supportive changes to the ICPA, such as an inclusion of a step-up provision

» Longer term, an improvement in the overall credit profile of the sponsor group

» Stronger financial metrics, including a debt service coverage ratio above 1.6x

Factors that could lead to a downgrade

» An inability or unwillingness to continue collecting reserve or excess operating funds sufficient to cover payment shortfalls

» Failure to extend OVEC's revolving credit facility beyond its 2019 termination date by early 2019

» Further declines in the credit quality of any sponsors

» A sponsor payment default that was not able to be covered by existing reserves or through a swift replacement of the defaulting party

Profile

OVEC owns and operates two coal-fired generating power plants, Kyger Creek in Ohio and Clifty Creek in Indiana, that have a combined capacity of approximately 2,400 MW. OVEC is sponsored by nine investor-owned regulated electric utilities, two independent generating companies (subsidiaries of a utility holding company) and two affiliates of generation and transmission cooperatives (collectively, the sponsors). By virtue of their ownership, the sponsors purchase OVEC's power at wholesale, cost based, rates. The ownership structure is governed by a long-term Inter-Company Power Agreement (ICPA) expiring in 2040. OVEC's fuel, operating, capital and debt service requirements costs are passed-through to the sponsors pursuant to the ICPA. The sponsors participate in the management and financial planning of OVEC through the OVEC Board of Directors, and a long-standing management and services agreement with American Electric Power Company Inc. (AEP: Baa1 stable).

Detailed credit considerations

Effective management of the bankruptcy and subsequent payment default by one sponsor company representing about 5% of revenues

In March 2018, FES filed for Chapter 11 bankruptcy protection, sought to reject the ICPA, and stopped paying its approximately 5% share of OVEC's costs. In July 2018, the bankruptcy court granted FES's motion to reject the contract based on a "business judgment" rather than a "public interest" standard. OVEC is currently challenging the bankruptcy court's approval of FES' rejection of the ICPA, as well as the court's decision to bar the Federal Energy Regulatory Commission (FERC) from the process. OVEC's challenges have been accepted for review by the United States Court of appeals for the Sixth Circuit. In the meantime, OVEC has filed a rejection damages claim of approximately $540 million against FES. Any damage awards could be used to offset future FES obligations, and for debt repayment.

Following rejection of the ICPA, the FES share of energy and capacity has been allocated to the other sponsors, who have been paying their share of OVEC's variable costs; however, no one has "stepped-up" for FES' share of OVEC's fixed cost obligations. We estimate FES' share of OVEC's fixed costs to be approximately $17 million per year. In sensitivity testing taking into account FES' share of energy and capacity revenues that are being paid, we estimate the shortfall could be reduced to about $10-$13 million per year; however these revenues are currently being allocated to the non-defaulting sponsors. As such, OVEC is currently bearing the entire cost of the shortfall, illustrating the exposure created by the lack of step-up provision in the current ICPA.

Fortunately for OVEC, the shortfall created by the FES default is relatively modest and, as there was ample warning of FES' impending default, management was able to take steps to mitigate its impact. These steps include funding a debt reserve at a rate of about $30 million per year (current balance is about $60 million), and the retention of the return on equity portion of its rates (approximately $2.5 million per year) as a cushion. This equity cushion would be sufficient to cover future FES shortfalls in the event the current FES shortfall is covered by short-term borrowing.

To date, there have been no draws from the debt reserve, and as of September 30, 2018, OVEC had $60 million of unrestricted cash on hand. In addition to the debt reserve, OVEC's long-term investments include about $70 million received as part of a prior settlement with the Department of Energy (DOE) that could be utilized to cover future shortfalls. The DOE funds had been ear-marked as a source of funding for future postretirement benefits; however OVEC has the ability to include a postretirement benefits charge in the fixed costs billed to the sponsors. This liquidity provides sufficient near term coverage for the FES shortfall, and we expect the sponsors will continue to work toward implementing a longer term solution, including potential credit enhancing improvements to the ICPA, after there is resolution of the issues surrounding the FES bankruptcy.

While it has not filed for bankruptcy, FirstEnergy Corp.'s (FirstEnergy: Baa3, stable) other merchant subsidiary, Allegheny Energy Supply (AES, not rated) (3% of revenues) recently sold all of its non-OVEC generating assets and repaid all of its debt, leaving the company with very limited independent revenue generating ability. AES is continuing to meet its OVEC obligations, however we estimate its earnings shortfall to be around $5 million per year. AES' share of OVEC's fixed cost is about $10 million per year. As such, if it were also to default, the combined FES and AES shortfalls would still be less than the approximately $30 million per year OVEC is currently collecting as a reserve.

Full cost pass through of costs provided by the ICPA historically offset OVEC's weak financial profile

The ICPA contractually binds the sponsor group to pay a demand charge covering all non-fuel costs incurred by OVEC, including debt service, irrespective of plant availability or whether the sponsors take power from OVEC. Sponsor payments are semi-monthly, which we view positively versus the semi-annual payment of interest, as the timing allows OVEC to build the collection of required debt service before it is due. There is also an energy charge designed to recover all fuel-related costs and is payable based on each sponsor's pro-rata share of electricity volumes.

Prior to June 2016, the sponsors made dispatch decisions independently. If a sponsor decided not to take its allocation of the output, it was offered to the remaining sponsors. If the other sponsors did not choose to take that energy, OVEC did not generate the power. Beginning in 2016, OVEC bids over 90% of its energy into the PJM Interconnection (PJM) market on behalf of all of the sponsors, and its two plants will only generate power to the extent it is economic (dispatched by the system operator). Sponsor companies receive their pro-rata share of energy revenues and pay their pro-rata share of fuel costs.

Following FES' March 2018 bankruptcy filing, and the court's July 2018 acceptance of FES' rejection of the ICPA, FES' share of energy has been taken by the remaining sponsors. The sponsors have accepted their allocations and have been paying their pro-rata share of the related variable production costs, but not fixed costs.

The cost recovery provided by the ICPA helps to offset financial metrics that are weak when viewed in the context of Moody's rating methodology for regulated electric and gas utilities (which applies to the majority of the off-takers). In 2017, cash flow from operations excluding changes in working capital (CFO pre-WC) to debt was about 7.5%, marginally stronger than the 5.0% and 4.1% demonstrated in 2016 and 2015. Within the context of our rating methodology for regulated electric and gas utilities, these metrics are typically reflective of a speculative grade credit profile.

On the other hand, the sponsor take-or-pay type obligations that are created under the ICPA result in a structure that, within our rated universe, is more akin to that of a municipal joint action agency, (albeit with primarily non-municipal participants). As a result, we evaluate OVEC under the US municipal joint action agencies rating methodology (JAA Methodology). It is fairly common for joint action agencies to look to recover their costs with little or no margin. Within the context of the JAA Methodology for take-or-pay projects, a fixed obligation charge coverage ratio in the range of 1.0x-1.6x receives a score of "Baa". For 2017, we calculate OVEC's fixed obligation coverage ratio as 1.23x, and its three year historical average is 1.21x. Going forward, even with the shortfall created by the FES bankruptcy, we expect that OVEC will produce a fixed obligation coverage ratio above 1.0x, incorporating the ongoing debt reserve funding, the metric should remain around 1.2x.

Primarily investment grade credit quality of owner/off-takers

With the exception of FES and AES, we view the remainder of OVEC's sponsors (approximately 92%) as having strong investment grade characteristics. However, as the obligations are several and not joint, within the context of our JAA Methodology scorecard grid, the score for this factor is capped at two notches above the weakest link. Since there currently is no "step-up" requirement in the OVEC ICPA, the "weakest link" is the lowest rating in the sponsor group (currently FES which is in default), thereby constraining the score for this factor (45% weight) at B3 - the floor for this factor in the scorecard grid.

The OVEC sponsor group includes: American Electric Power Company, Inc. (AEP), the largest shareholder with 43.5% in total, through its subsidiaries Ohio Power Company (OPCo: A2, stable) at 19.9%, Appalachian Power Company (Baa1, stable) at 15.7%, and Indiana Michigan Power Company (A3, stable) at 7.9%. Buckeye Power Generating LLC (Baa1, stable) is the next largest shareholder with about 18.0%, followed by Duke Energy Ohio, Inc. (Duke Ohio: Baa1, stable) with 9.0% and FirstEnergy Corp. (FirstEnergy: Baa3, stable) with 8.4% through its wholesale generating subsidiaries FirstEnergy Solutions Corp. (not rated) at 4.9%, Allegheny Energy Supply (not rated) at 3.0% and regulated utility Monongahela Power (Baa2, stable) at 0.5%. PPL Corporation (Baa2, stable) has an 8.1% stake through Louisville Gas and Electric (A3, stable) at 5.6% and Kentucky Utilities (A3, stable) at 2.5%, with the remainder held by Peninsula Generation Cooperative (not rated) at 6.7%, Dayton Power & Light (DPL, Baa2, positive) at 4.9%, and Southern Indiana Gas & Electric (A2, negative) at 1.5%. Peninsula Generation Cooperative (Peninsula) and its parent company, Wolverine Power Supply (Wolverine), are not rated by Moody's. However, we view Peninsula and Wolverine as having investment grade-like characteristics.

Regulatory uncertainty for Ohio based sponsors has diminished

The state of Ohio's transition to a deregulated market for electricity resulted in some uncertainty regarding the permanency and mechanics by which the Ohio based OVEC participants that were once vertically integrated utilities (OPCo, Duke Ohio and DPL) would recover their OVEC obligations. Importantly, the OVEC obligations of these entities remain with the utilities that are parties to the ICPA, even though the sponsors may no longer own any generating assets. The ICPA does not contain a "regulatory out" provision, so the risk of non-recovery lies with the sponsor participants.

In prior rate proceedings, the Public Utilities Commission of Ohio (PUCO) allowed the establishment of placeholder riders, initially set at zero, for the recovery of costs associated with the Ohio utilities' OVEC obligations. In 2016 and 2017, the PUCO authorized OPCo and DPL's utilization of their specific OVEC riders through 2024 and 2023, respectively. The PUCO'S OPCo decision was recently upheld by the Ohio Supreme Court. Duke Ohio's request is still pending. Legislative efforts to make utility cost recovery of OVEC obligations more permanent are also underway.

OVEC's plants are challenged to be cost competitive in current low priced power markets

The low natural gas price environment and greater customer efficiencies/conservation efforts have kept the market price for on-peak energy at the AEP-Dayton hub of PJM during 2018 around $40 per MWh; off-peak prices have generally been around $30 per MWh. This is considerably less than OVEC's all-in cost of power to its participants, which in 2018 is estimated to be about $55 per MWh (including fixed costs and debt service). OVEC has been undertaking cost reduction efforts and estimates its energy only costs are currently around $25 MWh, which frequently allows the plants to run as base load, as they were designed, which reduces operational costs and brings down their overall cost per MWh. For example, OVEC's 2018 all-in cost of $55 MWh is a significant improvement from the $64-65 MWh experienced in 2013 and 2015, and below the $56 MWh experienced in 2014 when production spiked due to severe winter weather. For 2019, OVEC estimates the all-in cost of power to its sponsor companies will be similar to 2018.

Beginning in June 2016, OVEC became responsible for bidding all of the PJM sponsor's available energy into the market, so the entirety of the plants are dispatched on a consistent basis when it is economic. This dispatch practice has improved the plant's use factor (percentage of power scheduled versus power availability) to approximately 84% in 2018 and 2017 compared to approximately 71% in 2016. Increased usage contributes to a lower all-in per MWh cost of power for the sponsors. We note that as a strictly merchant plant, in today's market, the plant would not be able to generate sufficient cash flow cover its fixed costs and service its $1.4 billion of debt.

Elevated carbon transition risk

OVEC has an elevated carbon transition risk profile because its operations are limited to the generation of electricity from two coal-fired electric generating plants: the Kyger Creek Plant (1,086 MW) in Ohio and the Clifty Creek plant (1,304 MW) in Indiana. This places the company at a higher risk than other joint action agencies or regulated and municipal utilities that may have a more diversified generating base or own transmission and distribution assets.

Liquidity analysis

OVEC's liquidity is constrained as its partially drawn bank credit facility, which includes a material adverse change clause for new borrowings, is current and due in less than one year. For the twelve months ended September 30, 2018, OVEC generated approximately $123 million in cash flow from operations (CFO), invested $14 million in capital expenditures and made no dividend payments, resulting in free cash flow (FCF) of approximately $109 million. Over the next 12 months, with limited capital expenditures and no dividend payments, the company should continue to be free cash flow positive. In addition, as of December 31, 2017, OVEC had approximately 97 days of liquidity (including the liquid portion of long term investments) on hand, an increase compared to the 68 days at the end of 2016. These figures fall within the range of 30 – 100 days indicated for a score of "Baa" on this factor in the JAA methodology.

Additional external liquidity is provided by OVEC's $200 million unsecured bank revolving facility which matures in November 2019, but is currently in the process of being extended. Our rating and stable outlook assume this extension is completed in the early part of 2019. At September 30, 2018, OVEC had $85 million borrowed under this line of credit. The facility has a covenant requiring maintenance of a minimum of $11 million of consolidated net worth (defined as stockholders' equity); as of September 30, 2018, we estimated the level to be about $23 million. Draws under the facility require a representation of no material adverse change, a credit negative as it may preclude borrowing under the facility when it is needed most. As such, we have not included revolver availability in our calculation of days liquidity on hand.

As mentioned earlier, management has taken proactive steps to shore up its available liquidity in order to provide near-term coverage for the FES shortfall. Traditionally, joint action agencies will establish a debt service reserve (typically covering one year of debt service) for the benefit of the lenders. At its December 2016 meeting, the OVEC Board authorized the funding of a $44 million debt service reserve over 18 months beginning January 2017, which was equivalent to approximately one third of a year of debt service. OVEC now plans to continue funding this debt reserve at a rate of about $30 million per year (current balance is about $60 million), at least until there is one year of debt service. To date, there have been no draws from the reserve and as of September 30, 2018, OVEC had $60 million of unrestricted cash on hand. In addition to the debt reserve, OVEC's long-term investments also include about $70 million received as part of a prior settlement with the Department of Energy, which could be utilized to cover shortfalls.

Over the next twelve months, we expect OVEC's scheduled debt amortization of approximately $50 million to be recovered through the sponsor's demand charge payments. The company's next non-amortizing debt maturity is in October 2019, when $100 million of revenue bonds mature. In addition, OVEC's upcoming maturities include: 1) $25 million of Ohio Air Quality Development Authority

(OAQDA) variable rate revenue bonds (due in 2026) with letter of credit backing expiring in November 2019, and 2) $50 million of Indiana Finance Authority (IFA) variable rate revenue bonds (due in 2040) with a bank agreement expiring in August 2020. OVEC expects to extend the maturities of these upcoming facilities.

Structural considerations

The strength of the OVEC ICPA is a key factor in determining its credit quality. However, as noted above, the sponsor obligations under the ICPA are several, and there is no requirement for a step-up in payments in the event of a shortfall. A step-up provision, which is common for joint action agencies, would typically require the non-defaulting participants to increase their payments by a maximum percentage (typically 15-25%) in the event a participant default. The ICPA limits assignments of the sponsor obligations to entities that have investment grade ratings from both Moody's and Standard & Poor's. However, there is no ongoing requirement that the existing Sponsors maintain investment grade ratings.

Rating methodology and scorecard factors

Moody's evaluates OVEC's financial performance relative to the US Municipal Joint Action Agencies rating methodology and, as depicted below, based on a lowest possible sponsor score of "B3", the scorecard indicated rating for OVEC is Ba3, two notches below OVEC's Ba1 rating. The Ba1 rating recognizes the small, manageable size of the defaulting sponsor and the overall credit quality of the sponsor group. Our view reflects our expectation that the non-defaulting sponsors will continue to support OVEC through reserves or other means until a longer term solution to the FES shortfall is achieved. Notching factors reflect the current lack of a traditional step-up feature.

Exhibit 1

Factor	Subfactor/Description	Score	Metric
1. Participant Credit Quality and Cost Recovery Framework	a) Participant credit quality. Cost recovery structure and governance	B3	
2. Asset Quality	a) Asset diversity, complexity and history	Baa	
3. Competitiveness	a) Cost competitiveness relative to market	Ba	
4. Financial Strength and Liquidity	a) Adjusted days liquidity on hand (3-year avg) (days)	Baa	69
	b) Debt ratio (3-year avg) (%)	Baa	97%
	c) Fixed obligation charge coverage ratio (3-year avg) (x)	Baa	1.21
Material Asset Event Risk	Does agency have event risk?	No	
Notching Factors		**Notch**	
	1 - Contractual Structure and Legal Environment	-0.5	
	2- Participant Diversity and Concentration	0	
	3 - Construction Risk	0	
	4 - Debt Service Reserve, Debt Structure and Financial Engineering	0	
	5 - Unmitigated Exposure to Wholesale Power Markets	0	
Scorecard Indicated Rating:		**Ba3**	

Source: Moody's Investors Service

Ratings

Exhibit 2

Category	Moody's Rating
OHIO VALLEY ELECTRIC CORP	
Outlook	Stable
Sr Unsec Bank Credit Facility	Ba1
Senior Unsecured	Ba1

Source: Moody's Investors Service

REPORT NUMBER 1154297

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

DUKE ENERGY OHIO EXHIBIT _______

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	))	Case No. 17-34-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Modify Rider PSR.	))	Case No. 17-872-EL-RDR
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Amend Rider PSR.	))	Case No. 17-873-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	))	Case No. 17-874-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)))))	Case No. 17-1263-EL-SSO
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)))	Case No. 17-1264-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Defer Vegetation Management Costs.	))	Case No. 17-1265-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., to Establish Minimum Reliability Performance Standards Pursuant to Chapter 4901:1-10, Ohio Administrative Code.	)))	Case No. 16-1602-EL-ESS

REVISED

PUBLIC VERSION

SUPPLEMENTAL TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

DUKE ENERGY OHIO

July 10, 2018

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Attachment:

Supplemental Attachment JLR-1

PUBLIC Supplemental Attachment JLR-2

PUBLIC Supplemental Attachment JLR-3

PUBLIC Supplemental Attachment JLR-4

PUBLIC Supplemental Attachment JLR-5

PUBLIC Supplemental Attachment JLR-6

I. INTRODUCTION AND SUMMARY

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

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

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS MATTER?

A. Yes.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

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

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

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

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

Energy Ohio is a counterparty to, and sponsoring company[2] of, the Inter-Company Power Agreement (ICPA) pursuant to which its power participation ratio is 9 percent. Hence, Duke Energy Ohio is entitled to 107 MW from Clifty Creek and 88 MW of Kyger Creek for a total of 195 MW. Over the 2012 to 2017 period, average generation from the 195 MW was 0.98 million MWh.

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

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

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

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

Q. HAS YOUR FORECAST PERIOD CHANGED?

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

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

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony contains the following sections:

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

Q. WHAT SPECIFIC FORECASTS ARE YOU PROVIDING?

A. I provide the following forecasts:

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

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

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

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

Q. HOW IS YOUR SUMMARY ORGANIZED?

A. My summary has four main parts:

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

I.1 APPROACH

Q. SUMMARIZE YOUR APPROACH.

A. My approach has three parts. First, I compare the costs of power from Clifty Creek and Kyger Creek with the costs of purchasing the same amount of power from the market under ICF's Base Case conditions. I base my recommendations on the operations of Clifty Creek and Kyger Creek on the cash going-forward economics *i.e.,* excluding sunk costs. I also compare market purchases and the costs of OVEC power including sunk costs. I do not opine on the treatment of sunk costs in terms of recoverability, though I present perspectives on their treatment.

Second, I consider a second scenario using the EIA natural gas price reference case forecast instead of ICF's updated natural gas price base case forecast. This is the only public forecast that uses a theoretically correct methodology. Gas prices are an important uncertainty. This is especially relevant because ICF forecasts that over the next 8 years, demand for natural gas will increase so much that we expect US production will increase from 74 Bcfd to 98 Bcfd – (*i.e.* by 32%). This demand will come from numerous sources including major increases in natural gas exports.

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

Q. SUMMARIZE YOUR ASSUMPTION UPDATES.

A. Key updates include:

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

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

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

I.2 MARKET PRICE FORECASTS

Q. WHAT ARE FIRM ALL-HOURS POWER PRICES?

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

[3] 2025 is a full year for comparison.
[4] The capacity price is averaged across the 8760 hours of the year and added to the all-hours average electrical energy price. The result is a single $/MWh price often referred to as a unit contingent firm price or a bundled price.

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

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

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

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

[5] 2025 is considered full year.

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

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

- **Extreme Conditions** - The winter of 2015/2016 was one of the warmest in US history, and oil prices fell from $108/barrel in early 2014 to less than $30/Barrel in early 2016.
- **Historically Low Prices** - AEP Dayton electrical energy prices were the lowest since 2005, and Henry Hub, Louisiana natural gas prices were the lowest since 1999. Gas prices at Dominion South, another gas price market location north of Pittsburgh, were the lowest ever.
- **Evidence of Non-sustainability** – Between 2014 and 2016, US drilling for oil and gas dropped 75 percent and there were over 100 bankruptcies in small and mid-size oil and gas producers.
- **Price Increases Between 2016 and 2017 and 2018 YTD** – Many spot and forward prices increased over the course of 2016, 2017 through early 2018. The increase in 2017 occurred in spite of 2017 being a warm winter compared to average.
- **Modeling** - Computer model simulations capturing the long-term dynamics of the power and related industries support higher average prices than 2016. This modeling also accounts for general inflation, long-term conditions including regulatory changes, rising demand for gas, etc.

Q. WHAT ARE ELECTRICAL ENERGY PRICES?

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

Q. WHAT IS YOUR FORECAST OF ELECTRICAL ENERGY PRICES?

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

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

A. The key drivers of higher electrical energy prices over time include higher natural gas prices, and higher energy demand as weather returns to average conditions, load growth and retirements, potential new regulations, new unit costs and general inflation (*i.e.,* average economy wide inflation measured using GDP deflator).

Q. WHAT IS YOUR CAPACITY PRICE FORECAST?

A. PJM purchases and OVEC can sell capacity three years forward and the price is expressed as $/MW-day, $/kW-month and $/kW-year. I forecast that [BEGIN CONFIDENTIAL] [redacted] Thus, my updated forecast is [redacted] than my forecast in the Direct Testimony for 2018 to 2025. [END CONFIDENTIAL] This reflects several factors. First, there are changes in historical PJM auction results which I directly incorporate in my forecast. This includes the more than 80% increase in PJM RTO capacity prices the May 2018 auction relative to the May 2017 auction. Second, my post auction forecasts are modestly lower. This is because lower gas prices lead to higher dispatch for marginal capacity price setting units, and I assumed slightly lower physical heat rates for new combined cycles for delivery in 2024/2025.

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

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

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

Q. DOES YOUR CAPACITY PRICE FORECAST INCREASE OVER TIME?

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

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

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

[7] See MIC Balancing Ratio, April 4, 2018, Monitoring Analytics, Joe Bowring, Siva Josyula. See also discussion of this issue in Direct Testimony.
[8] PJM, "*Capacity Market Repricing Proposal*", 2017; PJM, "*Proposed Enhancements to Energy Price Formation*", November 15, 2017.
[9] PJM, *Valuing Fuel Security",*2018; PJM, *"Ott_Fuel Security Member Letter",* April 30, 2018.

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

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

A. Power prices have exhibited very significant annual volatility. I anticipate this significant annual price volatility will continue around my forecast of the expected (*i.e.,* probability weighted) value. I focus on one measure of annual volatility namely the range of annual all hours electrical energy prices for the AEP Dayton Hub. This measure is modestly higher relative to my Direct Testimony. Over the 2012-2017 six-year period, the range was $27.8/MWh to $44.1/MWh with a spread of $16.3/MWh. This spread is 49 percent of the average price, and hence, indicates high volatility. When I factor in capacity prices, the firm price range over the same period was $31.6/MWh to $47.6/MWh and spread was $16/MWh or 44 percent of the average. The high volatility is driven in large part by variation in weather conditions (*e.g.,* weather was warm in the winters of 2012, 2016 and 2017 while the winters were cold in 2014 and 2015 and average[10] in 2013 and 2018), the lack of storage, natural gas price volatility,

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

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

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

A. It is five times higher.

I.3 POWER PLANT FORECASTS

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

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

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

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

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

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

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

[13] Duke Energy Ohio (DEO) owns 9% of the ICPA contract. In this annual average calculation, 2025 is considered as a full year.
[14] In average revenue rate calculation, 2025 is a full year. Revenues on average are higher than all-hours price because dispatch is high but not 100%.
[15] Partial year 2025.
[16] In gross margins average calculation, 2025 is a full year

CONFIDENTIAL] Revenues increase faster than costs and margins increase faster than revenues – *i.e.,* there is operating leverage.

Q. WHAT IS THE FORECAST OF OVEC DEMAND CHARGES?

A. OVEC demand charges are paid pursuant to the ICPA originally entered into in 1953. The demand charges are set in the same manner as cost recovery of a traditional rate base power plant. Duke Energy Ohio provided ICF the forecast of OVEC's projected demand charges.[17] Between 2018 and 2025[18], total demand charges average approximately [BEGIN CONFIDENTIAL] [redacted] As noted, this forecast [redacted] in my Direct Testimony. [END CONFIDENTIAL]

Q. HOW SHOULD SUNK COSTS BE TREATED?

A. Society's economic value[19] is maximized by maximizing the cash going forward net margins and treating previously incurred capital investment as sunk – *i.e.,* by not including sunk costs in the decision regarding the asset's utilization. My economic analysis excluding sunk costs concludes that OVEC should continue to operate its power plants. This is especially true when the hedge value of the contract and the improving price trend is considered.

Duke Energy Ohio is requesting recovery of all costs, including sunk costs, via Rider PSR. I note that this request may be appropriate in spite of the complexities of OVEC's situation, notably the plants are not owned by or rate

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

based by Duke Energy Ohio but are rather subject to a long term power agreement under which Duke Energy Ohio has little control of OVEC. It is my understanding that the specific contract was undertaken long ago (though amended in 2004 and 2011) and well before deregulation of any power markets. The diversity of the players and regulatory frameworks and the regional scope of the situation does not lend itself to easily changing the contract or establishing a policy regarding the future of the plants (*e.g.,* unanimous decision making). This arrangement is consistent with this situation being a legacy of a former era in which the form was secondary to the intent which was to urgently support reliable production of enriched uranium in the early 1950s. While the form of the arrangement is contractual, it may have been the original intent to treat the Department of Defense similar to or better than other firm customers and treat the plants in a manner similar to jointly owned, rate base power plants – *i.e.,* similar to other power plants approved and included in the rate base. Evidence for this is that the payments are determined the same way traditionally regulated costs are determined. This argues for recovery of costs including sunk costs because they were prudently incurred.

Notwithstanding the above, I have not conducted a detailed history of the contract, the plant's regulation, and I defer to the expertise of the PUCO on how to treat the sunk costs with regard to rate recovery for the Company. I also acknowledge that this is a different, complex and unique situation. Finally, it is my understanding that most decisions and changes to the contract require unanimous consent. Accordingly, I also report the results based on the total demand charge including recovery of sunk capital.

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

A. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

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

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

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

[redacted] [END CONFIDENTIAL]

Q. DO THE NET MARGINS INCLUDE HEDGE VALUE?

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

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

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

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

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

[22] Partial year 2025.

[BEGIN CONFIDENTIAL]

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

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

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

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

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

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

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

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

[END CONFIDENTIAL]

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

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

[redacted] [END CONFIDENTIAL]

I.4 CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS?

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

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

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

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

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

Accordingly, I conclude the plants should continue to operate. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

II. RECENT WHOLESALE POWER PRICING TRENDS

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

A. Exhibit 3 below provides wholesale electrical energy market prices for the period from 2009 to 2017.[23] Electrical energy prices are set node-by-node, but PJM reports load weighted zonal averages for demand nodes and hubs and simple averages for supply nodes. Between 2012 and 2017, AEP Dayton Hub all-hours electrical energy prices averaged $33.8/MWh in real 2016 dollars, and $33.1/MWh in nominal dollars. Historically, Clifty Creek and Kyger Creek nodal prices averaged 5.5 percent lower compared to AEP Dayton Hub's all-hours prices. In nominal dollars, the range of AEP Dayton Hub's prices was from $44.1/MWh in 2014 to $27.8/MWh in 2016 or $16.2/MWh – *i.e.,* the lowest prices were in 2016. As noted, 2015/2016 winter weather was among the warmest on record and electrical energy prices and natural gas prices were very low.

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

Exhibit 3
Historical Electrical Energy Prices – All-Hours ($/MWh)

Source	Year	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]
		(2016$/MWh)	(2016$/MWh)	(Nom$/MWh)	(Nom$/MWh)
Historical	2009	36.8	34.9	33.0	31.3
	2010	41.4	39.4	37.6	35.8
	2011	41.8	39.2	38.7	36.4
	2012	33.1	32.0	31.2	30.2
	2013	36.5	33.7	35.0	32.4
	2014	45.1	41.5	44.1	40.5
	2015	31.9	29.9	31.5	29.5
	2016	27.8	26.6	27.8	26.6
	2017	28.6	27.7	29.2	28.2
	2018 YTD	35.1	32.6	36.6	34.0
	2012-2017	**33.8**	**31.9**	**33.1**	**31.2**
	2009-2017	**35.9**	**33.9**	**34.2**	**32.3**

Source: SNL Financial, Ventyx
Notes:
1) The nodal prices for Clifty Creek and Kyger Creek from 2009 to 2015 represents OVEC node. PJM updated its LMP Bus Model on Dec 9, 2015 and added CLFTY and KYGER nodes. 2016 represents average of CLFTY and KYGER nodal prices. These are 8760 hour nodal averages.
2) 2018 YTD represents trades from Jan 1 – May 11, 2018

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

A. As mentioned above, forward PJM capacity prices reflect PJM's auction for three-year forward capacity delivery for June 1 through May 31 of the following year. The auction is called the Base Residual Auction (BRA) and is held in May of each year. Thus, calendar year 2018 capacity prices reflect auction results in May 2014 for the period January 1, 2018 - May 31, 2018, and in May 2015 for June 1, 2018- December 31, 2018. Exhibit 4 shows calendarized 2013 to May 31, 2022 capacity prices from PJM auctions. Over the last 9 years, capacity prices in the RTO sub-region of PJM averaged approximately $36.5/kW-yr in nominal dollars (approximately $100/MW-day). As noted, most of the historic capacity prices do not reflect full implementation of the capacity performance arrangements. Even when PJM procured in the May 2017 auction 100 percent capacity performance product, it used the lowest possible penalty rate from the perspective of the number of hours of emergency; the penalty rate is too low, and hence, bids for the willingness to be exposed to the penalties are too low.

Exhibit 4
PJM Capacity Prices for the RTO Zone (Nom$/kW-yr)

RTO Capacity Prices (Nom$/kW-yr)				
Delivery Period	**Base Residual Auction**	**1st Incremental Auction**	**2nd Incremental Auction**	**3rd Incremental Auction**
2013	8.4	6.8	3.5	1.2
2014	31.0	4.2	6.4	6.0
2015	48.1	10.0	32.8	38.6
2016	33.3	19.3	27.3	25.9
2017	34.6	27.0	10.4	8.5
2018	53.3	18.6	14.7	13.0
2019	46.4	15.1	NA	NA
2020	31.5	NA	NA	NA
2021	41.4	NA	NA	NA
Jan 2022-May 2022	51.1	NA	NA	NA
2013-2021 Average	**36.5**	**14.4**	**15.8**	**15.6**
2018-2021 Average	**43.2**	**16.8**	**14.7**	**13.0**

Source: PJM

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

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

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

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

Source: PJM, Ventyx

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

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

III. UPDATED MARKET MODELING ASSUMPTIONS

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

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

Q. SUMMARIZE YOUR UPDATES.

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

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

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

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

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

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

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

Q. WHAT HAPPENED?

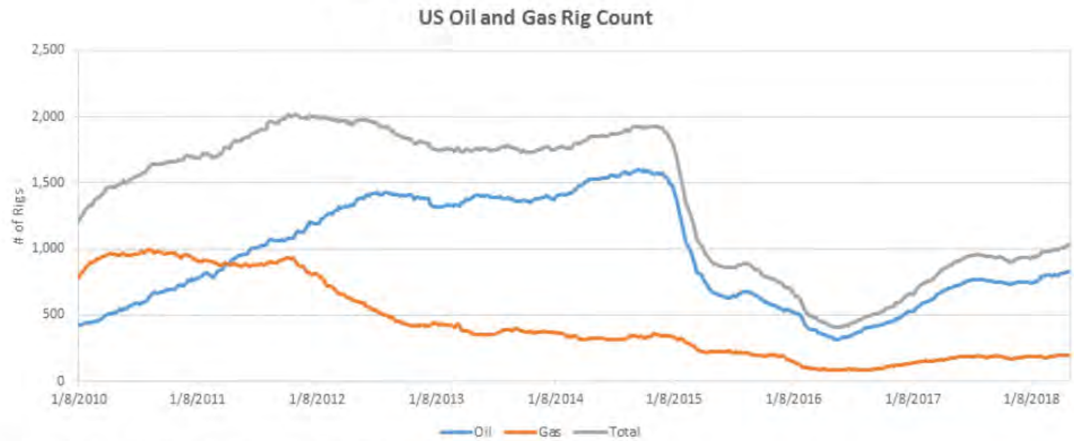
A. All of the above happened. Gas prices recovered 18 to 40 percent depending on location. In 2017, Henry Hub spot prices averaged $2.97/MMBtu, 18 percent above 2016 levels, and Dominion South averaged $2.11/MMBtu, 40 percent above 2016 levels of $1.50/MMBtu (see Exhibit 6). In the year to date 2018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

Exhibit 6
Historical Dominion South Gas Prices

	Henry Hub		Dominion South		Basis WRT HH	
Year	(Nom$/ MMBtu)	(2016$/ MMBtu)	(Nom$/M MBtu)	(2016$/ MMBtu)	(Nom$/ MMBtu)	(2016$/ MMBtu)
2005	8.69	10.53	9.24	11.19	0.55	0.67
2006	6.73	7.91	7.08	8.33	0.35	0.42
2007	6.96	7.97	7.41	8.48	0.44	0.51
2008	8.88	9.97	9.33	10.48	0.45	0.50
2009	3.95	4.40	4.26	4.75	0.31	0.35
2010	4.40	4.84	4.60	5.07	0.21	0.23
2011	4.00	4.32	4.13	4.46	0.13	0.14
2012	2.76	2.92	2.78	2.95	0.02	0.03
2013	3.73	3.89	3.52	3.67	-0.20	-0.21
2014	4.36	4.47	3.30	3.38	-1.06	-1.09
2015	2.64	2.67	1.50	1.52	-1.14	-1.16
2016	2.51	2.51	1.50	1.50	-1.00	-1.00
2017	2.97	2.91	2.11	2.07	-0.86	-0.84
2018 YTD	2.90	2.78	2.50	2.40	-0.40	-0.39
Average 2005-2017	**4.81**	**5.33**	**4.68**	**5.22**	**-0.14**	**-0.11**
Average 2009-2017	**3.48**	**3.66**	**3.08**	**3.26**	**-0.40**	**-0.40**
Average 2012-2017	**3.16**	**3.23**	**2.45**	**2.51**	**-0.71**	**-0.71**

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

Exhibit 7
US Oil and Gas Rig Count



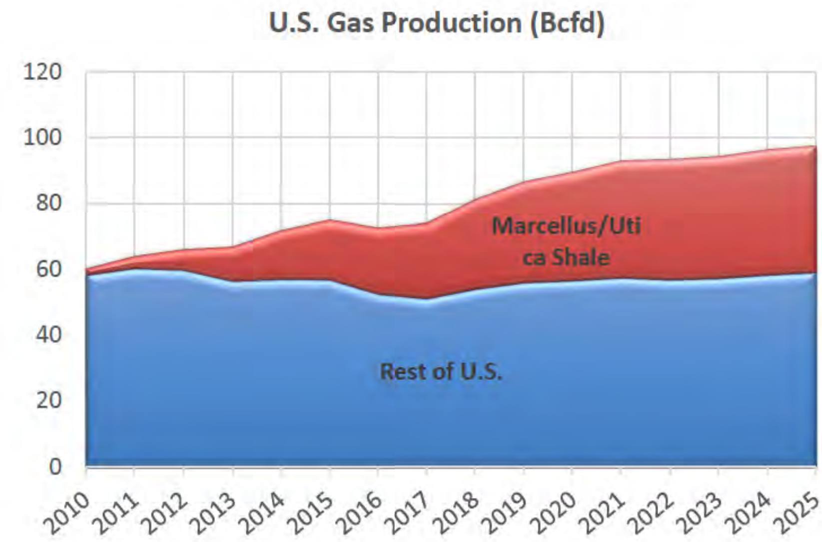
Source: Baker Hughes, from January 8, 2010 to May 4, 2018

Exhibit 8
Marcellus & Utica Gas Production (Bcfd)

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

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

Exhibit 9
Marcellus & Utica Gas Production (Bcfd)



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

Q. WHAT ARE YOUR UPDATED GAS PRICE FORECASTS?

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

Q. WHY IS YOUR CURRENT GAS PRICE FORECAST LOWER?

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

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

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

[redacted]

Notes:
[redacted]
[END CONFIDENTIAL]

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

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

[BEGIN CONFIDENTIAL]

Exhibit 11

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

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

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

Exhibit 12

[BEGIN CONFIDENTIAL] [redacted]

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

Notes:
[redacted]
[END CONFIDENTIAL]

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

A. Yes, there will be very large year-by-year volatility due to weather and economic and industry cycles. Volatility will be especially pronounced in demand areas, also referred to as market areas, where there can be large imbalances between natural gas demand for and availability of natural gas delivery infrastructure. I emphasize my forecasts are of expected or probability weighted values and the yearly volatility around these forecasts are expected.

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

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

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

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

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

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

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

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

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

BEGIN CONFIDENTIAL] Exhibit 14

[redacted]

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

[redacted]

[END CONFIDENTIAL]

IV. UPDATED MODELING ASSUMPTIONS – COAL

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

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

Exhibit 15
Historical NAPP and Illinois Basin Coal Spot Prices.

	NAPP, Upper Ohio River Barge, 12500 Btu/lb, > 6 lb/MMBtu Sulfur				Illinois Basin Barge, 11000 Btu/lb, 5 lb/MMBtu Sulfur			
	Nom$		2016$		Nom$		2016$	
Year	**$/ton**	**$/MMBtu**	**$/ton**	**$/MMBtu**	**$/ton**	**$/MMBtu**	**$/ton**	**$/MMBtu**
2012	49.1	1.96	52.0	2.08	44.5	2.02	47.1	2.14
2013	55.0	2.20	57.3	2.29	42.4	1.93	44.2	2.01
2014	57.5	2.30	58.9	2.36	45.2	2.05	46.3	2.10
2015	50.6	2.02	51.3	2.05	40.0	1.82	40.5	1.84
2016	40.5	1.62	40.5	1.62	35.8	1.63	35.8	1.63
2017	36.3	1.45	35.6	1.42	35.5	1.61	34.8	1.58
2018 YTD	36.6	1.46	35.1	1.40	38.3	1.74	36.7	1.67
Avg (2012-2017)	**46.5**	**1.86**	**47.2**	**1.89**	**40.2**	**1.83**	**40.8**	**1.85**

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

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

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

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

Exhibit 16
Historical Delivered Coal Costs for the OVEC Plants

	Kyger Creek		Clifty Creek	
Year	**2016$**	**Nom$**	**2016$**	**Nom$**
2012	2.28	2.15	2.90	2.73
2013	2.20	2.11	2.75	2.63
2014	2.15	2.09	2.99	2.92
2015	1.94	1.92	2.53	2.49
2016	1.91	1.91	2.23	2.23
2017	1.80	1.84	2.20	2.24
2018 Year to Date	1.76	1.83	1.98	2.07
Average (2012-2017)	**2.05**	**2.00**	**2.60**	**2.54**

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

Q. WHAT IS YOUR FORECAST OF COMMODITY COAL PRICES?

A. Over time (see Exhibit 17), I forecast coal prices will remain relatively flat in real terms on average over time. For example, Northern Appalachia high sulfur 6 lb. SO_2/MMBtu coal prices are projected [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 17

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[END CONFIDENTIAL]

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

A. As shown in Exhibit 18, delivered coal costs at Clifty and Kyger Creek are forecast to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

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

[BEGIN CONFIDENTIAL] Exhibit 18

[redacted]

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

[redacted]

[END CONFIDENTIAL]

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

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

BEGIN CONFIDENTIAL] Exhibit 19

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Exhibit 20

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[redacted]

[END CONFIDENTIAL]

V. UPDATED MODELING ASSUMPTIONS – OTHER

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

A. Yes.

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

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

Q. HOW DID THE UPDATED DEMAND FORECAST CHANGE?

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

Exhibit 21
PJM RTO Zone Demand Forecast

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

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

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

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

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

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

Exhibit 22
PJM Demand Resource Participation in Base Residual Auctions

DR Type	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
ILR	2,107	2,110	2,108	2,110	1,594	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
DR Cleared	128	536	893	939	1,365	7,047	9,282	14,118	14,833	12,408	10,975	11,084	10,348	7,820	11,126
EE Cleared	NA	NA	NA	NA	NA	569	679	822	923	1,117	1,339	1,247	1,515	1,710	2,832
Total DSM	**2,235**	**2,646**	**3,001**	**3,049**	**2,959**	**7,616**	**9,961**	**14,941**	**15,755**	**13,525**	**12,314**	**12,331**	**11,863**	**9,531**	**13,958**
Demand Requirements															
Peak Demand	137,421	139,806	142,177	144,592	142,390	144,857	160,634	164,758	163,168	165,412	164,479	161,418	157,188	153,915	152,647
DR as% of Demand Requirements															
% of Peak	1.6%	1.9%	2.1%	2.1%	2.1%	5.3%	6.2%	9.1%	9.7%	8.2%	7.5%	7.6%	7.5%	6.2%	9.1%
% of Target Reserves	11%	13%	14%	14%	13%	34%	39%	59%	63%	52%	48%	49%	46%	37%	58%
Target Reserve Margin %	15.0%	15.0%	15.0%	15.5%	15.5%	16.2%	15.3%	15.3%	15.4%	15.6%	15.7%	15.7%	16.5%	16.6%	15.8%

Source: PJM-ISO

[BEGIN CONFIDENTIAL]

Exhibit 23

[redacted]

[END CONFIDENTIAL]

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

A. Yes.

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

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

Exhibit 24
PJM - Firm Builds and Retirements (GW)

	Year	Retirements (MW)	Firm Builds - Combined Cycle (MW)
PJM	2010	786	0
	2011	1,325	1,215
	2012	7,027	1,418
	2013	2,859	0
	2014	2,967	2,246
	2015	9,464	1,724
	2016	393	3,710
	2017	2,084	3,325
	2010-2017	**26,903**	**13,638**
	2018	5,377	7,167
	2019	2,631	4,501
	2020	2,062	2,109
	2021	3,058	620
	2018-2021	**13,128**	**14,397**
	2010-2021	**40,031**	**28,035**

Source: PJM-ISO; SNL Financial, Ventyx

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

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

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

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

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

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

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

A. New combined cycle plants are assumed to be available in summer 2021, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] In equilibrium in the long-term, an important driver of scarcity or capacity prices is the annual costs of new entry (*i.e.,* entry by a new natural gas-fired combined cycle). [BEGIN CONFIDENTIAL] [redacted]

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

[redacted] [END CONFIDENTIAL] New power plant costs vary by region as a function of variation in underlying labor and material costs, ambient conditions, local environmental regulations (to the extent applicable), etc. Financing assumptions are also important because the annual costs of capital investment are a function of both financing costs and capital costs. ICF has assessed the required rate of return for new entrants using the Capital Asset Pricing Model ("CAPM"). [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

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

Q. WHAT DO YOU ASSUME ABOUT RENEWABLES?

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

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

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

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

VI. ELECTRICITY PRICE PROJECTIONS – ALL-HOURS ELECTRICAL ENERGY

Q. HAVE ELECTRICAL ENERGY PRICES RECOVERED FROM 2016 LEVELS?

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

Exhibit 25
Historical Electrical Energy Prices – All-Hours ($/MWh)

Source	Year	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]	AEP-Dayton Hub	Clifty and Kyger Creek Nodal Average[1]
		(2016$/MWh)	(2016$/MWh)	(Nom$/MWh)	(Nom$/MWh)
Historical	2009	36.8	34.9	33.0	31.3
	2010	41.4	39.4	37.6	35.8
	2011	41.8	39.2	38.7	36.4
	2012	33.1	32.0	31.2	30.2
	2013	36.5	33.7	35.0	32.4
	2014	45.1	41.5	44.1	40.5
	2015	31.9	29.9	31.5	29.5
	2016	27.8	26.6	27.8	26.6
	2017	28.6	27.7	29.2	28.2
	2018 YTD	35.1	32.6	36.6	34.0
	2012-2017	**33.8**	**31.9**	**33.1**	**31.2**
	2009-2017	**35.9**	**33.9**	**34.2**	**32.3**

Source: SNL Financial, Ventyx
Notes:
[1] The nodal prices for Clifty and Kyger Creek from 2009 to 2015 represents OVEC node and represents the 8760 hour nodal average. PJM updated its LMP Bus Model on Dec 9, 2015 and added CLFTY and KYGER nodes. 2016 represents average of CLFTY and KYGER nodal prices
[2] 2018 YTD represents trades from Jan 1 – May 11, 2018

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

A. Yes, for 2018 through 2025.

Q. WHAT ELECTRICAL ENERGY PRICES DID YOU FORECAST?

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

- AEP Dayton hub all-hour, real and nominal dollars;
- Clifty Creek and Kyger Creek all-hour nodal, real and nominal dollars; and
- Realized Clifty Creek and Kyger Creek nodal prices, real and nominal dollars where realized refers to the prices in the hours in which the power plants dispatch.

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

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

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

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

Source: ICF
Note: 2025 is a full year

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

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

Source: ICF
Note: 2025 is a full year
[END CONFIDENTIAL]

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

A. Nodal prices for the two power plants are modestly [BEGIN CONFIDENTIAL] [redacted] the AEP Dayton hub prices. Between 2018 and 2025, I forecast that Clifty Creek and Kyger Creek all-hour nodal prices will be [redacted]

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

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

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

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

A. In all future years in the forecast, electrical energy prices are [BEGIN CONFIDENTIAL] [redacted] 2016 on a nominal dollar basis. Specifically, in 2016, the average all-hour electrical energy price was $27.8/MWh. Thus, the 2018 forecast price of [redacted] than the 2016 price. Between the years 2018 to 2025, nominal average of [redacted] than the 2016 price. [END CONFIDENTIAL]

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

A. First, it is not surprising that prices are [redacted]. 2016 prices were lower than in any year since 2005[28] and 2016 prices were 20 percent lower than the 2009 to 2016 average price of $34.9/MWh. 2016 included the warmest US winter on record, and 2016 annual Henry Hub gas prices were lower than any year since 1999.[29] Second, and more specifically, my forecast energy price for 2018 is [redacted] than the 2016 price because: (1) the Henry Hub gas price is [redacted] (2) the Dominion South gas prices is [redacted] and (3) energy demand is assumed to reflect normal weather, [redacted] [END CONFIDENTIAL]

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

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

[28] SNL Financial's recording of AEP Dayton Hub price stops at 2005.
[29] The 2016 Henry Hub prices $2.51/MMBtu and the first lowest year before 2016 was 1999 at $2.27/MMBtu.

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

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

	Source	AEP-Dayton Hub- All-hour Energy Price	Dominion South Gas Price	Market Implied Heat Rate- All-hour
Year	**Energy/Gas**	**(Nom$/MWh)**	**Nom$/MMBtu**	**Btu/kWh**
2012	Historical/Historical	31.2	2.95	10,604
2013	Historical/Historical	35.0	3.69	9,491
2014	Historical/Historical	44.1	3.47	12,704
2015	Historical/Historical	31.5	1.67	18,884
2016	Historical/Historical	27.8	1.68	16,592
2017	Historical/Historical	29.2	2.28	12,798
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average (2012-2017)		**33.1**	**2.62**	**13,512**
[redacted]		[redacted]	[redacted]	[redacted]

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

[END CONFIDENTIAL]

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

A. The 2018 to 2025 nominal average of [BEGIN CONFIDENTIAL] [redacted] higher than the 2016 price. The 2025 nominal average of [redacted] than the 2016 price of $27.8/MWh. In all forecast years, prices are [redacted] [END CONFIDENTIAL]

Q. WHAT ARE THE FORWARD ELECTRICAL ENERGY PRICE TRENDS?

A. Wholesale forward prices are available from the Bloomberg L.P. ("Bloomberg")[30] through December 31, 2021 for energy. In 2018[31], the forward price of $32.4/MWh is higher than the ICF forecast of [BEGIN CONFIDENTIAL] [redacted] due in large part to a non-weather normal January. By 2021, the forwards for all-hours AEP-Dayton Hub prices slightly decrease to $29.9/MWh and is 2 percent [redacted] (see Exhibit 29). [END CONFIDENTIAL] However, the liquidity of the forward price is very limited past the first year of reporting, and provide only very limited information about market opinion. It can also be hard to trade in illiquid markets where any sizable position (*i.e.*, buy or sell) actually changes the prices, and reported prices are often based on bids and asks rather than actual market transactions. Also, forwards are very volatile and follow spot prices. Thus, while we used forward gas and capacity prices we did not use forward power prices.

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

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

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

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

VII. POWER PLANT DISPATCH AND REALIZED ELECTRICAL ENERGY PRICES

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

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

Exhibit 30
Historical Capacity Factors for the OVEC Plants (%)

Year	Kyger Creek	Clifty Creek
2011	74%	74%
2012	54%	55%
2013	59%	53%
2014	63%	58%
2015	42%	50%
2016	61%	50%
2017	73%	60%
Average (2011-2017)	**61%**	**57%**

Source: SNL Financial, Ventyx

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

A. Between 2018 and 2025, I forecast the average plant utilization rates will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The increase reflects increasing natural gas and electrical energy prices, the impact of retirements, growing demand, and the lack of new coal power plant construction.

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

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

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

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

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

[32] 2025 is a full year for comparison

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

A. Kyger Creek and Clifty Creek will dispatch more in hours with higher prices, and hence, the average realized price of the plants should be higher than the all-hours nodal average – *i.e.,* the price realized in the hours the plant is operated is higher than the all-hour market price average. Between 2018 to 2025, I forecast the average realized energy prices will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Realized prices are only slightly higher due to the strong dispatch of both plants.

[BEGIN CONFIDENTIAL] Exhibit 32
ICF Forecast of All-Hours Hub, Nodal and Realized Nodal Energy Prices ($/MWh)

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

Source: ICF
Note: [redacted]

[END CONFIDENTIAL]

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

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

A. PJM capacity prices for January 1, 2018 to May 31, 2022 reflect actual auction results (blending auction capability year results into calendar years results) for the PJM RTO sub-regions. The capacity price across this large PJM sub-region reflects the auction cleared price for all those LDAs that did not separate in price during the auction process. These capacity prices come directly from PJM's BRA results.

Q. HOW ARE CAPACITY PRICES PROJECTED FOR JUNE 1, 2022 TO MAY 31, 2025?

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

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

A. In the near term, capacity prices are set at levels in the BRA capacity auction and in the longer run the price is set at levels needed to support new builds.

Q. WHAT ARE YOUR CAPACITY PRICE FORECASTS?

A. ICF's capacity price forecasts are shown in Attachment III and Exhibit 33. I forecast that the average capacity price [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Regarding the already determined capacity prices, the RTO capacity price for delivery years 2018[33] to May 2022 averages $40.7/kW-yr in real 2016 dollars, and $43.9/kW-yr in nominal dollars.

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

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

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[33] Calendarization of 2017/2018, 2018/2019, 2019/2020, 2020/2021.
[34] This includes full year pricing for 2025. Also we note that the January 1, 2022 to May 31, 2022 capacity prices in this analysis are set equal PJM capacity auction prices.

[BEGIN CONFIDENTIAL] Exhibit 33
PJM Capacity Prices – 2018 to 2025

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

[redacted]

Exhibit 34

[redacted]

Note: 2025 is a full year.

[END CONFIDENTIAL]

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

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

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

A. Yes. There are four reasons. First, as discussed in my Direct Testimony, the capacity performance rules are supposed to set the penalty rate such that plants are indifferent between bidding net CONE times the balancing ratio (typically 80 to 90 percent) or being-energy only. Put another way, there is supposed to be an opportunity cost to providing capacity. However, PJM has not properly set the penalty rate – it is too low because the expected hours of penalty are too high. When this happens the penalty is too low because the penalty is the ratio of the net CONE times balancing ratio divided by the hours. A recent Market Monitoring report discusses what the hours of expected penalty should be as FERC concluded there is not an adequate basis for the estimate used (the current estimate for the RTO of 30 hours is based on a single year), and PJM itself has released historical data[35] showing the hour estimate is too high. Once this is fixed, prices will be more stable and move closer to net CONE.

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

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

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

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

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

Q. DO THESE REGULATORY CHANGES QUANTITATIVELY AFFECT YOUR FORECAST?

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

Q. WHAT ARE FIRM ALL-HOUR PRICES?

A. Firm unit-contingent all-hour prices combine energy and capacity into a single $/MWh price_by amortizing capacity payment over all the hours. As shown below in Exhibit 35, the average firm price between 2018 and 2025 is [BEGIN CONFIDENTIAL] [redacted]. In the near term, the average forecast all-hours firm price between 2018 and 2025 equals [redacted] than the recent historical average of $36.5/MWh over the 2012 to 2017 time period. [END CONFIDENTIAL]

[36] "*Capacity Market Repricing Proposal*", PJM 2017.
[37] Scoping document draft, "Valuing Fuel Security", PJM, 2018. See also Letter from Andrew Ott to PJM Members, April 30, 2018.
[38] "*Proposed Enhancements to Energy Price Formation*", PJM, November 15, 2017.

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

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

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

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

Source: Ventyx, PJM-ISO, ICF
Note: 2025 is a full year.
[END CONFIDENTIAL]

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

A. Power prices have exhibited very significant annual volatility (*i.e.,* variance). I anticipate this significant annual price volatility will continue around the expected value. I focus on one measure of annual volatility namely the range of annual all-hour electrical energy prices for the AEP Dayton Hub. Over the 2012-2017 six-year period, the range was $27.8/MWh to $44.1/MWh or $16.3/MWh (see Exhibit 36). This range is 49 percent of the average price, and hence, indicates high volatility. When I factor in capacity prices, the firm price range over the same period was $31.6/MWh to $47.6/MWh and range was $16/MWh or 44 percent of the average. This range is slightly higher in my updated forecast. The high volatility is driven in large part by variation in weather conditions (weather was warm in the winters of 2012 and 2016 while the winters were cold in 2014 and 2015), the lack of storage, natural gas price volatility, variation in generation supply costs, industry cycles and changes in FERC regulations. Greater reliance on spot natural gas will increase spot power price volatility, especially in situations where natural gas production and delivery infrastructure falls behind increased natural gas consumption.

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

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

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

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

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

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

IX. PROJECTIONS OF REVENUES AND GROSS MARGINS

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

A. Over the 2018 to 2025 period, in nominal dollars, I forecast the average revenues for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] The average revenue rate including all revenue streams will be [redacted] The growth rate in revenues between 2018 and 2025 is [redacted]. [END CONFIDENTIAL]

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

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

Kyger Creek

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

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

Clifty Creek

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

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

[END CONFIDENTIAL]

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

A. My updated forecast of total revenues on an annual average basis is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

A. Gross margin is revenues less fuel and other short run variable costs including emission allowance costs. Over the 2018 to 2025, in nominal dollars, I forecast the average annual gross margins for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] Gross margins average [redacted] On average, the plants receive gross margins of [redacted] [END CONFIDENTIAL]

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

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

X. PROJECTIONS OF DEMAND CHARGES AND NET MARGINS

Q. DID YOU UPDATE OVEC DEMAND CHARGES?

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

Q. WHAT IS THE FORECAST OF OVEC DEMAND CHARGES?

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

- **Total Costs** - Between 2018 and 2025, the total demand charge averages approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on a levelized or annuity basis. This can be further broken down into two parts.

[40] Partial year 2025.

- **Recovery of Past Capital Cost/"Sunk" Costs** – Between 2018 and 2025, recovery of and on previously invested capital comprises [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]
- **Cash Going Forward Cost** - Between 2018 and 2025, cash going forward costs *i.e.*, fixed annual O&M and property taxes, incremental maintenance capital expenditures, G&A averages [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

Q. HOW SHOULD SUNK COSTS BE TREATED?

A. Society's economic value[41] is maximized by maximizing the cash going forward net margins and treating previously incurred capital investment as sunk – *i.e.,* by not including sunk costs. When I conduct this economic analysis, I conclude that the OVEC plants should continue to operate.

[41] Assuming efficient pricing.

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

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

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

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

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

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

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

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

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

[BEGIN CONFIDENTIAL] **Exhibit 40**

[redacted]

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

Exhibit 41

[redacted]

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

[redacted]

[END CONFIDENTIAL]

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

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

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

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

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

A. Including all of the demand charges[45] and using the Base Case results, the OVEC plants' net margins are [BEGIN CONFIDENTIAL] [redacted] on a net present value basis. [redacted] The net margin decreases [redacted] [END CONFIDENTIAL]

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

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

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

A. Annual wholesale market price volatility is [BEGIN CONFIDENTIAL] [redacted] than volatility in the costs of Clifty Creek and Kyger Creek. The range of average delivered coal cost over the 2012 to 2017 was $2/MMBtu to $2.5/MMBtu or $0.5/MMBtu. This was [redacted] of the average. Total costs ranged from [redacted]. This [redacted] of the average. This compares favorably to the [redacted] for the firm power price – *i.e.,* the volatility of the market is approximately [redacted] [END CONFIDENTIAL]

XI. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS?

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

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

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

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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

Judah L. Rose ICF

Senior Vice President, Managing Director

Education

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

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

Awards and Recognition

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

Experience Overview

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

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

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

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

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

Accomplishment Highlights

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

Selected Press Interviews

Television "The Most With Allison Stewart," MSNBC, "Blackouts in NY and St. Louis & ongoing Energy Challenges in the Nation," July 25, 2006
CNBC Wake-Up Call, August 15, 2003
Wall Street Journal Report, July 25, 1999
Back to Business, CNBC, September 7, 1999

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

Magazines: Business Week
Power Economics
Costco Connection

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

Wires: Associated Press
Bridge News
Dow Jones Newswires

Testimony

133. Expert Declaration, in support of (1) The motion for preliminary and permanent injunction against FERC (2) The motion for entry of an order authorizing to reject certain energy contracts (3) The motion for entry of an order authorizing to reject a certain multi-party intercompany power purchase agreement with the Ohio Valley Electric Corporation. On behalf of FES, March 31, 2018.
132. Direct Testimony, Case No. 17-872-EL-RDR, On behalf of Duke Energy Ohio, March 31, 2017131. Affidavit, In Answer to Complaint of Next Era and PSEG Companies, FERC Docket No. EL16-93-000, Testimony on New Gas Pipelines, and Wholesale Gas and Power Market Design, July 28, 2016. On behalf of Eversource.
130. Rebuttal Testimony, Support for an Electric Security Plan Filing, on behalf of Ohio Edison Company, The Cleveland Electric illuminating Company, The Toledo Edison Company, Case No. 14-1297-EL-SSO, October 20, 2015.
129. Demand Resource Pricing Testimony on behalf of P3, Docket ER15-852-000, February, 13, 2016
128. Damages Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, January 5, 2015.

127. Responsive Testimony of Judah L. Rose on Behalf of Oklahoma Energy Results, LLC December 16, 2014, CAUSE NO. PUD 201400229
126. Rebuttal Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, November 26, 2014.
125. Statement of Opinions on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, October 30, 2014.
124. Direct Testimony, CO_2 price forecasts provided to IPL for use in their compliance analysis, as well as, support for the probabilities assigned to the Coal Combustion Residuals ("CCR"), 316 (b) and Effluent Limitation Guidelines ("ELG") regulations for use in IPL analysis in support of their Compliance Project, Indianapolis Power & Light Company, IURC Cause No. 44540, October 14, 2014.
123. Direct Testimony, Support for an Electric Security Plan Filing, Ohio Edison Company (FirstEnergy), August 4, 2014.
122. Rebuttal Testimony, Valuation of Mad River Power Plant, FirstEnergy, February 27, 2014.
121. Expert Report, Computation of Future Damages, Breach of Wolf Run Coal Sales Agreement, prepared for Meyer, Unkovic, and Scott, LLP, filed February 12, 2014.
120. Supplemental Direct Testimony of Judah Rose on behalf of National Grid and Northeast Utilities, Petition of New England Power Company d/b/a/ National Grid for Approval to Construct and Operate a New 345 kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69J, August 8, 2013.
119. Rebuttal Testimony of Judah Rose on Behalf of Monongahela Power Company, The Potomac Edison Company, Petition for Approval of a Generation Resource Transaction and Related Relief, Case No. 12-1571 – E – PC, May 17, 2013.
118. Direct Testimony of Judah Rose on behalf of New England Power Company d/b/a National Grid before the Commonwealth Of Massachusetts Energy Facilities Siting Board and Department Of Public Utilities, Petition of New England Power Company d/b/a National Grid for Approval to Construct and Operate a New 345kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69, Docket EFSB 12-1/D.P.U. 12-46/47, November 21, 2012.
117. Direct Testimony for the Narragansett Electric Company d/b/a National Grid (Interstate Reliability Project), Before the State of Rhode Island Public Utilities Commission, Energy Facility Siting Board ("Siting Board") Notice of Designation to Public Utilities Commission ("PUC") to Render an Advisory Opinion on need and cost-justification for Narragansett Electric d/b/a National Grid's proposal to construct and alter major energy facilities in RI, the "Interstate Reliability Project", RIPUC Docket No. 4360, November 21, 2012
116. Sur-Surrebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, September 21, 2012.
115. Rebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, July 30, 2012.

114. Direct Testimony, The Connecticut Light & Power Company, Application for a Certificate of Environmental Compatibility and Public Need for the Connecticut Portion of the Interstate Reliability Project that traverses the municipalities of Lebanon, Columbia, Coventry, Mansfield, Chaplin, Hampton, Brooklyn, Pomfret, Killingly, Putnam, Thompson, and Windham, which consists of (a) new overhead 345-kV electric transmission lines and associated facilities extending between CL&P's Card Street Substation in the Town of Lebanon, Lake Road Switching Station in the Town of Killingly, and the Connecticut/Rhode Island border in the Town of Thompson; and (b) related additions at CL&P's existing Card Street Substation, Lake Road Switching Station, and Killingly Substation, Docket No. 424, July 17, 2012.
113. Direct Testimony, Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, February 9, 2012.
112. Rebuttal Testimony, Otter Tail Power Company, Before the Office of administrative Hearings, for the Minnesota Public Utilities Commission, In The Matter of Otter Tail Power Company's Petition for an Advance Determination of Prudence for its Big Stone Air Quality Control System Project, September 7, 2011.
111. Rebuttal Testimony, on behalf of Arizona Public Service, In the Matter of the Application of Arizona Public Service Company for Authorization for the Purchase of Generating Assets from Southern California Edison, and for an Accounting Order, Docket No. E-01345A-10-0474, June 22, 2011.
110. Direct Testimony, Duke Energy Ohio, Inc., Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service, Case No. 11-XXXX-EL-SSO. Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. Case No. 11-XXXX-EL-ATA. Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. Case No. 11-XXXX-EL-UNC, June 20, 2011.
109. Direct Testimony, Manitoba Hydro Power Sales Contracting Strategy, U.S. Power Markets, Manitoba Hydro Drought Risks, Modeling, Forecasting and Planning, Selected Risk and Financial Issues, Governance, Trading and Risk Related Comments Before the Public Utilities Board of Manitoba, February 22, 2011.
108. Sur-rebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2010-0356, January 12, 2011.
107. Rebuttal Report Concerning Coal Price Forecast for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed December 6, 2010.
106. Direct Testimony of Judah Rose on behalf of Duke Energy Ohio In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service, Case No. 10-2586-EL-SSO, filed November 15, 2010.
105. Updated Forecast, Coal Price Report for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed October 18, 2010.

104. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 29, 2010.
103. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 16, 2010.
102. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line Oklahoma LLC to conduct Business as an Electric Utility in the State of Oklahoma, Cause No.PUD 201000075, July 16, 2010.
101. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line LLC for a Certificate of Public Convenience and Necessity to Operate as an Electric Transmission Public Utility in the State of Arkansas, Docket No. 10-041-U, June 4, 2010.
100. Supplemental Testimony on Behalf of Entergy Arkansas, Inc., In the Matter of Entergy Arkansas, Inc., Request for a Declaratory Order Approving the Addition of the Environmental Controls Project at the White Bluff Steam Electric Station Near Redfield, Arkansas, Docket No. 09-024-U, July 6, 2009.
99. Rebuttal Testimony on Behalf of TransEnergie, Canada, Province of Quebec, District of Montreal, No.: R-3669-2008-Phase 2, FERC Order 890 and Transmission Planning, July 3, 2009.
98. Sur-rebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, before the Missouri Public Service Commission, In the Matter of the Application of KCP&L GMO, Inc. d/b/a KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2009-0090, April 9, 2009.
97. Hawaii Structural Ironworkers Pension Trust Fund v. Calpine Corporation, Case No. 1-04-CV-021465, Assessment of Calpine's April 2002 Earnings Projections, March 25, 2009.
96. Coal Price Report for Harrison Coal Plant, Allegheny Energy Supply Company, LLS and Monongahela Power Company versus Wolf Run Mining Company, Anker Coal Group, etc., Civil Action. No. GD-06-30514, In the Court of Common Pleas, Allegheny County, Pennsylvania, February 6, 2009.
95. Supplemental Direct Testimony of Judah Rose, on behalf of Southwestern Electric Power Company, In the Matter of the Application of Southwestern Electric Power Company for Authority to Construct a Natural-Gas Fired Combined Cycle Intermediate Generating Facility in the State of Louisiana, Docket No. 06-120-U, December 9, 2008.
94. Rebuttal Testimony of Judah Rose on behalf of Kelson Transmission Company, LLC re: Application of Kelson Transmission Company, LLC For A Certificate of Convenience and Necessity For the Amended Proposed Canal To Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, And Orange Counties, SOAH Docket No. 473-08-3341, PUCT Docket No. 34611, October 27, 2008.
93. Testimony of Judah Rose, on behalf of Redbud Energy, LP, in Support of Joint Stipulation and Settlement Agreement, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of the Purchase of the Redbud Generating Facility and Authorizing a Recovery Rider, Cause No. PUD 200800086, September 3, 2008.

92. Direct Testimony of Judah L. Rose on behalf of Duke Energy Carolinas, In the Matter of Advance Notice by Duke Energy Carolinas, LLC, of its Intent to Grant Native Load Priority to the City of Orangeburg, South Carolina, and Petition of Duke Energy Carolinas, LLC and City of Orangeburg, South Carolina for Declaratory Ruling With Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority, Docket No. E-7, SUB 858, August 15, 2008.
91. Affidavit filed on behalf of Public Service of New Mexico pertaining to the Fuel Costs of Southwest Public Service for Cost-of-Service and Market-Based Customers, August 11, 2008.
90. Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio, Inc., Before the Public Utilities Commission of Ohio, In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan, July 31, 2008.
89. Rebuttal Testimony, Judah L. Rose on Behalf of Duke Energy Carolinas, in re: Application of Duke Energy Carolinas, LLC for Approval of Save-A-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket No. E-7, Sub 831, July 21, 2008.
88. Updated Analysis of SWEPCO Capacity Expansion Options as Requested by Public Utility Commission of Texas, on behalf of SWEPCO, June 27, 2008.
87. Direct Testimony of Judah L. Rose on Behalf of Nevada Power/Sierra Pacific Electric Power Company, Docket No. 1, Public Utilities Commission of Nevada, Application of Nevada Power/Sierra Pacific for Certificate of Convenience and Necessity Authorization for a Gas-Fired Power Plant in Nevada, May 16, 2008.
86. Rebuttal Testimony of Judah L. Rose on Behalf of the Advanced Power, Commonwealth of Massachusetts, Before the Energy Facilities Siting Board, Petition of Brockton Power Company, LLC, EFSB 07-7, D.P.U. 07-58 & 07-59, May 16, 2008.
85. Supplemental Rebuttal Testimony on Commissioner's Issues of Judah L. Rose for Southwestern Electric Power Company, on behalf of Southwestern Electric Power Company, PUC Docket No. 33891, Public Utilities Commission of Texas, May 2008.
84. Supplemental Direct Testimony on Commissioners' Issues of Judah Rose for Southwestern Electric Power Company, for the Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas, SOAH Docket No. 473-07-1929, PUC Docket No. 33891, Public Utility Commission of Texas, April 22, 2008.
83. Rebuttal Testimony of Judah Rose, In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008.
82. Rebuttal Report of Judah Rose, Ohio Power Company and AEP Power Marketing Inc. vs. Tractebel Energy Marketing, Inc. and Tractebel S.A. Case No. 03 CIV 6770, 03 CIV 6731 (S.D.N.Y.), January 28, 2008.
81. Proposed New Gas-Fired Plant, on behalf of AEP SWEPCO, 2007.
80. Rebuttal Report, Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 21, 2007.
79. Expert Report. Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 19, 2007.

78. Application of Duke Energy Carolina, LLC for Approval of Energy Efficiency Plan Including an Energy Efficiency Rider and Portfolio of Energy, Docket No. 2007-358-E, Public Service Commission of South Carolina, December 10, 2007.
77. Independent Transmission Cause No. PUD200700298, Application of ITC, Public Service of Oklahoma, December 7, 2007.
76. Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code š8-1-2.5-1, et. Seq. for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance With Ind. Code šš8-1-2.5-1 et seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the PowerShare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Cause Earnings and Expense Tests, Indiana Utility Regulatory Commission, Cause No. 43374, October 19, 2007.
75. Rebuttal Testimony, Docket No. U-30192, Application of Entergy Louisiana, LLC For Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery, October 4, 2007.
74. Direct Testimony of Judah Rose on Behalf of Tucson Electric Power Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, July 2, 2007.
73. Supplemental Testimony on behalf of Southwestern Electric Power Company before the Arkansas Public Service Commission, In the Matter of Application of Southwestern Electric Power Company for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation, and Maintenance of a Coal-Fired Base Load Generating Facility in the Hempstead County, Arkansas, dated June 15, 2007, Docket No. 06-154-U.
72. Rebuttal Testimony, Causes No. PUD 200500516, 200600030, and 20070001 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, June 2007.
71. Rebuttal Testimony on behalf of Duke Energy Indiana, IGCC Coal Plant CPCN, Cause No. 43114 before the Indiana Utility Regulatory Commission, May 31, 2007.
70. Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 2007.
69. Rebuttal Testimony on behalf of Florida Power & Light Company In Re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant, Docket No. 070098-EL, March 30, 2007.
68. Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 2007.
67. Direct Testimony for Southwestern Electric Power Company, Before the Louisiana Public Service Commission, Docket No. U-29702, in re: Application of Southwestern

Electric Power Company for the Certification of Contracts for the Purchase of Capacity for 2007, 2008, and 2009 and to Purchase, Operate, Own, and Install Peaking, Intermediate and Base Load Coal-Fired Generating Facilities in Accordance with the Commission's General Order Dated September 20, 1983. Consolidated with Docket No. U-28766 Sub Docket B in re: Application of Southwestern Electric Power Company for Certification of Contracts for the Purchase of Capacity in Accordance with the Commission's 'General Order of September 20, 1983, February 2007.

66. Second Supplemental Testimony on Behalf of Duke Energy Ohio Before the Public Utility Commission of Ohio, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA, February 28, 2007.
65. Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, February 2007.
64. Supplemental Testimony on behalf of Duke Energy Carolinas before the North Carolina Utilities Commission in the Matter of Application of Duke Energy Carolinas, LLC for Approval for an Electric Generation Certificate of Public Convenience and Necessity to Construct Two 800 MW State of Art Coal Units for Cliffside Project, Docket No. E7, SUB790, December 2006.
63. Expert Report, Chapter 11, Case No. 01-16034 (AJG) and Adv. Proc. No. 04-2933 (AJG), November 6, 2006.
62. IGCC Coal Plant, Testimony on behalf of Duke Energy Indiana, Cause No. 43114, October 2006.
61. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106 OAL Docket No. PUC-1874-05, Supplemental Testimony March 20, 2006.
60. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Surrebuttal Testimony December 27, 2005.
59. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, November 14, 2005.
58. Brazilian Power Purchase Agreement, confidential international arbitration, October 2005.
57. Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.
56. Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.
55. Cost of Service and Fuel Clause Issues, Testimony on behalf of Public Service of New Mexico, FERC Docket No. EL05-151-000, September 15, 2005.
54. Cost of Service and Peak Demand, FERC, Responsive Testimony on behalf of Public Service of New Mexico, August 23, 2005, Docket No. EL05-19.
53. Prudence of Acquisition of Power Plant, Testimony on behalf of Redbud, September 12, 2005, No. PUD 200500151.
52. Proposed Fuel Cost Adjustment Clause, FERC, Docket Nos. EL05-19-002 and ER05-168-001 (Consolidated), August 22, 2005.
51. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU, FERC, Docket EC05-43-000, May 27, 2005.

50. New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.
49. Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.
48. New Air Emission Regulations and Investment in Coal Power Plants, supplemental testimony on behalf of PSI, January 21, 2005, Causes 42622 and 42718.
47. Damages Due to Rejection of Tolling Agreement Including Discounting, January 10, 2005, CONFIDENTIAL.
46. Discount rates that should be used in estimating the damages to GTN of Mirant's bankruptcy and subsequent abrogation of the gas transportation agreements Mirant had entered into with GTN, December 15, 2004. CONFIDENTIAL
45. New Air Emission Regulations and Investment in Coal Power Plants, testimony on behalf of PSI, November 2004, Causes 42622 and 42718.
44. Rebuttal Testimony of Judah Rose on behalf of PSI, "Certificate of Purchase as of yet Undetermined Generation Facility" Cause No. 42469, August 23, 2004.
43. Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, Mohave Coal Plant Economics, June 4, 2004.
42. Supplemental Testimony "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, May 20, 2004.
41. "Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Coal-Fired Generating Station," May 14, 2004.
40. "Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.
39. "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.
38. "Valuation of Selected MIRMA Coal Plants, Acceptance and Rejection of Leases and Potential Prejudice to Leasors" Federal Bankruptcy Court, Dallas, TX, March 24, 2004 CONFIDENTIAL.
37. "Certificate of Purchase as of yet Undetermined Generation Facility", Cause No. 42469 for PSI, March 23, 2004.
36. "Ohio Edison's Sammis Power Plant BACT Remedy Case", In the United States District Court of Ohio, Southern Division, March 8, 2004.
35. "Valuation of Power Contract," January 2004, confidential arbitration.
34. "In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, Coal-Fired and Gas-Fired Market Values, July 21, 2003.
33. "In the Supreme Court of British Columbia", July 8, 2003. CONFIDENTIAL
32. "The Future of the Mohave Coal-Fired Power Plant – Rebuttal Testimony", California P.U.C., May 20, 2003.

31. "Affidavit in Support of the Debtors' Motion", NRG Bankruptcy, Revenues of a Fleet of Plants, May 14, 2003. CONFIDENTIAL
30. "IPP Power Purchase Agreement," confidential arbitration, April 2003.
29. "The Future of the Mohave Coal-Fired Power Plant", California P.U.C., March 2003.
28. "Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL
27. "Power Purchase Agreement Valuation", Confidential Arbitration, October 2002.
26. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02."
25. "Cause No. 42200 - in support of PSI's petition for authority to recover through retail rates on a timely basis. Filed on 7/30/02."
24. "Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."
23. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002."
22. "Analysis of an IGCC Coal Power Plant", Minnesota state senate committees, January 22, 2002.
21. "Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002
20. "Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001
19. "The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000
18. "Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL
17. "Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL
16. Application of FirstEnergy Corporation for approval of an electric Transition Plan and for authorization to recover transition revenues, Stranded Cost and Market Value of a Fleet of Coal, Nuclear, and Other Plants, Before PUCO, Case No. 99-1212-EL-ETP, October 4, 1999 and April 2000.
15. "Issues Related to Acquisition of an Oil/Gas Steam Power plant in New York", September 1999 Affidavit to Hennepin County District Court, Minnesota
14. "Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages", Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.
13. "Power Prices." Testimony in confidential contract arbitration, July 1998.
12. "Horizontal Market Power in Generation." Testimony to New Jersey Board of Public Utilities, May 22, 1998.
11. "Basic Generation Services and Determining Market Prices." Testimony to the New Jersey Board of Public Utilities, May 12, 1998.
10. "Generation Reliability." Testimony to New Jersey Board of Public Utilities, May 4, 1998.
9. "Future Rate Paths and Financial Feasibility of Project Financing." Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.
8. "Stranded Costs of PSE&G." Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.

7. "Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code." Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.
6. "Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy." Testimony to Louisiana Public Service Commission, December 1996.
5. "Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.
4. "Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.
3. "Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.
2. "Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public Service Commission, May 1993.
1. "The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (Der), Hearings on Fuel Diversity and Environmental Protection, December 1992.

Selected Speaking Engagements

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

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

81. Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.
80. Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.
79. Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.
78. Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.
77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.
76. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.
75. Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York, NY, October 8, 2003.
74. Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.
73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.
72. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.
71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, "Spark Spread Outlook", July 17, 2003.
70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and Economy", June 24, 2003.
69. Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel Management Seminar, Frederick, MD, June 10, 2003.
68. Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for Recovery," March 31, 2003.
67. Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City, VA, March 25, 2003.
66. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.
65. Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY, February 24, 2003.
64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).
63. Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.
62. Rose, J.L., "Assessing U.S. Regional and the Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.

61. Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.
60. Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.
59. Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.
58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.
57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.
56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.
55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.
54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001
53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001
52. Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001
51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001
50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001
49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001
48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.
47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000.
46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000
45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.
44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.
42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.
41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.
40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.
39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.
38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.
37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.
36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.
35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.
34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.
33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.
32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.
31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management Conference, Washington, D.C., March 25, 1999.
30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development Conference, Chicago, Illinois, March 23, 1999.
29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting Conference, Atlanta, Georgia, February 25, 1999
28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.
27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.
25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.
24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.
23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.
22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.
21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.
20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.
19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.
18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.
17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.
16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.
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14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.
13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.
12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.
11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.
10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.
8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.
7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.
6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.
5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.
4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.
3. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.
2. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,
1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

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

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

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Rose, J.L., D. Kathan, and J. Spencer "Electricity Deregulation in the New England States," *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, "Financial Engineering in the Power Sector," *The Electricity Journal,* Jan/Feb 1997.

Rose, J.L, S. Muthiah, and M. Fusco, "Is Competition Lacking in Generation? (And Why it Should Not Matter)," *Public Utilities Fortnightly,* January 1, 1997.

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Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information," *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.

Employment History

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

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Attachment VI OVEC Plant Parameters [BEGIN CONFIDENTIAL]

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

Source: 1) ICF, 2) SNL Financial, 3) PJM-ISO, 4)www.OVEC.com, 5) OVEC "20yearbillable.xls" spreadsheet, 6)Duke Energy Ohio

[END CONFIDENTIAL]

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 3
CASE NO. U-21427

DATA REQUEST NO. 3-14-SC

Request

Indicate whether any environmental capital costs are included in the projected demand charges for the OVEC plants during 2024 or any other year in the 5-year planning period.

Response

Costs associated with CCR and ELG capital projects are included in the forecasted demand charges for 2024-2028. However, forecasted OVEC demand charges are based on information prepared and subsequently provided by OVEC to the Company. I&M did not have any role in OVEC's creation of the forecasts.

Preparer

Stegall

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 3
CASE NO. U-21427

DATA REQUEST NO. 3-15-SC

<u>Request</u>

Produce OVEC's projected environmental capital spending at the OVEC plants during 2024-2028.

<u>Response</u>

I&M objects to this request on the grounds that it calls for an analysis and/or calculation that I&M has not performed and objects to performing. In support of this objection, the Company has not calculated, and therefore does not have, the requested information.

<u>Preparer</u>
Stegall

<u>As to Objection</u>
Counsel

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL,
CITIZENS UTILITY BOARD, AND SIERRA CLUB
DATA REQUEST SET NO. AG-CUB-SC 1
CASE NO. U-21596

DATA REQUEST NO. AG-CUB-SC 1-21

Request

Refer to Chilcote direct, pages 7-9: a.: Produce the forecasts that I&M relied on to enter into the coal supply agreements that produced the current inventory levels you describe and that will continue to increase those inventories. b.: Describe how I&M's amendment of its contracts with suppliers – as discussed on pages 8-9 impacted PSCR costs. c.: Describe in detail the steps I&M has taken to maximize storage capability at Rockport and CCT including any impact on PSCR costs.

Response

a. Please see AG 1-21 Confidential Attachment 1 for the requested information. In further response, the Company notes that since the amendment of the supply agreement in 2024 and the filling of the inventories at both Rockport and Cook Coal terminal in 2024, the Company's forecast does not show a need to further reduce the inventory as inventory will gradually return to normal levels with the consumption of coal throughout the upcoming years.

b. The buy-out payment made to the supplier was recorded to account 1510004 in 2024 and has no impact on the 2025 projected PSCR rate.

c. The Company has set maximum inventory levels for each facility which are determined by the permitted coal pile storage area and the safety requirements for coal storage. During 2024, the Company stored coal up to the maximum level for the facility at Rockport and Cook Coal Terminal. The maximum limit for both facilities is a total of approximately 2.7 million tons, however, for a limited time and if the need arises, the facilities can store up to 3.8 million tons with the approval of management at each facility. By the end of 2024, the inventory stored a Rockport and CCT was approximately 3.2 million tons. The facilities were storing coal in areas considered for emergency use only and were seeking to lower the inventory levels to the set maximum of 2.7 million tons. The costs associated with the increased volume of coal stored at both facilities is similar to that of the Company's traditional cost of storing coal which is approximately $2.00/ton as discussed in the direct testimony of Company Witness Chilcote at 8. The use of this additional emergency storage has no impact on the 2025 PSCR projected rate.

Preparer:
Kimberly K. Chilcote

PROOF OF SERVICE - U-21596

The undersigned certifies that a copy of the ***Public Direct Testimony of Devi Glick by the Attorney General, Sierra Club, and CUB*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 4th day of March 2025.

Michael E. Moody Digitally signed by Michael E. Moody Date: 2025.03.04 16:52:16 -05'00'

Michael E. Moody

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