March 4, 2024

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21427

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Exhibits of Devi Glick on behalf of Sierra Club and Citizens Utility Board of Michigan (SC-1 through SC-13, SC-15, SC-17 through SC-32); and
- Proof of Service.

Please note that there is both a Public and Confidential Version of this Direct Testimony. The Confidential Version is only being served on those with an NDC on file in this case. Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Christopher Bzdok
DN: cn=Christopher Bzdok, o=Troposphere Legal, email=chris@tropospherelegal.com, c=US
Date: 2024.03.04 16:34:28 -05'00'

Christopher M. Bzdok
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CC: Parties to Case No. U-21427

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 (2024).	Case No. U-21427

DIRECT TESTIMONY OF DEVI GLICK

ON BEHALF OF

SIERRA CLUB AND
CITIZENS UTILITY BOARD OF MICHIGAN

PUBLIC VERSION

March 4, 2024

DIRECT TESTIMONY OF DEVI GLICK OBO SC & CUB
CASE NO. U-21427

TABLE OF CONTENTS

LIST OF EXHIBITS ii

LIST OF TABLES iv

LIST OF FIGURES iv

I. INTRODUCTION AND PURPOSE OF TESTIMONY 1

II. FINDINGS AND RECOMMENDATIONS 4

III. I&M CUSTOMERS ARE PAYING UNREASONABLE PRICES TO OVEC FOR POWER UNDER THE ICPA……… 6

A. I&M purchases power from OVEC under the ICPA 6

B. I&M projects to pass on to ratepayers $101.5 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. 9

C. A reasonable price to pay for power under the ICPA should be measured based on the market-equivalent value of the services provided. 21

D. I&M's IRP analysis on OVEC is an outlier among nearly half a dozen forward-going analysis which all confirm my findings that OVEC is projected to be uneconomic to operate going forward. 28

E. OVEC has invested over $[[[redacted]]]million in environmental upgrades at the OVEC plants, some of which will be recovered from Michigan ratepayers during the PSCR period, all while I&M is projecting plummeting capacity factors for the OVEC plants 34

F. 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. 40

IV. I&M IS IMPRUDENTLY OPERATING THE ROCKPORT UNITS, LEADING TO EXCESS COSTS TO ITS RATEPAYERS 41

A. I&M is responsible for 100 percent of the cost to operate Rockport Unit 1 beginning in 2023 41

B. 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 43

LIST OF EXHIBITS

SC-1:	Resume of Devi Glick
SC-2C:	I&M Response to Sierra Club Request 1-09 (Confidential)
SC-3:	I&M Response to Sierra Club Request 1-15 with Atts 1-2
SC-4C:	I&M Response to Sierra Club Request 1-16 with Atts 1-3 (Confidential)
SC-5C:	I&M Response to Sierra Club Request 1-17 with Att 1 (Confidential)
SC-6:	I&M Response to Sierra Club Request 1-18 with Att 1 (Confidential)
SC-7:	I&M Response to Sierra Club Request 1-20 with Revised Suppl Att 1
SC-8:	I&M Response to Sierra Club Request 3-02 with Att 1
SC-9:	I&M Response to Sierra Club Request 3-04 with Att 2
SC-10:	I&M Response to Sierra Club Request 3-05 with Att 1
SC-11C:	I&M Response to Sierra Club Request 3-06 with Att 1 (Confidential)
SC-12C:	I&M Response to Sierra Club Request 3-12 with Att 1 (Confidential)
SC-13C:	I&M Response to Sierra Club Request 3-16 with Att 1 (Confidential)
SC-14:	*Reserved*
SC-15:	Ohio Valley Electric Cooperative Annual Report, 2022
SC-16:	*Reserved*
SC-17:	Amended and Restated Inter-Company Power Agreement, Sept. 10, 2010
SC-18:	U-15800 2023 MPSC Staff Transfer Price Schedule
SC-19:	Brattle PJM CONE 2026/2027 Report, Apr. 2022

SC-20: PJM, 2024/2025 RPM Base Residual Auction Results

SC-21: PJM, 2023/2024 RPM Base Residual Auction Results

SC-22: Gross Avoidable Costs for Existing Generation, Jan. 9, 2023

SC-23: PJM, Interconnection Process Reform Task Force Update, May 11, 2021

SC-24: Case No. U-21051, OVEC Stakeholder Meeting Slide

SC-25: Motion for Entry of an Order Authorizing FirstEnergy Solutions Corp. and FirstEnergy Generation LLC to Reject a Certain Multi-Party Intercompany Power Purchase Agreements with the Ohio Valley Electric Cooperative as of the Petition Date (Doc. 44, filed Apr. 1, 2018), In re FirstEnergy Solutions Corp., No. 18-50757 (AMK) (Bankr. ND. Ohio)

SC-26: Expert Declaration of Judah Rose (Doc. 46, filed Apr. 1, 2018), In re FirstEnergy Solutions Corp., No. 18-50757 (AMK) (Bankr. ND. Ohio)

SC-27: Moody's Investors Service, Dec. 2018, Credit Opinion: Ohio Valley Electric Cooperative

SC-28: Revised Public Version of Supplemental Testimony of Mr. Judah L. Rose on behalf of Duke Energy Ohio, Inc., July 10, 2018, Ohio PCU No. 17-0872-EL-RDR

SC-29: US EPA, State Budgets for the Good Neighbor Plan

SC-30: Excerpt from Clifty Creek NPDES Permit No. IN00041759 Application, Nov. 29, 2022, pp. 98-99

SC-31: Michael Ball, Viewpoint: NOx could rise on new regulations, Argus Media, Dec. 29, 2022

SC-32: EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet

LIST OF TABLES

Table 1. Confidential I&M historical and projected power costs for OVEC 14

Table 2. OVEC power costs billed to I&M and market value (2017–2023) ($Nominal) 18

Table 3. OVEC cost benchmarks ($2024) 23

Table 4. Summary of prior OVEC and ICPA studies 28

Table 5. Total power cost for Rockport 1 in current and prior PSCR dockets 44

LIST OF FIGURES

Figure 1. Historical and projected capacity factors for OVEC...11

Figure 2. CONFIDENTIAL Net forecasted OVEC revenues, I&M portion 15

Figure 3. Historical and projected natural gas prices (U.S. EIA AEO projections from 2022 and 2023) 19

Figure 4. CONFIDENTIAL Projected long-term debt costs to be included in the demand charges billed under the ICPA 33

Figure 5. CONFIDENTIAL Rockport 1 projected net revenues, 2024–2028...............................45

I. 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 before state utility regulators in more than a dozen 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 11 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit SC-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club and the Citizens Utility Board of Michigan.

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

A Yes, I submitted testimony in Case No. U-20224, Indiana Michigan Power Company's ("I&M" or "Company") 2019 power supply and cost recovery ("PSCR") reconciliation docket; Case No. U-20804, I&M's 2021 PSCR Plan docket; Case No. U-20530, I&M's 2020 PSCR reconciliation docket, Case No. U-21052, I&M's 2022 PSCR Plan docket, Case No. U-20805, I&M's 2021 PSCR reconciliation docket, Case No. U-21261, I&M's 2023 PSCR Plan docket, Case No U-20528, DTE's 2020 PSCR reconciliation docket. I am also filing testimony in Case No. U-21051, DTE's 2022 PSCR reconciliation docket.

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 2024 and for the five-year forecast period (2024–2028). 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 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 (2024) and the five-year forecast period (2024–2028) 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 1 in its creation of its 2024 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.

II. <u>FINDINGS AND RECOMMENDATIONS</u>

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 the I&M's own data and projections. I&M estimates it will incur excess costs of $101.5 million in energy market revenue and capacity value over the five-year PSCR forecast period (2024–2028) (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 (2025–2028) are roughly quadruple what the Company projected previously and range between $97.54 and $414.63/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 [[redacted]] 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 around $[[redacted]] million in Coal Combustion Residuals ("CCR") and Effluent Limitation Guidelines ("ELG") compliance upgrades at the Clifty Creek and Kyger plants has resulted in significant 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. Within this time I&M is also projecting a decrease in OVEC's capacity factor from around 50 percent to around 6 percent.

6. I&M's latest fuel cost plan and five-year forecast indicate I&M intends to operate Rockport Unit 1 at below a 17 percent capacity factor during the PSCR Plan period and less than 8 percent in 2028, all while passing on to ratepayers costs that exceed market revenues by $112.5 million per year on average.

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 2024–2028. 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.

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

A. 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 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

[1] Ex SC-15, OVEC Annual Report, 2022; Ex SC-17, 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)

[5] Ex SC-15, OVEC 2022 Annual Report, pp. 1 and 43.

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 AEP's Executive Vice President of Generation, Dr. Paul Chodak, is the President of both OVEC and IKEC. Prior to holding his current position at AEP, Dr. Chodak was President and Chief Operating Officer of I&M.

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

A I&M's share of the ICPA with OVEC is 7.85 percent.[7] 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 MW.[8] The cost of the ICPA is passed through to I&M ratepayers as a direct cost. During the 2024 PSCR year, I&M projects it will be billed over $50 million[9] for 544,744 MWh.[10] This works out to a cost of $91.87/MWh.[11] This is an increase from the $80.87/MWh cost in 2023.[12]

[6] *Ibid.*

[7] *Ibid.*

[8] Ex SC-3, I&M Response to Sierra Club 1-15, SC 1-15 Attachment 2.

[9] I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, Line 11; Exhibit IM-17 (SAS-4).

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

[11] I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, Line 11; Exhibit IM-17 (SAS-4).

[12] Ex SC-7, I&M Response to Sierra Club 1-20, SC 1-20 Supplemental Attachment 1 (revised).

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]

B. I&M projects to pass on to ratepayers $101.5 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

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

[14] Ex SC-17, 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.

purchase agreements (PPA) from generation assets owned by other entities or affiliates, and (3) PJM market power purchases.

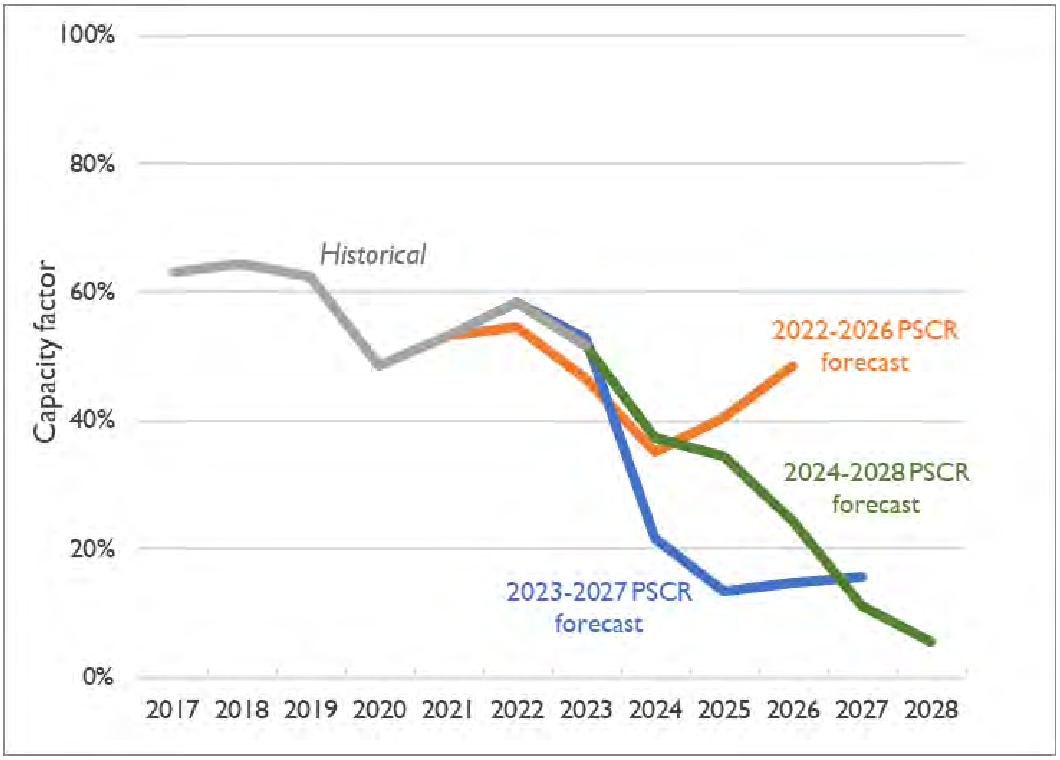
For units owned or leased by I&M, the Company forecasts the fuel costs associated with running the units in the PSCR docket. I&M recovers these costs directly through the PSCR factor. All other operational costs are the subject of separate proceedings (rate cases and riders). For power purchased under 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 to drop from 37 percent in 2024 down to 24 percent by 2026 and 6 percent by 2028.[16] As shown in Figure 1 below, this forecast of decreased utilization deviates from OVEC's historical practices and from I&M's PSCR plan projections from as recently as 2022.

[16] Calculated based on Exhibit IM-17 (SAS-4); Ex SC-3, I&M Response to Sierra Club Request 1-15, SC 1-15 Attachment 1.

Figure 1. Historical and projected capacity factors for OVEC



Source: Exhibit IM-17 (HAB-9); Case No. 21052, Exhibit IM-9 (HAB-9); Case No. 21261, Exhibit IM-9 (HAB-9).

Q How do I&M's utilization assumptions in this docket align with the utilization assumptions I&M relied on in its most recent OVEC analysis submitted in Integrated Resource Plan Case No. U-21189?

A The OVEC economic analysis that I&M prepared in Case No. U-21189 (which I will discuss in more detail below) likely does not utilize the same forecast of declining utilization that the Company used in this current PSCR Plan docket. This is concerning because the Company is claiming that its integrated resource plan ("IRP") analysis supports its position that continuing to rely on OVEC is in the best interest of its ratepayers,[17] but this analysis is clearly outdated and inaccurate.

[17] Direct Testimony of Company Witness Stegall, p. 5.

I&M's utilization assumptions[18] for OVEC are unlikely to be aligned across its current PSCR plan analysis and its IRP analysis because, as shown in Figure 1 above, its capacity factor assumptions in this PSCR docket deviate significantly from both OVEC's historical performance and I&M's forecasts in the 2022 PSCR plan docket. I&M created the IRP analysis around the same time as the 2022 PSCR docket, therefore it is likely that the Company's assumptions across those two analyses were at least somewhat aligned. A higher capacity factor for OVEC means more energy market revenues to make the plant look more economic than it actually is.

Lower utilization is good in reducing fuel costs incurred from uneconomic plant operations, but bad if there are high fixed costs that ratepayers are paying in exchange for very few MWh of electricity.

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

A No. According to OVEC's most recent annual report from 2022, the combined equivalent availability of the OVEC plants dropped from 70.8 percent in 2021 to 66.3 percent in 2022. The combined equivalent forced outage rate (EFOR) for the plants was 11 percent in 2022, up from 6.6 percent in 2021.[19] For the plan period (2024–2028) OVEC projects that its equivalent availability for the plants will be around [[[redacted]]] percent and that its EFOR will be [[[redacted]]] percent.[20]

[18] Exhibit IM-17 (SAS-4); Ex SC-3, I&M Response to Sierra Club Request 1-15, SC 1-15 Attachment 1.

[19] Ex SC-15, OVEC 2022 Annual Report, p. 2.

[20] Ex SC-6, I&M Response to Sierra Club Request 1-18, SC 1-18 Confidential Attachment 1.

Q Has OVEC had any challenge with its coal supply?

A [[[redacted]]]

Additionally, I&M witness Scott admits that the financial health of the coal industry is currently weak, stating that most coal suppliers cannot meet I&M's credit requirements, but suppliers continue to meet their contractual obligations nonetheless.[22]

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 $91.87/MWh during the 2024 PSCR plan year, and between $97.54 and $414.63/MWh over the remainder of the PSCR Plan period (2025–2028).[23] These forecasted costs for the PSCR period are alarmingly high. They are far above what I&M has paid for OVEC power in the past, and they reflect a steady increase in the cost per MWh to operate the OVEC plants. The forecasted PSCR costs are also much higher than OVEC's own projections of the ICPA billable costs be over the remaining life of the contract (between now and 2040).[24] With power costs this high, I&M will be paying substantially above market price for power from OVEC (likely

[21] Ex SC-5, I&M Response to Sierra Club Request 1-17, SC 1-17 Confidential Attachment 1.

[22] Direct Testimony of Darryl Scott, p. 6.

[23] Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachment 1.

[24] Ex SC-12, I&M Response to Sierra Club Request 3-12, SC 3-12 Confidential Attachment 1.

at least double the cost of market power – and likely even more) over the entire PSCR plan period.

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

	Actual costs ($/MWh)	OVEC Projected ICPA Billable cost summary 2022–2040 ($/MWh)	I&M Projected OVEC Costs 2024–2028 PSCR Plan ($/MWh)
2017	$53.72		
2018	$53.43		
2019	$55.59		
2020	$66.07		
2021	$65.74		
2022	$69.18		
2023	$80.87	[[[redacted]]]	
2024		[[[redacted]]]	$91.87
2025		[[[redacted]]]	$97.54
2026		[[[redacted]]]	$123.55
2027		[[[redacted]]]	$225.34
2028		[[[redacted]]]	$414.63

Source: Ex SC-7, I&M Response to Sierra Club Request 1-20, SC 1-20 Supplemental Attachment 1 (revised); Exhibit IM-9 (HAB-9); I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17, Line 11; Ex SC-12, I&M Response to Sierra Club Request 3-12, SC 3-12 Confidential Attachment 1.

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 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 (2024–2028) the OVEC units are likely to cost I&M ratepayers $101.5 million in present-value terms more than the market value of services, or an average of $23.0 million per year above market (as shown in Figure 2 below). This works out to a total of $15 million over the PSCR period or $3.4 million per year for the Michigan jurisdictional share of I&M share of OVEC.

Figure 2. CONFIDENTIAL Net forecasted OVEC revenues, I&M portion

[redacted]

Source: Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachments 1-3.; Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachments 2; Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachment 3.

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 2024–2028 of OVEC's estimated power sales (MWh),[25] and billable costs under the ICPA, broken down by energy charges and demand charges.[26] The Company also provided projected monthly energy market prices.[27]

[25] Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachment 1.

[26] *Id*.

[27] Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Attachment 3.

Using I&M's GWh projection and the energy price projections, I calculated the value of the energy provided by OVEC. The Company also provided capacity values[28] and ICAP values[29] for 2024–2028, 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 2023 according to public data obtained from the U.S. Environmental Protection Agency's (EPA) Clean Air Markets Division.[30]

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 $481.1/MW-Day ($2024) over the PSCR forecast period (2024–2028). 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 combined-cycle unit at $464/MW-Day and above the cost for a new combustion-turbine unit at $372/MW-Day in $2022, assuming

[28] Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachment 2.

[29] Ex SC-3, I&M Response to Sierra Club Request 1-15, SC 1-15 Attachment 1.

[30] U.S. Environmental Protection Agency, "Air Markets Program Data," accessed 18 January 2024. Accessible at: https://campd.epa.gov/data/custom-data-download.

an online date of June 1, 2026/2027 (the values cited in the report are $502/MW-Day and $403/MW-day for combined-cycle and combustion-turbine units respectively in $2026).[31] 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 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, rebound to lower levels.

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 Stegall claims in his testimony that OVEC has been profitable on an energy-only basis in every year except 2020;[32] 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, 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. And as discussed above, the cost of OVEC is projected to jump significantly going forward during the PSCR Plan period.

[31] Ex SC-19 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; PJM Cost of New Entry, Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date. Brattle, April 19, 2019. Accessible at https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

[32] *See* Direct Testimony of Jason Stegall, pp. 8-9, Table JMS-1.

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)

Source: I&M Response to Sierra Club Request 3-04, SC 3-04 Confidential Attachment 1; Ex SC-7, I&M Response to Sierra Club Request 1-20, SC 1-20 Supplemental Attachment 1 (revised); Ex SC-3, I&M Response to Sierra Club Request 1-15, SC 1-15 Attachment 2; I&M Response to Sierra Club Request 3-04, SC 3-04 Attachment 2.

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 have fallen substantially in 2023; and even though price volatility is likely to remain, it is not predicted to be sustained at near the level it was in 2022.

Q Why is it not reasonable to use OVEC's financial performance in 2022 as indicative of an upturn in OVEC's overall economic performance going forward?

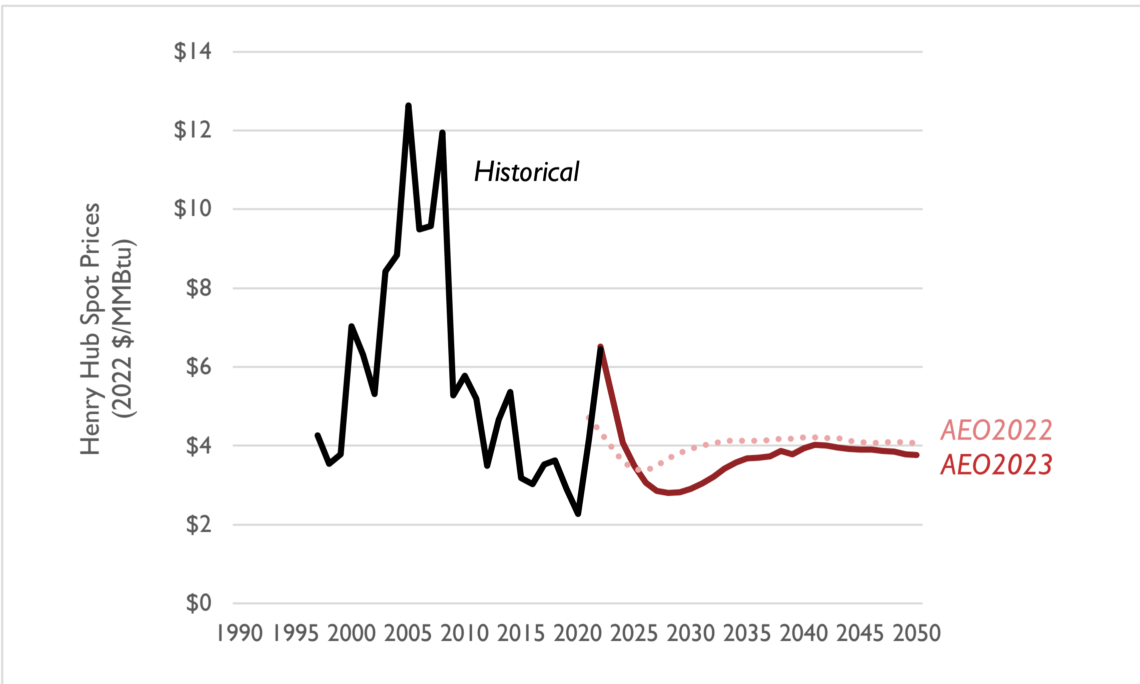
A First, as already discussed, I&M's own projections for the PSCR period show a dramatic increase in OVEC costs on a $/MWh basis.

Additionally, in 2022, the war in Ukraine drove up global energy prices.[33] That combined with overall inflationary pressures drove up natural gas and market prices across the United

[33] See, for example, *Energy commodity prices in 2022 showed effects of Russia's full-scale invasion of Ukraine*, U.S. Energy Information Administration. January 3, 2023. Available at https://www.eia.gov/todayinenergy/detail.php?id=55059.

States. Natural gas prices have already fallen substantially in 2024, and they reached record-low levels in February.[34] Further, natural gas prices are projected to remain low going forward as shown in Figure 3 below. The most recent gas price forecasts released by the U.S. Energy Information Administration (US EIA) in March 2023 as part of its Annual Energy Outlook (AEO) predict project gas prices will fall even lower in coming years than the Administration had previously projected (see the difference between AEO 2022 and AEO 2023 forecasts in Figure 3 below).

Figure 3. Historical and projected natural gas prices (U.S. EIA AEO projections from 2022 and 2023)



Source: U.S. EIA AEO 2022; U.S. EIA AEO 2023; U.S. EIA Henry Hub Natural Gas Prices, available at *https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm*.

[34] *Today in Energy: Henry Hub daily natural gas spot price fell to record lows in February*. U.S. Energy Information Administration. February 28, 2024. Available at https://www.eia.gov/todayinenergy/detail.php?id=61484.

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 2017–2023, which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[35] The Company provided energy and ancillary revenue by month.[36] The Company provided the ICAP values associated with its share of OVEC by month.[37] I estimated a capacity value based on I&M's share of OVEC capacity value received in the PJM Base Residual Auction ("BRA").[38]

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.

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[35] Ex SC-7, I&M Response to Sierra Club Request 1-20, SC 1-20 Supplemental Attachment 1 (revised).

[36] I&M Response to Sierra Club Request 3-04, SC 3-04 Attachment 2; Ex SC-9, I&M Response to Sierra Club Request 3-04, SC 3-04 Attachment 1.

[37] Ex SC-3, I&M Response to Sierra Club Request 1-15, SC 1-15 Attachment 2.

[38] Ex SC-21, PJM 2023/2024 RPM Base Residual Auction Results. Available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx.

C. A reasonable price to pay for power under the ICPA should be measured based on the market-equivalent value of the services provided

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 An AEPSC "benchmark study," conducted on behalf of OVEC, found that the ICPA was expected to have a cost of $7.51 billion on a present-value basis between the years 2011 and 2040.[39] This means I&M's share of the contract was expected to cost $589.4 million on a present-value basis in 2011.[40]

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, consider I&M's actual system needs, or 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.

[39] AEPSC Benchmark Study, April 27, 2011.

[40] *Ibid.*

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 Stegall cites the 2011 benchmark study (as well as the initial 2004 benchmark study) as evidence that the ICPA was more favorable than alternatives.[41]

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 unit 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 long-term PPAs; (2) the cost of replacement capacity resources as represented by the

[41] Direct Testimony of Jason Stegall, pp. 7–8.

CONE; (3) the gross avoidable cost of existing generation for typical PJM plants of various types; 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 ($2024)

	Capacity cost ($/MWh)	Energy cost ($/MWh)	Total cost* ($/MWh)	Excess costs based on 2024 benchmark ($ million)
OVEC 2023 PSCR cost[1] ($2023)	$43.15	$35.97	$79.11	NA
OVEC 2024 PSCR cost[2]	$57.06	$34.81	$91.87	NA
Cost of similar services				
In-year Transfer Price[3]			$62.11	$16.21
Value of CONE & PJM BRA (base residual auction, using ICPA energy costs)				
CONE – combined-cycle plant[4]	$32.68	$27.93	$60.62	$17.03
Gross avoidable cost for existing generation - coal[5]	$8.41	$55.46	$63.87	$15.25
Gross avoidable cost for existing generation - CC[5]	$8.15	$31.29	$39.44	$28.56
Gross avoidable cost for existing generation - CT[5]	$45.19	$39.61	$84.80	$3.85
PJM BRA[6]	$3.54	$34.36	$37.90	$29.40

Sources: [1] Ex SC-7 I&M Response to Sierra Club 1-20, SC 1-20 Supplemental Attachment 1; [2] I&M Response to Staff 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, line 11; Exhibit IM-9 (HAB-9); [3] Ex SC-18 U-15800 2023 MPSC Staff Transfer Price Schedule ; [4] Ex SC-19 Brattle PJM CONE 2026/2027 Report, April 2023; [5] Ex SC-22Gross Avoidable Costs for Existing Generation, Prepared for PJM by Brattle Group. January 9, 2023; [6] Ex SC-21 2023/2024 BRA Results.

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 combined-cycle unit is $502/MW-Day (in $2026) for the capacity cost.[42] To find the capacity cost in $/MWh, I the 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 based on the average annual capacity factor of 64 percent,[43] and the representative plant size from the CONE report.[44] 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 based on Brattle's heat rate and plant size assumptions,[45] 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 July 2023 fundamental forecast.[46] 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

[42] Ex SC-19, Brattle PJM CONE 2026/2027 Study, April 2022, https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

[43] 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.

[44] Ex SC-19, Brattle PJM CONE 2026/2027 Study, April 2022, https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx. Table 4.

[45] Ibid, Table 4.

[46] I&M Response to Sierra Club Request 1-5, SC 1-5 Attachment 1.

a new combined-cycle unit. This incredibly conversative measure of CONE for a new combined-cycle 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 most recent 2024/2025 BRA because there remains surplus capacity available in the PJM region. This auction produced a capacity price of only $28.92/MW-Day for years 2024–2025, which is the lowest it has been in the past 10 auctions.[47] And capacity prices are expected to continue to remain at modest levels far below CONE for at least the next few years, based on downward pressure from two main sources: (1) increased supply from the massive quantities of solar and wind (and even gas resources) in the PJM interconnection queue, many of which are coming online in the coming years;[48] (2) relaxation of the Minimum Offer Price Rule ("MOPR"), which more fully allows for capacity credit of new renewables to show up in the PJM capacity auctions—as dramatically evidenced in the first two Reliability Pricing Model ("RPM") auction results since the relaxation of the MOPR. The most recent PJM RPM auction cleared more solar PV resources than any previous RPM auction, with more than 6,000 MW of nameplate wind and more than 8,300 MW of

[47] Ex SC-20, PJM, 2024/2025 RPM Base Residual Auction Results, p. 4. Accessed at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

[48] Ex SC-23, PJM, Interconnection Process Reform Task Force Update, May 11, 2021. Accessed at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210511/20210511-item-11-interconnection-process-reform-task-force-update.ashx.

nameplate solar PV clearing the market.[49] Additionally, recently proposed changes to PJM's capacity accreditation process are likely to have only moderate impacts on capacity prices, as the lower resource accreditation (which may drive a slight increase in supply needs) are being balanced by lower system reserve margins. These factors have combined to reduce PJM prices from inordinately high historical levels down to what was seen in the 2022/2023 BRA clearing prices in April of 2021 ($50/MW-Day) and the 2023/2024 BRA clearing prices in June of 2022 ($34.13/MW-Day), and they are likely to continue to reduce prices in future PJM auctions.

Q What is the gross avoidable cost for existing generation in PJM and how does it compare to the costs paid under the ICPA?

A The gross avoidable cost is a resource-specific, bottom-up cost estimate of the gross fixed cost associated with operating a representative plant.[50] PJM calculates an updated gross avoidable cost rate (ACR) every four years and uses it to determine default offer thresholds for the capacity market.[51] The ACR's purpose is to mitigate market power in the PJM capacity market. Previously, offer caps were set based on Net CONE (with various adjustments), but in 2021 FERC found the rates to be unrealistically high and switched to

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[49] Ex SC-20, PJM 2024/2025 RPM Base Residual Auction Results, p. 11. Accessed at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx; PJM ELCC Class Ratings for 2024/2025 Available at https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2024-2025.ashx.

[50] Ex SC-22, Gross Avoidable Costs for Existing Generation, Prepared for PJM by Brattle Group. January 9, 2023, p. iii. Available at https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230223/20230223-item-02---4-brattle-gross-avoidable-costs-for-existing-generation-report.ashx.

[51] *Ibid.*

the ACR.[52] The 2023 report contains ACRs for nuclear, coal, natural gas combined-cycle CC and combustion turbine units, oil and gas steam turbined units, onshore wind, and solar PV.[53] I present the ACR for a coal plant, CC and CT unit here to show the $/MW-day cost of a representative existing coal plant and combustion turbine plant.

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 its 2022 PSCR Plan Case, U-21052, and in its 2021 PSCR Reconciliation Case, U-20805. I do not believe the transfer price is an appropriate benchmark because it represents the levelized cost of a new combined-cycle 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 $29.40 million per year in excess of the cost of these long-term supply comparisons.

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[52] *Id.* at 6.

[53] *Id.* at v.

D. I&M's IRP analysis on OVEC is an outlier among nearly half a dozen forward-going analysis which all confirm my findings that OVEC is projected to be uneconomic to operate going forward.

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 was $54 million more costly than continuing under it until 2040.
April, 2019	FirstEnergy Solutions,[2,3]	Forward-looking analysis of ICPA through 2040; found $267 million in losses relative to market for I&M's share of OVEC.
December, 2018	Moody's Analytics[4]	Assessment of the ICPA; found annual losses of $16–$20 million.
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 2030's and on a present-value basis the ICPA was projected to have a net negative value.

Source: [1] Ex SC-24 Case No. U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf; [2] Ex SC-25 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. (Doc 44. Filed Apr. 1, 2018), In re FirstEnergy

Solutions Corp., No. 18-50757 (AMK) (Bankr. ND.Ohio); [3] Ex SC-26 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 SC-27 Moody's Investors Service. December 2018. Credit Opinion: Ohio Valley Electric Cooperative.; [5] Ex SC-28 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; Case No. U-20459, I&M Response to Sierra Club Request 1-46.

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.[54] 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.[55] The Company subsequently updated its analysis for rebuttal testimony to correct numerous errors and found a cost savings of $54 million.[56] In his testimony in this case, I&M witness Jason Stegall claims that the IRP analysis demonstrated that OVEC remains a more economic resource than potential replacements.[57]

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.

[54] Case No. U-20529, Order, May 13, 2021, p. 22.

[55] Ex SC-24, Case No. U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf.

[56] Case No. U-21189, Modeling Rebuttal Testimony of Jason Stegall, p. 3.

[57] Direct Testimony of Jason Stegall, pp. 7–8.

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 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).[58] 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

[58] Ex SC-24, Case No. U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.pdf; *see* Case No. U-21189, Modeling Rebuttal Testimony of Jason Stegall, p. 3.

year. Fifth, the capacity factors from the stochastic analysis the Company used to develop its generation assumptions for this IRP analysis[59] are unlikely to match the low utilization levels I&M projected during this current PSCR plan, for reasons discussed above. And finally, I&M's IRP analysis is not likely to include the costs to comply with the EPA's recently issued Good Neighbor Plan final rule to reduce inter-state ozone pollution, which will increase compliance costs on all OVEC units during this PSCR period. The analysis also predates the proposed Greenhouse Gas Regulations proposed under Section 111 of the *Clean Air Act* and therefore does not contemplate the impacts that increased carbon regulation will have on continued operation of the plants.

Q Explain the newly issued Good Neighbor Plan and how it will impact environmental compliance costs at OVEC.

A The Good Neighbor Plan's initial nitrogen oxides (NO_X) reductions requirements will take effect by August 2024 and more-stringent reductions will be implemented ahead of the 2026 ozone season.[60] It is not possible to determine OVEC's precise cost of annual compliance because two factors remain unknown: the cost of NO_X allowances in future years and each unit's rolling three-year heat input in the year leading up to compliance. For illustrative purposes, I have estimated the cost of compliance for ozone season 2027, assuming that (1) NO_X allowances cost $48,000, the highest trade price from 2022's ozone

[59] Ex SC-12, I&M Response to Sierra Club Request 3-12, SC 3-12 Confidential Attachment 1.

[60] Ex SC-32, U.S. EPA, EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet, available at: https://www.epa.gov/system/files/documents/2023-03/Final%20Good%20Neighbor%20Rule%20Fact%20Sheet_0.pdf.

season,[61] (2) OVEC's NO_X allowances do not decrease from EPA's calculation of the 2025 allowance (a conservative assumption). With these assumptions, I calculate that Kyger Creek will incur approximately an $8 million operating cost and Clifty Creek will incur roughly $35 million in operating costs each year beginning in 2026–2027 and thereafter. This estimate is conservative because, while Ohio's and Indiana's statewide allocations decline from the 2025,[62] I have applied none of that decline to OVEC's 2025 allocation.

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.[63] 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 debt projections show that OVEC is planning to recover [[[redacted]]] percent of the projected debt balance (as of December 31, 2023) through demand charges during the PSCR period (2024–2028) and [[[redacted]]] percent before the end of 2030.[64] Figure 4 below shows how OVEC plans to [[[redacted]]

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[61] Ex SC-31, Michael Ball, *Viewpoint: NOx could rise on new regulations*, Argus Media, (December 29, 2022), available at: https://www.argusmedia.com/en/news/2405066-viewpoint-nox-could-rise-on-new-regulations?backToResults=true.

[62] Ex SC-29, U.S. EPA, State Budgets for the Good Neighbor Plan, available at: https://www.epa.gov/csapr/state-budgets-under-good-neighbor-plan-2015-ozone-naaqs.

[63] Ex SC-24, Case No. U-21052, I&M Response to Sierra Club 1-09, SC 1-09 OVEC Stakeholder Meeting Slide.

[64] Ex SC-12, I&M Response to SC 3-12, SC 3-12 Confidential Attachment 1.

[redacted]]].[65] 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, absent action from the Commission it will already have recovered the majority of its share of the remaining balance from its ratepayers.

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

[redacted]

Source: Ex SC-12, I&M Response to Sierra Club 3-12, SC 3-12 CONFIDENTIAL Attachment 1.

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 Michigan customers for its purchase of power from OVEC under the ICPA, I&M ratepayers will be forced to pay $101.5 million more than the market value of the power over the next five years. These findings were confirmed by the analyses conducted by several other reputable consulting firms over the past few years. This continues a trend

[65] *Ibid.*

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.

E. OVEC has invested over $[[redacted]]million in environmental upgrades at the OVEC plants, some of which will be recovered from Michigan ratepayers during the PSCR period, all while I&M is projecting plummeting capacity factors for the OVEC plants

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

A 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. I&M acknowledged that costs associated with CCR and ELG capital projects are included in the forecasted demand charges for 2024–2028.[66] The Company did not provide specific amounts, stating that the demand charge forecast is created by OVEC, and that I&M does not have that information.[67] But the Company did provide an [[[redacted]]][68] Additionally, I&M provided [[[redacted]]][69]

[66] *See* I&M Response to Sierra Club Request 3-14.

[67] *See* I&M Response to Sierra Club Request 3-14; *see also* I&M Response to Sierra Club Request 3-15.

[68] Ex SC-13, I&M Response to Sierra Club Request 3-16, SC 1-16 Confidential Attachment 1, p. 9.

[69] Ex SC-12, I&M Response to Sierra Club Request 3-12, SC 1-12 Confidential Attachment 1, tab WP Power Cost Summary 2022–2040.

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 $[[[redacted]]] million in costs that the OVEC board approved[70] and that OVEC is planning to charge its sponsoring companies for the environmental projects is $[[[redacted]]] 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).[71] This means I&M is charging its customers $[[[redacted]]] million over the last two years and the current year (2024) for the possibility that it may save $54 million a decade for 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 capacity over just the next five years. The Company's own data shows these losses are projected to be $101.5 million between 2024–2028. These projections match closely 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).

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

[70] *Ibid.*

[71] Case No. U-21189, Modeling Rebuttal Testimony of Jason Stegall, p. 3.

the OVEC plants were discussed in I&M's 2019 IRP (which, incidentally, was never approved by the Commission).[72]

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 decision 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.[73]

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

A OVEC stated in its [[[redacted]]].[74] In OVEC's 2022 Annual Report, OVEC stated that it was on track to complete closure of its unlined impoundments receiving CCR material by the third quarter of 2023 and that it expects to meet its ELG requirements.

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

[72] *See* Case No. U-21189, I&M 2019 Integrated Resource Plan.

[73] Case No. U-20804, Direct Testimony of Devi Glick, p. 28.

[74] Ex SC-13, I&M Response to Sierra Club Request 3-16, SC 3-16 Confidential Attachment 1.

period on the denial ended on March 25, 2022, and the EPA has taken no final action on the denial.[75] OVEC filed a similar demonstration application for Kyger Creek in November 2020 and has also yet to receive a final ruling. 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, if EPA's March 2023 proposed ELG rule update is finalized as proposed, OVEC would have to install a further round of ELG compliance projects because its current plan to comply with these ELG's bottom ash and flue-gas desulfurization ("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 effluent limits. This is scheduled to be installed by December 2025.[76] 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

[75] Ex SC-15, OVEC 2022 Annual Report, pp. 32–33.

[76] Ex SC-30, Clifty Creek NPDES Permit No. IN0001759 Application, Nov. 29, 2022, pp. 97-98. Available at https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83395202&dDocName=83397697&Rendition=web&allowInterrupt=1&noSaveAs=1.

wastewater waste streams.[77] 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,[78] 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's 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 reign to recover OVEC's debt from Michigan customers through the PSCR factor.

[77] 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.

[78] 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. I&M is projecting here that the OVEC units' utilizations will fall from just above 50 percent in 2023 to around 6 percent by 2028.[79]

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.

F. 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

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

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[79] Calculated based on Exhibit IM-17 (SAS-4); Ex SC-3, I&M Response to Sierra Club Request 1-15, SC 1-15 Attachment 1; Ex SC-7, Indiana Michigan Response to Sierra Club Request 1-20, Supplemental Attachment SC 1-20.

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 2024–2028.

IV. I&M IS IMPRUDENTLY OPERATING THE ROCKPORT UNITS, LEADING TO EXCESS COSTS TO ITS RATEPAYERS

A. *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. Unit 1 has a nameplate capacity of 1,320 MW and Unit 2 is 1,300 MW. Unit 1 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 at a 50- percent share each. This lease expired in December 2022. I&M is no longer entitled to energy from Unit 2.[80]

[80] Direct Testimony of Baker, p. 8.

AEG currently sells 100 percent of its share of Rockport Unit 1 back to I&M.[81] Previously, AEG sold 70 percent of its share of each Rockport unit back to I&M and 30 percent to Kentucky Power's ("KPCo") under a Unit Power sales agreement ("UPA"). KPCo's purchase from AEG also expired in December 2022, and I&M now takes the power from Unit 1 that was previously committed to KPCo.

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 the costs associated with the 50-percent share of Rockport 1 that it owns. The associated fuel costs are planned for in this PSCR docket and passed on directly to customers as fuel costs through fuel clauses. The remaining unit costs are passed on to ratepayers through rate cases and other dockets.

I&M also is responsible for the costs associated with AEG's portion of Rockport it purchases through a Unit Power Agreement (100 percent after 2022). But 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.

In total, I&M is responsible for 100 percent of the costs associated with Rockport Unit 1. I&M is also responsible for the costs associated with Rockport Unit 2 but I&M is no longer permitted to seek recovery of the energy portion of those costs in rates or the PSCR.[82]

[81] *Ibid*.

[82] *Id*.

B. 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.[83]

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

A Rockport power is projected to be extremely expensive on a forward-going basis. This is in large part due to the large drop in Rockport's projected capacity factor. Adding to the cost, the Company currently has more committed tons of coal than what is called for in its coal forecast.[84] To address this oversupply, I&M has amended two contracts to defer delivery of coal: [[redacted]]. It is unclear how many tons this applies to and therefore the aggregate cost of deferral.[85]

[83] *Id*, pp. 20–21.

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

[85] Ex SC-2, I&M Response to Sierra Club Request 1-09(b).

Table 5. Total power cost for Rockport 1 in current and prior PSCR dockets

Year	Actual historical PSCR costs	PSCR 2024–2028 Total Power Cost ($/MWh)
2017	$58.56	
2018	$57.15	
2019	$75.35	
2020	$122.24	
2021	$128.31	
2022	$110.90	
2023	$149.90	
2024		$121.01
2025		$121.55
2026		$142.76
2027		$152.07
2028		$208.60

Source: Exhibit IM-16 (SAS-3); Exhibit IM-17(SAS-4);Ex SC-10, I&M Response to Sierra Club Request 3-05, SC 3-5 Attachment 1; 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)

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

A No. As shown in CONFIDENTIAL Figure 5, I project that Rockport Unit 1 will 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.[86] This works out to $68.7 Million over the PSCR period, or $16.6 Million per year for the Michigan jurisdictional share of Rockport Unit 1.

[86] Ex SC-8, I&M Response to Sierra Club Request 3-02, SC 3-02 Attachment 1; Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachment 2; Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 Confidential Attachment 3; *see* I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, Line 15; Ex SC-11, I&M Response to Sierra Club Request 3-06, SC 3-6 Confidential Attachment 1.

CONFIDENTIAL Figure 5. Rockport 1 projected net revenues, 2024–2028

[redacted]

Source: Ex SC-8, I&M Response to Sierra Club Request 3-02, SC 3-02 Attachment 1; Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 CONFIDENTIAL Attachment 2; Ex SC-4, I&M Response to Sierra Club Request 1-16, SC 1-16 CONFIDENTIAL Attachment 3; see I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, Line 15; Ex SC-11, I&M Response to Sierra Club Request 3-06, SC 3-6 Confidential Attachment 1.

Q How did you calculate these values?

A The Company provided projected generation[87] and a break-down of fuel and demand expenses associated with AEG's portion of Rockport 1 over the next five years. I assumed that the fuel expenses[88] represented Rockport's variable costs and the demand expenses[89] 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

[87] Ex SC-11, I&M Response to Sierra Club Request 3-06, SC 3-06 Confidential Attachment 1.

[88] I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, Line 15.

[89] *Ibid.*

unit. I calculated capacity revenue using the ICAP values[90] I&M provided and the capacity price forecast from I&M's capacity market forecast.[91] I added that to energy market revenue, which I calculated based on I&M's power market prices.[92] I compared total costs to total revenues to find the net revenues.

Q Why is Rockport 1 projected to earn so little energy market revenue going forward?

A I&M is projecting a forward-going capacity factor at Rockport 1 of less than 10 percent for the years 2025–2028.[93] This an extremely low utilization level and clearly shows how uneconomic this unit is to operate. But a lower capacity factor also means that there are fewer MWh over which to spread the fixed costs. And as I show in CONFIDENTIAL Figure 5, the unit's fixed costs are extremely high relative to its utilization level.

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

[90] Ex SC-8, I&M Response to Sierra Club 3-02, SC 3-02 Attachment 1.

[91] Ex SC-4, I&M Response to Sierra Club 1-16, SC 1-16 CONFIDENTIAL Attachment 2.

[92] Ex SC-4, I&M Response to Sierra Club 1-16, SC 1-16 CONFIDENTIAL Attachment 3.

[93] I&M Response to Staff Request 1-01, Attachment 4: U-21427 Exh 14-17 Workpaper, Line 15.

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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Devi Glick, Senior Principal

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, May 2022 – Present; *Principal Associate*, June 2021 – May 2022; *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*

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Georgia Public Service Commission (Docket No. 55378): Direct Testimony of Devi Glick and Lucy Metz in Re: Georgia Power Company's 2023 Integrated Resource Plan Update. On behalf of Sierra Club. February 15, 2024.

Louisiana Public Service Commission (Docket No. U-36923): Direct Testimony of Devi Glick in the Application of Cleco Power LLC for: (1) Implementation of changes in rates to be effective July 1, 2024; and (2) extension of existing formula rate plan. On behalf of Sierra Club. February 5, 2024.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Supplemental Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. January 29, 2024.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Surrebuttal Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. November 17, 2023.

Public Utilities Commission of Ohio (Case No. 21-477-EL-RDR): Direct Testimony of Devi Glick in the Matter of the OVEC Generation Purchase Rider Audits Required by 4928.148 for Duke Energy Ohio, Inc. the Dayton Power and Light Company, and AEP Ohio. On behalf of Union of Concerned Scientists and the Citizens Utility Board. October 10, 2023.

Public Service Commission of South Carolina (Docket No. 2023-154-E): Direct Testimony of Devi Glick in re: 2023 Integrated Resource Plan for the South Carolina Public Service Authority. On behalf of Sierra Club. September 22, 2023.

Public Utilities Commission of Ohio (Case No. 20-165-EL-RDR): Direct Testimony of Devi Glick in the matter of the review of the Reconciliation Rider of the Dayton Power and Light Company. On behalf of Office of the Ohio Consumers' Counsel. September 12, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00066): Direct Testimony of Devi Glick in re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Virginia Code to §56-597 *et seq.* On behalf of Sierra Club. August 8, 2023.

Public Utility Commission of Texas (PUC Docket No. 54634): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. August 4, 2023

Arizona Corporation Commission (Docket No. E-1345A-22-0144): Surrebuttal Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. July 26, 2023.

Arizona Corporation Commission (Docket No. E-01345A-22-0144): Direct Testimony of Devi Glick in the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of Sierra Club. June 5, 2023.

Virginia State Corporation Commission (Case No. PUR-2023-00005): Direct Testimony of Devi Glick in the Petition of Virginia Electric & Power Company for revision of rate adjustment clause, Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 23, 2023.

New Mexico Public Regulation Commission (Case No, 22-00286-UT): Direct Testimony of Devi Glick in the matter of Southwestern Public Service Company's application for: (1) Revisions of its retail rates under advance no. 312; (2) Authority to abandon the Plant X Unit 1, Plant X Unit 2, and Cunningham Unit 1 Generating Stations and amend the abandonment date of the Tolk Generating Station; and (3) other associated relief. On behalf of Sierra Club. April 21, 2023.

Michigan Public Service Commission (Case No. U-20805): Direct Testimony of Devi Glick in the matter of the Application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2021. On behalf of Michigan Attorney General. April 17, 2023.

Michigan Public Service Commission (Case No. U-21261): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval to implement a Power Supply Cost Recovery Plan for the twelve months ending December 31, 2023. On Behalf of Sierra Club. March 23, 2023.

New Mexico Public Regulation Commission (Case No. 19-00099-UT / 19-00348-UT): Direct Testimony of Devi Glick in the matter of El Paso Electric Company's Application for Approval of Long-Term

Purchased Power Agreements with Hecate Energy Santa Teresa, LLC, Buena Vista Energy, LLC, and Canutillo Energy Center LLC. On Behalf of New Mexico Office of the Attorney General, January 23, 2023.

Arizona Corporation Commission (Docket No. E-01933A-22-0107): Direct Testimony of Devi Glick 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 the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona for related approvals. On Behalf of Sierra Club. January 11, 2023.

New Mexico Public Regulation Commission (Case No. 22-00093-UT): Direct Testimony of Devi Glick in the amended application for approval of El Paso Electric Company's 2022 renewable energy act plan pursuant to the renewable energy act and 17.9.572 NMAC, and sixth revised rate no. 38-RPS cost rider. On Behalf of New Mexico Office of the Attorney General, January 9, 2023.

Iowa Utilities Board (Docket No. RPU-2022-0001): Supplemental Direct and Rebuttal Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. November 21, 2022.

Public Utility Commission of Texas (PUC Docket No. 53719): Direct Testimony of Devi Glick in the application of Entergy Texas, Inc. for authority to change rates. On behalf of Sierra Club. October 26, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00051): Direct Testimony of Devi Glick in re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Virginia Code §56-597 *et seq*. On behalf of Sierra Club. September 2, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Surrebuttal Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. August 16, 2022.

Iowa Utilities Board (Docket No. RPU-2022-0001): Direct Testimony of Devi Glick in MidAmerican Energy Company Application for a Determination of Ratemaking Principles. On behalf of Environmental Intervenors. July 29, 2022.

Public Service Commission of the State of Missouri (Case No. ER-2022-0129, Case No. ER-2022-0130): Direct Testimony of Devi Glick in the matter of Every Missouri Metro and Evergy Missouri West request for authority to implement a general rate increase for electric service. On behalf of Sierra Club. June 8, 2022.

Virginia State Corporation Commission (Case No. PUR-2022-00006): Direct Testimony of Devi Glick in the petition of Virginia Electric & Power Company for revision of rate adjustment clause: Rider E, for the recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia. On behalf of Sierra Club. May 24, 2022.

Oklahoma Corporation Commission (Case No. PUD 202100164): Direct Testimony of Devi Glick in the matter of the application of Oklahoma gas and electric company for an order of the Commission authorizing application to modify its rates, charges, and tariffs for retail electric service in Oklahoma. On behalf of Sierra Club. April 27, 2022.

Public Utility Commission of Texas (PUC Docket No. 52485): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. March 25, 2022.

Public Utility Commission of Texas (PUC Docket No. 52487): Direct Testimony of Devi Glick in the application of Entergy Texas Inc. to amend its certificate of convenience and necessity to construct Orange County Advanced Power Station. On behalf of Sierra Club. March 18, 2022.

Michigan Public Service Commission (Case No. U-21052): Direct Testimony of Devi Glick in the matter of the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and Factors (2022). On Behalf of Sierra Club. March 9, 2022.

Arkansas Public Service Commission (Docket No. 21-070-U): Surrebuttal Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for approval of a general change in rate and tariffs. On behalf of Sierra Club. February 17, 2022.

New Mexico Public Regulation Commission (Case No. 21-00200-UT): Direct Testimony of Devi Glick in the Matter of the Southwestern Public Service Company's application to amend its certifications of public convenience and necessity to convert Harrington Generation Station from coal to natural gas. On behalf of Sierra Club. January 14, 2022.

Public Utilities Commission of Ohio (Case No. 18-1004-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Power Purchase Agreement Rider of Ohio Power Company for 2018 and 2019. On behalf of the Office of the Ohio Consumer's Counsel. December 29, 2021.

Arkansas Public Service Commission (Docket No. 21-070-U): Direct Testimony of Devi Glick in the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs. On behalf of Sierra Club. December 7, 2021.

Michigan Public Service Commission (Case No. U-20528): Direct Testimony of Devi Glick in the matter of the Application of DTE Electric Company for reconciliation of its power supply cost recovery plan (Case No. U-20527) for the 12-month period ending December 31, 2020. On behalf of Michigan Environmental Council. November 23, 2021.

Public Utilities Commission of Ohio (Case No. 20-167-EL-RDR): Direct Testimony of Devi Glick in the Matter of the Review of the Reconciliation Rider of Duke Energy Ohio, Inc. On behalf of The Office of the Ohio Consumer's Counsel. October 26, 2021.

Public Utilities Commission of Nevada (Docket No. 21-06001): Phase III Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. October 6, 2021.

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

North Carolina Utilities Commission (Docket No. E-2, Sub 1272): Direct Testimony of Devi Glick in the matter of the application of Duke Energy Progress, LLC pursuant to N.C.G.S § 62-133.2 and commission R8-5 relating to fuel and fuel-related change adjustments for electric utilities. On behalf of Sierra Club. August 31, 2021.

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

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

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

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

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

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

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

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

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

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

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

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

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Reply 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.

Public Utility Commission of Texas (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): 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.

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. March 23, 2018.

Resume updated August 2023

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-21427

DATA REQUEST NO. 1-15-SC

Request

Provide the monthly Installed Capacity (“ICAP”) value for:
a. OVEC units for 2018 – 2023 (historic).
b. OVEC units for the PSCR plan year and five-year forecast period 2024 – 2027 (projected).

Response

a. I&M objects to this request on the grounds it is overly broad, unduly burdensome, not relevant, and not reasonably calculated to lead to the discovery of admissible evidence because it seeks information outside the PSCR forecast period.

Subject to and without waiving I&M’s objections, please see SC-CUB 1-15 Attachment 2.xlsx

b. Please see SC 1-15 Attachment 1.xlsx

Preparer
Baker

As to Objection
Legal

Indiana Michigan Power Company
Case U-21427
SC 1-15 Attachment 1

INDIANA MICHIGAN POWER COMPANY
I&M's SHARE OF PROJECTED INSTALLED CAPACITY
(MW)

	Clifty 1	Clifty 2	Clifty 3	Clifty 4	Clifty 5	Clifty 6	Kyger 1	Kyger 2	Kyger 3	Kyger 4	Kyger 5
Jan-24	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Feb-24	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Mar-24	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Apr-24	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
May-24	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Jun-24	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Jul-24	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Aug-24	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Sep-24	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Oct-24	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Nov-24	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
Dec-24	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Jan-25	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Feb-25	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Mar-25	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Apr-25	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
May-25	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Jun-25	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Jul-25	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Aug-25	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Sep-25	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Oct-25	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Nov-25	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
Dec-25	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Jan-26	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Feb-26	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Mar-26	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Apr-26	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
May-26	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Jun-26	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Jul-26	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Aug-26	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Sep-26	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Oct-26	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Nov-26	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
Dec-26	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Jan-27	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Feb-27	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Mar-27	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Apr-27	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
May-27	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Jun-27	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Jul-27	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Aug-27	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Sep-27	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Oct-27	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Nov-27	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
Dec-27	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Jan-28	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Feb-28	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.712
Mar-28	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532
Apr-28	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
May-28	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Jun-28	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Jul-28	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Aug-28	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99	14.99
Sep-28	15.17	15.17	15.17	15.17	15.17	15.17	15.17	14.99	14.99	14.99	14.99
Oct-28	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.351	15.351	15.351	15.351
Nov-28	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532	15.532
Dec-28	15.712	15.712	15.712	15.712	15.712	15.712	15.712	15.532	15.532	15.532	15.532

Indiana Michigan Power Company
I&M Share Installed Capacity (ICAP)

	2018	2019		2020		2021		2022	2023	2023
	Jan - Dec	Jan - May	Jun - Dec	Jan - May	Jun - Dec	Jan - May	Jun - Dec	Jan - Dec	Jan - May	Jun - Dec
OVEC ICPA	163	163	168.9	168.9	165.8	165.8	165.9	165.9	165.9	166

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-21427

DATA REQUEST NO. 1-20-SC

Request

Produce the workpapers and all data used to create Table JMS-1, in electronic Excel format.

Response

Please see SC 1-20 Attachment 1 for the requested information.

Preparer
Stegall

Indiana Michigan Power Company
Workpaper for Table JMS-1

	Energy Revenues	Energy Charge	Net Margin
Jan 2017	$2,292,947	$1,958,792	$334,155
Feb	$2,074,502	$2,041,717	$32,785
Mar	$3,180,844	$2,516,284	$664,560
Apr	$1,935,622	$1,687,670	$247,952
May	$1,430,521	$1,254,953	$175,568
Jun	$2,184,187	$1,934,239	$249,948
Jul	$2,758,508	$2,146,206	$612,302
Aug	$2,373,536	$2,091,025	$282,511
Sep	$1,679,230	$1,318,937	$360,293
Oct	$1,938,282	$1,636,331	$301,951
Nov	$2,385,553	$2,003,463	$382,089
Dec	$3,210,924	$2,480,126	$730,798
Jan 2018	$4,634,744	$2,201,990	$2,432,754
Feb	$1,970,333	$1,891,001	$79,332
Mar	$2,913,591	$2,038,271	$875,319
Apr	$2,426,270	$1,588,687	$837,583
May	$1,932,982	$1,374,834	$558,149
Jun	$2,479,543	$1,887,062	$592,481
Jul	$2,939,189	$2,148,571	$790,618
Aug	$2,757,437	$2,060,939	$696,498
Sep	$2,393,560	$1,729,063	$664,496
Oct	$1,972,823	$1,276,276	$696,548
Nov	$3,322,595	$1,988,586	$1,334,009
Dec	$2,885,259	$2,228,542	$656,718
Jan 2019	$2,827,877	$2,152,952	$674,925
Feb	$2,060,612	$1,836,187	$224,425
Mar	$2,555,122	$2,114,271	$440,851
Apr	$1,135,818	$1,136,458	($640)
May	$1,547,839	$1,608,660	($60,822)
Jun	$1,721,151	$1,792,517	($71,367)
Jul	$2,509,929	$2,170,400	$339,530
Aug	$2,024,649	$2,008,555	$16,093
Sep	$1,984,088	$1,748,783	$235,305
Oct	$2,083,410	$1,935,855	$147,555
Nov	$2,622,153	$2,100,142	$522,012
Dec	$2,011,993	$2,070,091	($58,098)
Jan 2020	$1,657,029	$1,774,282	($117,253)
Feb	$1,321,633	$1,642,742	($321,109)
Mar	$968,762	$1,423,887	($455,125)
Apr	$501,605	$974,603	($472,998)
May	$635,744	$978,732	($342,989)
Jun	$1,327,335	$1,609,964	($282,629)
Jul	$1,911,110	$1,837,940	$73,169

	Energy Revenues	Energy Charge	Net Margin
Aug	$1,596,451	$1,715,507	($119,056)
Sep	$1,108,804	$1,396,224	($287,420)
Oct	$1,181,276	$1,224,347	($43,072)
Nov	$1,471,474	$1,712,394	($240,920)
Dec	$2,234,766	$2,197,204	$37,562
Jan 2021	$2,064,318	$2,039,113	$25,205
Feb	$3,787,158	$2,034,989	$1,752,169
Mar	$1,673,016	$1,746,123	($73,107)
Apr	$1,810,655	$1,612,470	$198,185
May	$1,325,103	$1,179,036	$146,066
Jun	$2,120,596	$1,680,532	$440,064
Jul	$3,164,758	$2,233,090	$931,668
Aug	$3,522,268	$2,268,838	$1,253,430
Sep	$3,438,177	$1,997,082	$1,441,094
Oct	$2,182,772	$1,074,755	$1,108,016
Nov	$2,287,365	$970,744	$1,316,621
Dec	$2,104,300	$1,586,885	$517,416
Jan 2022	$4,687,702	$2,195,831	$2,491,871
Feb	$3,626,754	$1,989,995	$1,636,759
Mar	$2,711,863	$1,629,462	$1,082,402
Apr	$4,099,732	$1,829,485	$2,270,247
May	$4,878,739	$1,902,302	$2,976,437
Jun	$8,392,250	$2,800,141	$5,592,109
Jul	$6,753,447	$2,820,849	$3,932,598
Aug	$7,916,499	$3,277,512	$4,638,987
Sep	$5,300,874	$2,506,720	$2,794,154
Oct	$2,369,712	$1,649,007	$720,705
Nov	$3,504,825	$2,285,380	$1,219,445
Dec	$7,353,014	$2,928,697	$4,424,317
Jan 2023	$2,580,086	$2,318,994	$261,092
Feb	$1,271,851	$1,492,508	($220,657)
Mar	$1,891,236	$2,375,667	($484,431)
Apr	$2,003,128	$2,363,792	($360,664)
May	$1,261,089	$1,612,841	($351,751)
Jun	$1,831,865	$2,327,616	($495,751)
Jul	$2,793,380	$2,567,309	$226,071
Aug	$2,149,608	$2,471,768	($322,159)
Sep	$1,413,519	$1,801,552	($388,033)
Oct	$2,080,808	$2,108,742	($27,934)
Nov	$2,372,107	$2,502,937	($130,830)
Dec	$2,190,404	$3,109,159	($918,755)
2017	$27,444,655	$23,069,742	$4,374,913
2018	$32,628,326	$22,413,821	$10,214,504
2019	$25,084,642	$22,674,872	$2,409,770
2020	$15,915,987	$18,487,826	($2,571,839)

	Energy Revenues	Energy Charge	Net Margin
2021	$29,480,487	$20,423,658	$9,056,829
2022	$61,595,412	$27,815,382	$33,780,030
2023	$23,839,081	$27,052,885	($3,213,804)
			$54,050,403

Indiana Michigan Power Company
OVEC Billing Data
January 2013 to August 2023

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Jan 2013	65,346	$2,049,966	$1,626,488	$106,266		$3,782,720
Feb	58,567	$1,789,333	$1,986,378	$102,700		$3,878,412
Mar	48,063	$1,458,139	$2,242,416	$98,322		$3,798,877
Apr	46,663	$1,454,535	$3,096,788	$96,926		$4,648,248
May	61,233	$1,837,542	$2,633,022	$103,149		$4,573,714
Jun	79,057	$2,336,639	$1,937,124	$109,621		$4,383,384
Jul	86,197	$2,536,226	$1,871,042	$111,986		$4,519,254
Aug	69,863	$2,117,036	$1,951,189	$106,625		$4,174,851
Sep	56,065	$1,755,417	$2,057,689	$101,817		$3,914,923
Oct	72,079	$2,206,050	$2,502,011	$107,807		$4,815,869
Nov	60,331	$1,881,544	$2,572,956	$103,142		$4,557,642
Dec	78,500	$2,235,204	$2,504,466	$110,253		$4,849,923
Jan 2014	91,233	$2,506,101	$1,500,861	$115,395		$4,122,357
Feb	86,687	$2,390,789	$1,769,031	$113,014		$4,272,835
Mar	85,798	$2,357,287	$2,028,630	$112,167		$4,498,084
Apr	50,486	$1,464,012	$2,391,845	$98,824		$3,954,681
May	54,476	$1,561,715	$2,097,283	$100,400		$3,759,398
Jun	74,640	$2,020,747	$1,681,400	$108,857		$3,811,004
Jul	78,411	$2,226,123	$1,638,739	$110,246		$3,975,108
Aug	72,121	$2,104,602	$1,750,930	$107,746		$3,963,278
Sep	75,047	$2,189,949	$1,853,251	$108,545		$4,151,746
Oct	46,585	$1,320,808	$2,181,359	$97,669		$3,599,836
Nov	62,700	$1,757,492	$1,863,656	$103,658		$3,724,806
Dec	75,618	$2,158,926	$2,735,824	$110,026		$5,004,775
Jan 2015	72,501	$1,899,272	$1,547,597	$109,246		$3,556,115
Feb	65,617	$1,720,027	$1,565,307	$105,027		$3,390,362
Mar	71,226	$1,899,161	$1,981,141	$107,897		$3,988,199
Apr	55,387	$1,490,052	$2,395,423	$101,130		$3,986,606
May	49,999	$1,505,223	$1,842,171	$91,925		$3,439,319
Jun	55,921	$1,654,843	$1,691,356	$100,677		$3,446,876
Jul	54,362	$1,651,366	$1,965,086	$100,085		$3,716,537
Aug	65,907	$1,787,529	$1,871,847	$104,923		$3,764,299
Sep	62,304	$1,820,109	$1,847,212	$101,736		$3,769,057
Oct	47,873	$1,392,335	$1,968,277	$98,916		$3,459,527
Nov	25,557	$811,597	$2,247,303	$89,352		$3,148,253
Dec	22,090	$779,366	$2,412,632	$88,226		$3,280,224
Jan 2016	52,558	$1,515,951	$1,531,039	$100,638		$3,147,628
Feb	44,281	$1,236,126	$1,617,773	$97,814		$2,951,713
Mar	29,756	$773,142	$1,892,817	$92,735		$2,758,695
Apr	32,278	$923,902	$2,567,807	$91,412		$3,583,121

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
May	48,478	$1,337,521	$1,986,197	$99,140		$3,422,858
Jun	80,535	$2,125,263	$1,524,541	$110,432		$3,760,236
Jul	88,148	$2,313,550	$1,712,436	$114,173		$4,140,159
Aug	84,446	$2,199,008	$1,796,092	$111,469		$4,106,569
Sep	84,528	$2,199,215	$1,683,785	$111,535		$3,994,535
Oct	46,778	$1,264,218	$2,203,944	$96,544		$3,564,706
Nov	60,683	$1,646,298	$2,151,153	$102,148		$3,899,599
Dec	91,108	$2,428,505	$2,415,220	$113,963		$4,957,689
Jan 2017	77,915	$1,958,792	$1,756,404	$109,355	$186	$3,824,737
Feb	83,113	$2,041,717	$1,925,768	$110,573	$784	$4,078,843
Mar	103,611	$2,516,284	$1,998,440	$118,002	$186	$4,632,911
Apr	66,155	$1,687,670	$2,442,300	$104,128	$186	$4,234,283
May	47,723	$1,254,953	$2,678,596	$96,421	$855	$4,030,825
Jun	78,688	$1,934,239	$1,808,936	$108,755	$186	$3,852,116
Jul	90,408	$2,146,206	$2,046,243	$113,290	$186	$4,305,923
Aug	86,215	$2,091,025	$1,939,160	$111,466	$831	$4,142,482
Sep	52,935	$1,318,937	$2,589,294	$98,536	$186	$4,006,953
Oct	65,446	$1,636,331	$2,561,559	$103,824	$186	$4,301,900
Nov	82,256	$2,003,463	$2,239,373	$110,684	$780	$4,354,300
Dec	103,155	$2,480,126	$2,007,877	$118,188	$186	$4,606,376
Jan 2018	94,970	$2,201,990	$1,828,115	$115,319	$190	$4,145,614
Feb	74,367	$1,891,001	$1,922,764	$106,826	$798	$3,921,390
Mar	92,426	$2,038,271	$2,108,377	$114,492	$190	$4,261,331
Apr	71,592	$1,588,687	$2,810,074	$106,423	$190	$4,505,375
May	56,548	$1,374,834	$2,748,094	$100,280	$806	$4,224,014
Jun	81,677	$1,887,062	$2,014,513	$110,091	$190	$4,011,855
Jul	92,665	$2,148,571	$2,203,312	$114,368	$190	$4,466,442
Aug	87,958	$2,060,939	$2,185,845	$112,573	$1,031	$4,360,388
Sep	68,432	$1,729,063	$2,187,940	$103,476	$417	$4,020,897
Oct	56,741	$1,276,276	$2,562,668	$99,449	$190	$3,938,583
Nov	91,032	$1,988,586	$1,962,812	$110,328	$990	$4,062,716
Dec	90,022	$2,228,542	$2,951,098	$95,791	$19,651	$5,295,083
Jan 2019	91,218	$2,152,952	$2,094,810	$110,194	-$1,915	$4,356,041
Feb	78,170	$1,836,187	$2,034,957	$105,126	$24,981	$4,001,251
Mar	87,236	$2,114,271	$2,344,018	$109,083	$13,497	$4,580,869
Apr	42,097	$1,136,458	$2,918,177	$92,291	$28,319	$4,175,244
May	60,874	$1,608,660	$2,570,080	$98,898	$24,129	$4,301,767
Jun	72,564	$1,792,517	$2,029,810	$103,577	$25,653	$3,951,558
Jul	90,014	$2,170,400	$2,170,947	$109,947	$23,149	$4,474,442
Aug	79,026	$2,008,555	$2,140,937	$105,945	$18,888	$4,274,325
Sep	72,769	$1,748,783	$2,286,598	$103,401	$50,137	$4,188,920
Oct	78,634	$1,935,855	$2,388,985	$106,183	$38,334	$4,469,357
Nov	89,736	$2,100,142	$1,884,349	$109,800	$10,588	$4,104,878
Dec	84,508	$2,070,091	$2,441,030	$108,224	$26,989	$4,646,333

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Jan 2020	73,111	$1,774,282	$2,002,353	$103,859	$31,144	$3,911,638
Feb	64,814	$1,642,742	$1,939,210	$100,820	$33,116	$3,715,888
Mar	53,273	$1,423,887	$2,466,473	$96,633	$26,062	$4,013,055
Apr	30,105	$974,603	$2,635,093	$87,568	$28,325	$3,725,589
May	33,978	$978,732	$2,386,859	$88,915	-$251,480	$3,203,026
Jun	65,730	$1,609,964	$1,938,162	$102,441	$7,588	$3,658,155
Jul	73,949	$1,837,940	$2,150,072	$105,719	$10,518	$4,104,250
Aug	70,557	$1,715,507	$2,197,338	$104,073	-$1,852	$4,015,065
Sep	52,291	$1,396,224	$2,308,890	$96,881	$10,427	$3,812,422
Oct	45,990	$1,224,347	$2,547,592	$94,374	$13,366	$3,879,678
Nov	68,609	$1,712,394	$2,267,110	$103,728	$1,371	$4,084,602
Dec	89,069	$2,197,204	$3,231,200	$111,049	$2,250	$5,541,702
Jan 2021	83,379	$2,039,113	$1,962,282	$108,737	-$262	$4,109,870
Feb	81,771	$2,034,989	$2,427,275	$108,352	$3,543	$4,574,159
Mar	68,592	$1,746,123	$2,446,912	$103,331	-$1,071	$4,295,295
Apr	63,131	$1,612,470	$2,911,163	$103,331	$749	$4,627,713
May	47,249	$1,179,036	$2,627,270	$94,637	-$4,324	$3,896,619
Jun	64,231	$1,680,532	$2,599,049	$101,565	$1,414	$4,382,560
Jul	87,606	$2,233,090	$2,484,140	$110,666	-$1,215	$4,826,681
Aug	87,228	$2,268,838	$2,570,224	$110,707	$1,433	$4,951,202
Sep	77,676	$1,997,082	$2,205,617	$107,122	$7,752	$4,317,574
Oct	38,091	$1,074,755	$2,571,711	$91,581	$30,063	$3,768,111
Nov	36,200	$970,744	$2,549,683	$90,719	$25,795	$3,636,942
Dec	54,846	$1,586,885	$2,861,437	$98,081	$1,749	$4,548,152
Jan 2022	87,236	$2,195,831	$2,282,552	$95,356	$15,072	$4,588,811
Feb	76,459	$1,989,995	$2,276,659	$107,055	$14,576	$4,388,286
Mar	58,683	$1,629,462	$2,593,726	$99,798	$10,329	$4,333,315
Apr	63,142	$1,829,485	$3,076,675	$101,417	$4,493	$5,012,071
May	63,176	$1,902,302	$2,570,918	$101,445	-$2,066	$4,572,599
Jun	95,590	$2,800,141	$2,543,874	$114,447	$397	$5,458,860
Jul	78,063	$2,820,849	$2,317,302	$107,413	$18,602	$5,264,166
Aug	87,534	$3,277,512	$2,478,343	$111,215	$18,079	$5,885,150
Sep	64,749	$2,506,720	$2,401,440	$102,192	$8,421	$5,018,772
Oct	39,119	$1,649,007	$2,626,770	$92,005	$19,332	$4,387,114
Nov	62,247	$2,285,380	$2,448,805	$101,198	$20,725	$4,856,108
Dec	91,248	$2,928,697	$3,273,911	$112,773	-$84,423	$6,230,958
Jan 2023	70,614	$2,318,994	$2,086,361	$104,800	$16,109	$4,526,265
Feb	42,972	$1,492,508	$2,392,717	$93,557	$15,726	$3,994,509
Mar	63,440	$2,375,667	$2,568,966	$101,823	-$5,090	$5,041,366
Apr	65,264	$2,363,792	$2,917,880	$102,731	-$10,205	$5,374,197
May	41,447	$1,612,841	$2,840,725	$92,616	$81	$4,546,262
Jun	65,967	$2,327,616	$2,886,688	$102,724	$1,661	$5,318,688
Jul	72,203	$2,567,309	$2,454,507	$105,240	$42,812	$5,169,868
Aug	69,890	$2,471,768	$2,651,258	$104,378	$3,313	$5,230,717

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Sep	46,835	$1,801,552	$2,752,362	$95,007	$13,349	$4,662,270
Oct	57,593	$2,108,742	$3,052,797	$99,316	$7,079	$5,267,933
Nov	74,362	$2,502,937	$2,663,109	$106,099	$10,182	$5,282,327
Dec	81,561	$3,109,159	$3,184,612	$109,000	$8,264	$6,411,035

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 3
CASE NO. U-21427

DATA REQUEST NO. 3-02-SC

Request

Provide the monthly Installed Capacity ("ICAP") value for:
a. Rockport units for 2018-2023 (historic).
b. Rockport units for PSCR plan year and five-year forecast period 2024-2028 projected.

Response
a. Please see SC 3-02 Attachment 1 for the requested information.

b. Please see SC 3-2 Attachment 2.xlsx for the requested information for total Rockport 1.

Preparer
Baker

Indiana Michigan Power Company
I&M Share Installed Capacity (ICAP)

	2018	2019	2020		2021	2022		2023	
	Jan - Dec	Jan - Dec	Jan - May	Jun - Dec	Jan - Dec	Jan - Dec. 7	Dec. 8 - 31	Jan - May	Jun - Dec
Rockport Unit 1	1,117.8	1,117.8	1,117.8	1,119.9	1,119.9	1,119.9	1,317.5	1,317.5	1,317.5
Rockport Unit 2	1,105	1,105	1,105	1,105	1,105	1,105	0	0	0

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 3
CASE NO. U-21427

DATA REQUEST NO. 3-04-SC

Request

With respect to I&M's share of the OVEC units, provide the following for each month in 2023:
a. Generation (MWh) on peak and off-peak by month,
b. ICAP (MW),
c. Capacity value ($/MW-day),
d. Energy market revenues ($),
e. Ancillary services revenues ($),
f. Total capacity provided (MW),
g. On and off-peak market prices used to calculate energy market revenues by month.

Response

I&M objects to this request and its subparts on the grounds that they call for an analysis and/or calculation that I&M has not performed and objects to performing. Subject to and without waiving the objections, the Company states the following:

a. I&M it is providing energy supplied to PJM from the OVEC units on an hourly basis for every hour in calendar year 2023 in SC 3-04 CONFIDENTIAL Attachment 1.

b. This data was requested in SC 1-15 and was provided in the Company's response to that question.

c. The capacity OVEC supplies to I&M is used to meet its I&M's capacity obligation under the Fixed Resource Requirement construct in PJM.

d. The Company provided this data on an hourly basis in SC 3-04 CONFIDENTIAL Attachment 1.

e. Please see SC 3-04 Attachment 2 for the requested information.

f. Please see SC 3-04 CONFIDENTIAL Attachment 3 for the requested information.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 3
CASE NO. U-21427

g. This information can be derived from the responses to subparts a and d of this request.

Preparer
Stegall

<u>As to Objections</u>
Counsel

Indiana Michigan Power Company
Ancillary Revenues
I&M Share of Total OVEC

January	$1,772
February	$1,811
March	$2,360
April	$7,713
May	$12,236
June	$14,933
July	$17,945
August	$3,334
September	$3,765
October	$47,059
November	$35,547
December	$8,548
Total 2023	$157,024

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB AND CITIZENS UTILITY BOARD OF MICHIGAN
DATA REQUEST SET NO. 3
CASE NO. U-21427

DATA REQUEST NO. 3-05-SC

Request

Provide the following monthly billed data for 2023 for AEG's share of Rockport.
a. Energy Charge ($),
b. Demand Charge ($),
c. Transmission Charge ($),
d. PJM Expenses/Fees ($),
e. Total Bill ($).

Response

a.-e. Please see the SC3-05 Attachment 1 for the requested information.

Preparer
Welsh

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) **ESTIMATE**
P. O. BOX 60 **01-Mar-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - January, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF January, 2023

	KWH FOR THE MONTH	76,269,312
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	821,532
	Return on Other Capital	419,776
	Total Return	1,241,308
	Fuel	4,048,843
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,158,133
	Depreciation Expense	2,064,368
	Taxes Other Than Federal Income Tax	184,349
	Federal Income Tax	(37,415)
	TOTAL UNIT POWER BILL	8,650,836
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	244,617
	TOTAL PRIOR MONTH'S ADJUSTMENTS	244,617
	TOTAL UNIT POWER BILL	8,895,453

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

4,846,610

DUE DATE - - - February 20, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) — **ESTIMATE**
P. O. BOX 60 — **08-Mar-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - February, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF February, 2023

	KWH FOR THE MONTH	92,974,402
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	760,585
	Return on Other Capital	357,091
	Total Return	1,117,676
	Fuel	3,762,348
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,428,331
	Depreciation Expense	3,402,425
	Taxes Other Than Federal Income Tax	282,445
	Federal Income Tax	(179,498)
	TOTAL UNIT POWER BILL	9,804,976
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	3
	TOTAL PRIOR MONTH'S ADJUSTMENTS	3
	TOTAL UNIT POWER BILL	9,804,980

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,042,632

DUE DATE - - - March 20, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) — **ESTIMATE**
P. O. BOX 60 — **07-Apr-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - March, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF March, 2023
KWH FOR THE MONTH 0

	SUMMARY	TOTAL
Current Month Bill:		
	Return on Common Equity	692,283
	Return on Other Capital	524,082
	Total Return	1,216,365
	Fuel	82,230
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	2,290,432
	Depreciation Expense	3,420,806
	Taxes Other Than Federal Income Tax	292,950
	Federal Income Tax	(199,375)
	TOTAL UNIT POWER BILL	7,094,659
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	(0)
	TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
	TOTAL UNIT POWER BILL	7,094,659

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

7,012,429

DUE DATE - - - April 21, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) — **ESTIMATE**
P. O. BOX 60 — **05-May-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - April, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF April, 2023

	KWH FOR THE MONTH	0
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	654,436
	Return on Other Capital	489,015
	Total Return	1,143,451
	Fuel	(1,282,890)
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,794,973
	Depreciation Expense	3,408,957
	Taxes Other Than Federal Income Tax	299,943
	Federal Income Tax	57,946
	TOTAL UNIT POWER BILL	5,413,631
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	0
	TOTAL PRIOR MONTH'S ADJUSTMENTS	0
	TOTAL UNIT POWER BILL	5,413,631

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,696,521

DUE DATE - - - May 19, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) **ESTIMATE**
P. O. BOX 60 **08-Jun-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - May, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF May, 2023
KWH FOR THE MONTH 0

	SUMMARY	TOTAL
Current Month Bill:		
	Return on Common Equity	621,631
	Return on Other Capital	542,437
	Total Return	1,164,068
	Fuel	48,963
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,677,202
	Depreciation Expense	3,408,944
	Taxes Other Than Federal Income Tax	301,822
	Federal Income Tax	(65,991)
	TOTAL UNIT POWER BILL	6,526,257
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	30,564
	TOTAL PRIOR MONTH'S ADJUSTMENTS	30,564
	TOTAL UNIT POWER BILL	6,556,821

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,507,858

DUE DATE - - - June 20, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) **ESTIMATE**
P. O. BOX 60 **08-Jul-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - June, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF June, 2023

	KWH FOR THE MONTH	175,928,111
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	599,067
	Return on Other Capital	504,092
	Total Return	1,103,159
	Fuel	6,968,384
	Purchased Power	0
	Other Operating Revenues	(8,875)
	Other Operation and Maintenance Exp	1,570,279
	Depreciation Expense	3,409,801
	Taxes Other Than Federal Income Tax	476,595
	Federal Income Tax	(103,505)
	TOTAL UNIT POWER BILL	13,415,839
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	(0)
	TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
	TOTAL UNIT POWER BILL	13,415,838

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,447,454

DUE DATE - - - July 21, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) **ESTIMATE**
P. O. BOX 60 **08-Aug-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - June, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF June, 2023

	KWH FOR THE MONTH	61,127,380
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	617,233
	Return on Other Capital	552,306
	Total Return	1,169,539
	Fuel	2,473,714
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,992,740
	Depreciation Expense	3,435,130
	Taxes Other Than Federal Income Tax	(322,255)
	Federal Income Tax	(102,471)
	TOTAL UNIT POWER BILL	8,637,646
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	0
	TOTAL PRIOR MONTH'S ADJUSTMENTS	0
	TOTAL UNIT POWER BILL	8,637,646

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,163,932

DUE DATE - - - August 19, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) — **ESTIMATE**
P. O. BOX 60 — **09-Sep-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - August, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF August, 2023
KWH FOR THE MONTH 215,394,000

	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	609,231
	Return on Other Capital	534,899
	Total Return	1,144,130
	Fuel	8,403,898
	Purchased Power	0
	Other Operating Revenues	(9,375)
	Other Operation and Maintenance Exp	1,586,767
	Depreciation Expense	3,436,982
	Taxes Other Than Federal Income Tax	260,470
	Federal Income Tax	(40,236)
	TOTAL UNIT POWER BILL	14,782,636
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	(0)
	TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
	TOTAL UNIT POWER BILL	14,782,636

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,378,738

DUE DATE - - - September 22, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) **ESTIMATE**
P. O. BOX 60 **06-Oct-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - September, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF September, 2023
KWH FOR THE MONTH 46,044,780

	SUMMARY	TOTAL
Current Month Bill:		
	Return on Common Equity	619,476
	Return on Other Capital	490,549
	Total Return	1,110,025
	Fuel	1,996,881
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,341,252
	Depreciation Expense	3,434,156
	Taxes Other Than Federal Income Tax	315,565
	Federal Income Tax	1,048,612
	TOTAL UNIT POWER BILL	9,237,742
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	(0)
	TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
	TOTAL UNIT POWER BILL	9,237,742

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

7,240,861

DUE DATE - - - October 19, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) — **ESTIMATE**
P. O. BOX 60 — **07-Nov-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - October, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF October, 2023
KWH FOR THE MONTH 1,249,920

	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	638,173
	Return on Other Capital	515,762
	Total Return	1,153,935
	Fuel	281,294
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	813,898
	Depreciation Expense	3,375,552
	Taxes Other Than Federal Income Tax	368,169
	Federal Income Tax	61,481
	TOTAL UNIT POWER BILL	6,045,579
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	(0)
	TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
	TOTAL UNIT POWER BILL	6,045,579

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

5,764,285

DUE DATE - - - November 19, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) **ESTIMATE**
P. O. BOX 60 **08-Dec-23**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - November, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF November, 2023

	KWH FOR THE MONTH	35,330,420
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	612,584
	Return on Other Capital	458,128
	Total Return	1,070,712
	Fuel	1,390,998
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,747,000
	Depreciation Expense	3,424,237
	Taxes Other Than Federal Income Tax	198,894
	Federal Income Tax	2,184,215
	TOTAL UNIT POWER BILL	10,007,305
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	18,626
	TOTAL PRIOR MONTH'S ADJUSTMENTS	18,626
	TOTAL UNIT POWER BILL	10,025,932

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

8,634,934

DUE DATE - - - December 21, 2023

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-2639

INDIANA MICHIGAN POWER COMPANY (BU132) — **ESTIMATE**
P. O. BOX 60 — **02-Feb-24**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - December, 2023

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF December, 2023

	KWH FOR THE MONTH	0
	SUMMARY	**TOTAL**
Current Month Bill:		
	Return on Common Equity	607,554
	Return on Other Capital	468,063
	Total Return	1,075,617
	Fuel	215,547
	Purchased Power	0
	Other Operating Revenues	(8,750)
	Other Operation and Maintenance Exp	1,017,788
	Depreciation Expense	3,438,997
	Taxes Other Than Federal Income Tax	315,000
	Federal Income Tax	(91,488)
	TOTAL UNIT POWER BILL	5,962,710
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	550,656
	TOTAL PRIOR MONTH'S ADJUSTMENTS	550,656
	TOTAL UNIT POWER BILL	6,513,366

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

6,297,819

DUE DATE - - - January 19, 2024

ANNUAL REPORT — 2022

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 Energy Harbor Corp. 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
Energy Harbor Corp	4.85
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
	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

Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), faced a new challenge in 2022 -- record energy demand. The rising price of natural gas and continued pressures from reduced baseload generation in the region resulted in increased demand for power and rising prices. The employees of OVEC-IKEC were up to the challenge and generated over 11 million megawatts of power. Coal supply was strained due to the increase demand for coal generation and was the primary cause of the OVEC-IKEC units not producing even more power to meet the increased demand.

For 2023, we have seen demand for power in the PJM market fall due to oversupply of natural gas and reduced prices. This oversupply was caused by milder than expected winter weather. Given the increase in demand last year and the need for critical generation to support the grid, as we saw in late December of 2022 with multiple blackouts in parts of the country, the OVEC-IKEC team has focused on preparing our units for the next market shift or future grid event. OVEC-IKEC continues to strive to bring value to our Sponsors and believes that our units will be even more critical with the continued retirement of baseload facilities across the country, which reduces the amount of reliable power available to meet load demand and to support the grid.

No matter what challenges the OVEC-IKEC team faces, we continue 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.

SAFETY

System Office employees, including Electrical Operations, completed eight years in April with no recordable injuries; and on May 11, they also reached a milestone of 17 years without a lost-time injury.

Through June 2023, five recordable injuries have occurred companywide, three at Clifty Creek Plant and two at Kyger Creek Plant. Four of the five recordable injuries are DART cases.

In alignment with OVEC's 2023 Strategic Plan Zero Harm and Continuous Improvement Objectives, emphasis on the objectives of Leadership in the Field and Integrating Strategic Partners into the OVEC-IKEC Safety Culture continues. Initiatives for Leaders include focusing on effective and quality coaching in the field by attending pre-job briefings and conducting team field observations.

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 2023, 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 2022, the combined equivalent availability of the five generating units at Kyger Creek and the six units at Clifty Creek was 66.3 percent compared with 70.8 percent in 2021. The combined equivalent forced outage rate (EFOR) at both plants was 11.0 percent in 2022 compared with 6.6 percent in 2021.

Through May 2023, the combined EFOR of the eleven generating units was 8.3 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 90.5 percent in 2022 compared with 76.6 percent in 2021. The on-peak use factor averaged 92.6 percent in 2022 compared with 81.8 percent in 2021. The off-peak use factor averaged 87.7 percent in 2022 and 69.9 percent in 2021.

In 2022, OVEC delivered 11.0 million megawatt hours (MWh) to the Sponsoring Companies under the terms of the Inter-Company Power Agreement compared with 10.0 million MWh delivered in 2021. The increases to both generation and utilization were due to the impact of a record high energy demand combined with high natural gas prices and reduced baseload generation in the region.

POWER COSTS

In 2022, OVEC's average power cost to the Sponsoring Companies was $69.21 per MWh compared with $65.82 per MWh in 2021. Despite the increase in generation from 2021 to 2022, strains on coal supply increased fuel cost and led to less production than anticipated for 2022. As a result, the average power cost increased for 2022.

2022 ENERGY SALES OUTLOOK

Weakened demand from the oversupply of natural gas and lower prices has impacted OVEC's generation in 2023. OVEC's use factor through May was 71.2% compared to 90.6% through May 2022. OVEC's updated projection for 2023, which assumes some continued weaker than expected energy demand through the end of the year, is projected at approximately 10 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). Since 2013, CIP has obtained over $26.7 million in sustainable savings through implementation of more than 9,800 process improvements. 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 2022, 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 also engaged 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 expected to be realized beginning in 2023.

ENVIRONMENTAL COMPLIANCE

OVEC-IKEC continues to maintain a strong commitment to meeting all applicable federal, state and local environmental rules and regulations. During 2022, 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 sixth consecutive year, OVEC successfully met the challenge of operating in compliance with the more stringent ozone season NO_x constraints that initially went into effect with the 2017 ozone season with the adoption of EPA's CSAPR Update Rule. The Company is well positioned to continue to operate all SCR controlled units during 2023.

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 is also pursuing a marketing agreement for its dry fly ash following the completion of the dry fly ash conversion project at the plant.

2022 saw heavy construction activities at both plant facilities as the Company executed its CCR Rule Part A compliance strategy. The CCR Part A Rule requires sources to stop placing ash and non-ash transport wastewaters into all clay-lined and unlined surface impoundments receiving CCR material. The Company is on track to complete these activities in the third quarter of 2023, and then initiate closure of these impoundments consistent with the CCR rule requirements.

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 applicable to certain wastewater discharges from Clifty Creek and Kyger Creek operations. The Company expects to meet the applicability dates for each of the specific 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 for any new coal or gas plants as well as for existing coal and gas plants. As drafted, the rule includes multiple dates and options for existing fossil generation to demonstrate compliance. USEPA expects to finalize this rule by 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 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 December 15, 2022, Mr. Aaron D. Walker, President and Chief Operating Officer, Appalachian Power, was elected a director of the OVEC Board and appointed a member of the Human Resources Committee, effective January 1, 2023, with the resignation of Mr. Christian Beam. Mr. Beam had served on the OVEC Board since 2018.

On December 15, 2022, Mr. Phillip R. Ulrich, Executive Vice President and Chief Human Resources Officer, American Electric Power, was elected a director of the OVEC Board and appointed Chairman of the Human Resources Committee, effective January 1, 2023, with the resignation of Ms. Julie Sloat. Ms. Sloat had served on the OVEC Board since 2016.

On December 15, 2022, Mr. Steven Baker, President and Chief Operating Officer, Indiana Michigan Power, was elected a member of the IKEC Board effective January 1, 2023, with the resignation of Mr. Toby Thomas. Mr. Thomas had served on the IKEC Board since 2017.

On May 5, 2023, Mr. Wayne D. Games, CenterPoint Energy, resigned as a director of OVEC and IKEC. Mr. Games had served on the OVEC Board since 2014 and the IKEC Board since 2011.

Paul Chodak III
OVEC-IKEC President

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2022 AND 2021

	2022	2021
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 2,951,082,964	$ 2,892,814,447
Less—accumulated provisions for depreciation	1,899,379,433	1,766,903,520
	1,051,703,531	1,125,910,927
Construction in progress	99,942,979	56,005,177
Total electric plant	1,151,646,510	1,181,916,104
CURRENT ASSETS:		
Cash and cash equivalents	50,612,220	56,366,876
Accounts receivable	50,711,358	36,289,466
Fuel in storage	62,374,566	40,352,672
Emission allowances	-	81,833
Materials and supplies	46,784,231	43,646,500
Property taxes applicable to future years	3,162,000	3,116,700
Other regulatory assets	1,644,000	-
Prepaid expenses and other	6,394,911	4,430,506
Total current assets	221,683,286	184,284,553
REGULATORY ASSETS:		
Unrecognized postemployment benefits	10,567,071	8,611,705
Unrecognized pension benefits	9,210,770	18,796,585
Income taxes billable to customers	12,938,237	13,045,853
Other regulatory assets	6,058,187	9,262,500
Total regulatory assets	38,774,265	49,716,643
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	406,653	755,213
Long-term investments	277,080,718	301,302,862
Postretirement benefits	29,096,447	11,877,835
Other	2,866,535	2,866,534
Total deferred charges and other	309,450,353	316,802,444
TOTAL	$ 1,721,554,414	$ 1,732,719,744

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2022 AND 2021

	2022	2021
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2022 and 2021	$ 10,000,000	$ 10,000,000
Long-term debt	911,772,190	979,998,445
Line of credit borrowings	110,000,000	10,000,000
Retained earnings	25,501,978	22,800,986
Total capitalization	1,057,274,168	1,022,799,431
CURRENT LIABILITIES:		
Current portion of long-term debt	69,523,395	132,134,224
Accounts payable	85,520,164	49,515,658
Accrued other taxes	10,925,537	11,116,929
Regulatory liabilities	72,118,927	58,034,516
Accrued interest and other	21,852,765	22,342,003
Total current liabilities	259,940,788	273,143,330
COMMITMENTS AND CONTINGENCIES (Notes 3, 9, 11, and 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	115,060,018	91,142,107
Advance billing of debt reserve	120,000,000	120,000,000
Total regulatory liabilities	235,060,018	211,142,107
OTHER LIABILITIES:		
Pension liability	9,210,770	18,796,585
Deferred income tax liability	15,267,530	21,704,751
Asset retirement obligations	131,942,458	159,573,299
Postretirement benefits obligation	528,669	5,379,460
Postemployment benefits obligation	10,567,071	8,611,705
Parent advances	-	-
Other non-current liabilities	1,762,942	11,569,076
Total other liabilities	169,279,440	225,634,876
TOTAL	$ 1,721,554,414	$ 1,732,719,744

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, 2022 AND 2021

	2022	2021
REVENUES FROM CONTRACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 9,068,557	$ 5,221,889
Sponsoring Companies	752,430,431	616,419,611
Other	-	1,783,416
Total revenues from contracts with customers	761,498,988	623,424,916
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	354,335,638	260,173,759
Purchased power	10,853,154	4,963,205
Other operation	85,527,745	85,531,745
Maintenance	87,282,316	79,212,668
Depreciation	152,943,176	117,385,278
Taxes—other than income taxes	12,077,825	12,292,661
Total operating expenses	703,019,854	559,559,316
OPERATING INCOME	58,479,134	63,865,600
OTHER INCOME (EXPENSE)	(28,436)	(27,487)
INCOME BEFORE INTEREST CHARGES	58,450,698	63,838,113
INTEREST CHARGES:		
Amortization of debt expense	3,704,984	4,439,333
Interest expense	52,044,722	56,702,100
Total interest charges	55,749,706	61,141,433
NET INCOME	2,700,992	2,696,680
RETAINED EARNINGS—Beginning of year	22,800,986	20,104,306
RETAINED EARNINGS—End of year	$ 25,501,978	$ 22,800,986

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
AS OF DECEMBER 31, 2022 AND 2021

	2022	2021
OPERATING ACTIVITIES:		
Net income	$ 2,700,992	$ 2,696,680
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	152,943,176	117,385,278
Amortization of debt expense	3,704,984	4,439,333
Changes in assets and liabilities:		
Accounts receivable	(14,421,892)	8,611,082
Fuel in storage	(22,021,893)	38,975,980
Materials and supplies	(3,137,732)	(3,218,237)
Property taxes applicable to future years	(45,300)	138,300
Emissions allowances	81,833	62,072
Prepaid expenses and other	(1,964,405)	(398,939)
Other regulatory assets	(4,837,520)	14,209,564
Other noncurrent assets	(12,937,493)	(12,390,783)
Accounts payable	38,396,151	10,467,693
Accrued taxes	(6,520,997)	(131,060)
Accrued interest and other	404,812	(3,324,951)
Other liabilities	(64,451,051)	(25,617,393)
Other regulatory liabilities	44,820,112	68,751,241
Net cash provided by operating activities	112,713,777	220,655,860
INVESTING ACTIVITIES:		
Electric plant additions	(88,297,756)	(44,970,990)
Proceeds from sale of long-term investments	807,332,153	47,043,450
Purchases of long-term investments	(802,319,245)	(68,821,414)
Net cash (used in) provided by investing activities	(83,284,848)	(66,748,954)
FINANCING ACTIVITIES:		
Changes in short-term intercompany borrowings	-	-
Debt issuance and maintenance costs	(2,103,018)	(2,511,973)
Repayment of Senior 2006 Notes	(26,176,986)	(24,713,983)
Repayment of Senior 2007 Notes	(18,650,218)	(17,590,534)
Repayment of Senior 2008 Notes	(20,640,593)	(19,345,070)
Repayment of Senior 2017A Notes	(66,666,667)	(33,333,333)
Proceeds from line of credit	100,000,000	-
Payments on line of credit	-	(50,000,000)
Principal payments under finance leases	(946,103)	(880,196)
Net cash (used in) provided by financing activities	(35,183,585)	(148,375,089)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,754,656)	5,531,817
CASH AND CASH EQUIVALENTS—Beginning of year	56,366,876	50,835,059
CASH AND CASH EQUIVALENTS—End of year	$ 50,612,220	$ 56,366,876
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 51,172,106	$ 57,401,894
Income taxes (received) paid—net	$ 8,100,000	$ -
Non-cash electric plant additions included in accounts payable at December 31	$ 903,177	$ 3,242,769

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, 2022 AND 2021

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 23% 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, 2022, 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 power sales 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, 2022 AND 2021

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2022 and 2021, were as follows:

	2022	2021
Regulatory assets:		
Current regulatory assets:		
Other regulatory assets	$ 1,644,000	$ -
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	10,567,071	8,611,705
Unrecognized pension benefits	9,210,770	18,796,585
Income taxes billable to customers	12,938,237	13,045,853
Other regulatory assets	6,058,187	9,262,500
Total	38,774,265	49,716,643
Total regulatory assets	$ 40,418,265	$ 49,716,643
Regulatory liabilities:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ 70,190,903	$ 56,525,728
Deferred credit—advance collection of interest	1,928,024	1,508,788
Total	72,118,927	58,034,516
Noncurrent regulatory liabilities:		
Postretirement benefits	115,060,018	91,142,107
Advance billing of debt reserve	120,000,000	120,000,000
Total	235,060,018	211,142,107
Total regulatory liabilities	$307,178,945	$269,176,623

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, 2022, consist primarily of interest expense collected from customers in advance of expense recognition and customer billings for construction in progress. These amounts will be credited to customer bills during 2023. Other regulatory liabilities consist primarily of postretirement benefit costs and advanced billings collected from the Sponsoring Companies for debt service.

The regulatory liability for postretirement benefits recorded at December 31, 2022 and 2021, represents amounts collected in historical billings in excess of the accounting principles generally accepted in the United States of America (GAAP) net periodic benefit costs, including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental unfunded plan obligations 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, as well as emission allowances, for use in the generation of electricity for regulatory compliance purposes due to the generation of electricity. 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 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 the provisions of the accounting guidance for Investments—Debt and Equity Securities. 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 most investment securities is determined by reference to currently available market prices. 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 2022 and 2021 on securities still held at the balance sheet date were $(14,659,333.89) and $5,434,007, respectively.

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 being 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.

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 the obligations are incurred and 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 any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs, including the impacts of the coal combustion residuals rule.

Balance—January 1, 2021	$ 138,933,456
Accretion	6,281,878
Liabilities settled	(10,026,043)
Revisions to cash flows	24,384,008
Balance—December 31, 2021	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

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, 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 appropriate 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 2022 and 2021 reflect the outcome of the decommission and demolition study resulting in an upward revision of $4.5 million and $24.4 million. This increase was primarily driven by future groundwater monitoring requirements.

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 disclosure of 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 three contracts with customers resulting in three types of revenue. These three contracted revenue types are:

1) Sales of Electric Energy to Department of Energy
2) Sales of Electric Energy to Sponsoring Companies
3) Sales of Electric Energy to Pennsylvania, Jersey, Maryland Power Pool (PJM)

The performance obligations and recognition of revenue are similar and both individually and, in the aggregate, were not materially impacted by the implementation of Topic 606. The Companies have no contract assets or liabilities as of December 31, 2022. The following table provides information about the Companies' receivables from contracts with customers:

	Accounts Receivable
Beginning balance—January 1, 2021	$ 44,900,548
Ending balance—December 31, 2021	36,289,466
Increase/(decrease)	$ (8,611,082)
Beginning balance—January 1, 2022	$ 36,289,466
Ending balance—December 31, 2022	50,711,358
Increase/(decrease)	$ 14,421,892

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through May 16, 2023, which is the date the consolidated financial statements were issued.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2022 and 2021 included the sale of all generated power to them, the purchase of arranged power from them, and other utility systems in order to meet the DOE's power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with 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; and 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, 2022 and 2021, balances due from the Sponsoring Companies are as follows:

	2022	2021
Accounts receivable	$ 42,765,234	$ 30,117,445

During 2022 and 2021, American Electric Power accounted for approximately 44% of operating revenues from Sponsoring Companies and Buckeye Power accounted for 18%. No other Sponsoring Company accounted for more than 10%.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2022. 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:

	2022	2021
General services	$3,039,684	$3,037,297
Specific projects	539,361	1,072,053
Total	$3,579,045	$4,109,350

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 2023 through 2025. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2023 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, 2022, are included in the table below:

2023	$363,235,494
2024	335,977,000
2025	174,879,000

4. ELECTRIC PLANT

Electric plant at December 31, 2022 and 2021, consists of the following:

	2022	2021
Steam production plant	$2,855,417,793	$2,797,653,316
Transmission plant	82,481,029	82,008,817
General plant	13,157,578	13,125,750
Intangible	26,564	26,564
	2,951,082,964	2,892,814,447
Less accumulated depreciation	1,899,379,433	1,766,903,520
	1,051,703,531	1,125,910,927
Construction in progress	99,942,979	56,005,177
Total electric plant	$1,151,646,510	$1,181,916,104

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 being depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC has a revolving credit facility of $185 million set to expire on February 26, 2024. At December 31, 2022 and 2021, OVEC had borrowed $110 million and $10 million, respectively, under the revolving credit facility. Interest expense related to lines of credit borrowings was $1,952,656 in 2022 and $481,649 in 2021. During 2022 and 2021, OVEC incurred annual commitment fees of $393,861 and $317,285, respectively, based on the borrowing limits of the line of credit.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2022 and 2021:

	Interest Rate Type	Interest Rate	2022	2021
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 98,493,793	$ 123,200,015
2006B due June 15, 2040	Fixed	6.40	49,995,256	51,465,748
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	41,630,472	53,268,981
2007A-B due February 15, 2026	Fixed	5.90	10,484,226	13,415,270
2007A-C due February 15, 2026	Fixed	5.90	10,567,708	13,522,091
2007B-A due June 15, 2040	Fixed	6.50	24,904,952	25,652,971
2007B-B due June 15, 2040	Fixed	6.50	6,272,067	6,460,448
2007B-C due June 15, 2040	Fixed	6.50	6,322,007	6,511,889
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	12,999,705	16,632,689
2008B due February 15, 2026	Fixed	6.71	26,166,048	33,681,096
2008C due February 15, 2026	Fixed	6.71	28,529,215	35,938,542
2008D due June 15, 2040	Fixed	6.91	36,488,446	37,521,292
2008E due June 15, 2040	Fixed	6.91	37,122,454	38,173,246
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 June 1, 2032	Fixed	4.75	76,800,000	76,800,000
2012A due June 1, 2039	Fixed	4.75	123,200,000	123,200,000
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 2017 Notes—				
2017A due August 4, 2022	Floating	4.07	-	66,666,667
Series 2019 Bonds—				
2019A due September 1, 2029	Fixed	3.25	100,000,000	100,000,000
Total debt			989,976,349	1,122,110,945
Total premiums and discounts—net			-	(392,666)
Less unamortized debt expense			(8,680,764)	(9,585,610)
Total debt net of premiums, discounts, and unamortized debt expense			981,295,585	1,112,132,669
Current portion of long-term debt			69,523,395	132,134,224
Total long-term debt			$911,772,190	$ 979,998,445

Since 2009, OVEC has entered a number of tax-exempt financing arrangements. Under these arrangements, the Ohio Air Quality Development Authority (the "OAQDA"), and the Indiana Finance Authority (the "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, among other payments.

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 $36 million as of December 31, 2022.

The annual maturities of long-term debt as of December 31, 2022, are as follows:

2023	$ 69,523,395
2024	73,831,592
2025	78,243,501
2026	129,341,140
2027	6,492,120
2028–2040	632,544,601
Total	$ 989,976,349

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

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:

	2022	2021
Income tax expense at statutory rate (21%)	$ 567,208	$ 566,303
Temporary differences flowed through to customer bills	(568,333)	(579,754)
Permanent differences and other	1,125	13,451
Income tax provision	$ -	$ -

Components of the income tax provision were as follows:

	2022	2021
Current income tax expense—federal	$ 6,330,131	$ -
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	(6,330,131)	-
Total income tax provision	$ -	$ -

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 $12,938,237 and $13,045,856 at December 31, 2022 and 2021, respectively.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

Deferred income tax assets (liabilities) at December 31, 2022 and 2021, consisted of the following:

	2022	2021
Deferred tax assets:		
Deferred revenue—advances for construction	$ 14,741,991	$ 13,194,899
Federal net operating loss carryforwards	-	5,086,419
Pension liability	905,379	3,129,540
Postemployment benefit obligation	2,219,371	1,809,185
Asset retirement obligations	27,711,492	33,523,862
Advanced collection of interest and debt service	23,990,521	25,527,102
Miscellaneous accruals	1,087,987	1,174,133
Regulatory liability-postretirement benefits	24,165,722	20,185,875
Total deferred tax assets	94,822,463	103,631,015
Deferred tax liabilities:		
Prepaid expenses	(644,205)	(590,692)
Electric plant	(69,476,217)	(83,922,216)
Unrealized gain/loss on marketable securities	(1,542,690)	(5,324,468)
Postretirement benefit obligation	(6,000,007)	(699,371)
Regulatory asset—pension benefits	(1,934,511)	(3,948,869)
Regulatory asset—asset retirement costs	-	(47,360)
Regulatory asset—unrecognized postemployment benefits	(2,219,371)	(1,809,185)
Regulatory asset—income taxes billable to customers	(2,711,388)	(2,732,737)
Total deferred tax liabilities	(84,528,389)	(99,074,898)
Valuation allowance	(25,561,604)	(26,260,868)
Deferred income tax liability	$(15,267,530)	$ (21,704,751)

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 their deferred tax assets as of December 31, 2022 and 2021.

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, 2022 and 2021, 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 2017 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2016 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2016 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 of their 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 54% and 46% split between OVEC and IKEC, respectively, as of December 31, 2022, and December 31, 2021. The allocated amounts for postretirement medical plan represent approximately a 52% and 48% split between OVEC and IKEC, respectively, as of December 31, 2022, and 53% and 47% split between OVEC and IKEC, respectively, as of December 31, 2021.

The Pension Plan's assets as of December 31, 2022, 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 all 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.

Equity investment limitations:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of each investment manager's equity portfolio.
- Individual securities must be less than 15% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

Fixed-Income Limitations—As of December 31, 2022, 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.

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, 2022 and 2021, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2022	2021	2022	2021
Change in benefit obligation:				
Benefit obligation—beginning of year	$263,593,975	$276,434,312	$165,904,272	$178,235,236
Service cost	6,243,823	7,721,082	3,704,556	4,100,166
Interest cost	8,424,852	7,705,582	4,896,183	4,591,069
Plan participants' contributions	-	-	1,409,028	1,355,555
Benefits paid	(7,615,660)	(16,830,398)	(6,685,855)	(5,542,477)
Net actuarial loss (gain)	(73,927,665)	(11,372,798)	(54,000,158)	(16,835,277)
Expenses paid from assets	(65,543)	(63,805)	-	-
Settlements	(21,137,991)	-	-	-
Benefit obligation—end of year	175,515,791	263,593,975	115,228,026	165,904,272
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	244,797,390	241,649,624	172,402,647	166,240,130
Actual return on plan assets	(55,873,175)	9,041,969	(23,353,088)	10,326,206
Expenses paid from assets	(65,543)	(63,805)	-	-
Employer contributions	6,200,000	11,000,000	23,072	23,233
Plan participants' contributions	-	-	1,409,028	1,355,555
Benefits paid	(7,615,660)	(16,830,398)	(6,685,855)	(5,542,477)
Settlements	(21,137,991)	-	-	-
Fair value of plan assets—end of year	166,305,021	244,797,390	143,795,804	172,402,647
(Underfunded) Overfunded status—end of year	$ (9,210,770)	$ (18,796,585)	$ 28,567,778	$ 6,498,375

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan.

The accumulated benefit obligation for the Pension Plan was $159,689,081 and $236,107,876 at December 31, 2022 and 2021, respectively.

During 2022, the Plans paid lump sum payouts to retirees of $21.1 million that triggered settlement accounting in the third quarter. Settlement accounting resulted in the accelerated recognition of $3.0 million of net periodic pension cost in 2022.

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 generally accepted accounting principles, 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	
	2022	2021	2022	2021
Service cost	$ 6,243,823	$ 7,721,082	$ 3,704,556	$ 4,100,166
Interest cost	8,424,852	7,705,582	4,896,183	4,591,069
Expected return on plan assets	(12,284,250)	(12,520,433)	(7,716,682)	(7,440,275)
Amortization of prior service cost	(416,566)	(416,565)	(2,781,539)	(2,781,539)
Recognized actuarial loss (gain)	707,787	1,226,576	(2,049,032)	(1,414,607)
Settlement	2,998,906	-	-	-
Total benefit cost	$ 5,674,552	$ 3,716,242	$(3,946,514)	$(2,945,186)
Pension and other postretirement benefits expense recognized in the consolidating statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 5,200,000	$ 6,000,000	$ -	$ -

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2022 and 2021:

	Fair Value Measurements at Reporting Date Using			
2022	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (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
2021	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 10,845,681	$ -	$ -	$ 10,845,681
Equity mutual funds	47,445,588	-	-	47,445,588
Index futures	-	460	-	460
Fixed-income securities	-	164,505,732	-	164,505,732
Commodities	-	43	-	43
Cash equivalents	6,425,767	-	-	6,425,767
Subtotal benefit plan assets	$ 64,717,036	$ 164,506,235	$ -	229,223,271
Investments measured at net asset value (NAV)				15,574,119
Total benefit plan assets				$ 244,797,390

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2022 and 2021:

	Fair Value Measurements at Reporting Date Using			
2022	**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	$ 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
2021				
Equity mutual funds	$ 55,045,316	$ -	$ -	$ 55,045,316
Equity exchange traded funds	4,212,480	-	-	4,212,480
Fixed-income mutual funds	86,580,043	-	-	86,580,043
Fixed-income securities	-	19,461,407	-	19,461,407
Cash equivalents	1,229,124	-	-	1,229,124
Benefit plan assets	$ 147,066,963	$ 19,461,407	$ -	166,528,370
Uncleared cash disbursements from benefits paid				(4,163,688)
Investments measured at net asset value (NAV)				10,037,965
Total benefit plan assets				$ 172,402,647

Investments that were measured at net asset value (NAV) 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.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2022 and 2021, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2022	2021	2022		2021	
			Medical	Life	Medical	Life
Discount rate	5.61 %	3.08 %	5.57 %	5.57 %	3.06 %	3.06 %
Rate of compensation increase for next year	4.50	3.00	N/A	4.50	N/A	3.00
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	2022	N/A	2026	N/A	2022

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021, were as follows:

	Pension Plan		
	For the Period October 1 through December 31, 2022	For the Period January 1 through September 30, 2022	For the Period January 1 through December 31, 2021
Discount rate	5.65 %	3.08 %	2.85 %
Expected long-term return on plan assets	7.00	5.25	5.25
Rate of compensation increase	3.00	3.00	3.00

	2022	2021
Rate of compensation increase for next year	4.50 %	3.00 %
Rate to which compensation is assumed to decline (ultimate trend rate)	3.00	3.00
Year that rate reaches the ultimate trend	2026	2022

	Other Postretirement Obligations			
	2022		2021	
	Medical	Life	Medical	Life
Discount rate	3.06 %	3.06 %	2.82 %	2.82 %
Expected long-term return on plan assets	4.47	5.00	4.47	5.00
Rate of compensation increase	N/A	3.00	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.

Assumed health care cost trend rates at December 31, 2022 and 2021, were as follows:

	2022	2021
Health care trend rate assumed for next year—participants under 65	7.00 %	6.50 %
Health care trend rate assumed for next year—participants over 65	7.00	7.10
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	2027

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2022 and 2021, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2022	2021	2022	2021
Asset category:				
Equity securities	30 %	31 %	39 %	40 %
Debt securities	70	69	61	60

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,700,000 to their Pension Plan and $23,000 to their Other Postretirement Benefits plan in 2023.

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
2023	$ 9,784,295	$ 6,782,857
2024	10,521,802	7,433,153
2025	10,712,421	8,006,014
2026	11,092,162	8,505,315
2027	11,419,496	8,957,956
Five years thereafter	62,464,354	48,511,622

Postemployment Benefits—The Companies follow the accounting guidance in FASB ASC 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 statements. The allocated amounts represent approximately a 31% and 69% split between OVEC and IKEC, respectively, as of December 31, 2022, and approximately a 43% and 57% split between OVEC and IKEC, respectively, as of December 31, 2021. 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 $10,567,071 and $8,611,705 at December 31, 2022 and 2021, 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 2022 and 2021 were $1,948,147 and $1,914,558, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations

On March 10, 2005, the United States Environmental Protection Agency (the 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, and 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 MATS rule has also undergone legal challenges since it went into effect, and there are a few remaining legal issues pending. The controls the Companies have installed have proven to be adequate to meet the stringent emissions requirements outlined in the MATS rule.

After CAIR was promulgated, legal challenges resulted in that rule being remanded back to the USEPA. The USEPA subsequently promulgated a replacement rule to CAIR called the Cross-State Air Pollution Rule (CSAPR). CSAPR was issued on July 6, 2011, and it was scheduled to go into effect on January 1, 2012. However, a legal challenge of that rule resulted in a stay. The stay was lifted by the D.C. Circuit Court in 2014 and CSAPR, which requires significant NO_x and SO_2 emissions reductions, became effective on January 1, 2015. Further legal challenges of CSAPR resulted in the U.S. Supreme Court remanding portions of the CSAPR rule back to the D.C. Circuit Court for additional review and subsequent action by the USEPA. This resulted in the USEPA issuing the CSAPR Update rule which became final on September 7, 2016, and went into effect beginning with the May 1, 2017 to September 30, 2017 ozone season. The CSAPR Update did not replace CSAPR, it only required additional reductions in NO_x emissions from utilities in 22 states (including Ohio and Indiana) during the ozone season. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update rule requirements in the 2017 ozone season. That strategy was standardized to meet future ozone season compliance obligations, and its execution provided for another successful ozone season in 2019. The CSAPR Update Rule has also been subject to extensive litigation, and the D.C. Circuit Court of Appeals issued a decision on September 13, 2019, on one of those legal challenges that 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 Administer Regan signed a final rule revising the CSAPR Update Rule to ensure states fully comply with their “good neighbor” obligations to comply with the 2008 Ozone NAAQS standard. This revised rule went into effect on June 29, 2021, and it 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 our near-term compliance strategy, nor is it expected to materially change future operations.

On February 28, 2022, the USEPA proposed federal implementation rule known as the proposed “Transport Rule.” This proposed new draft rule is 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, and the new rule will go into effect during the 2023 ozone season, May 1, 2023 through September 30, 2023. The final rule terms are being evaluated for longer term impacts; however, the rule is not expected to materially impact the Companies near term compliance strategy.

As a result of the installation and effective operation of the FGD systems and the SCR systems at each plant, management did not need to purchase additional annual SO_2 allowances, annual NO_x allowances or ozone season NO_x allowances as part of the ozone season CSAPR Update Rule that went into effect in 2021 to cover actual emissions. The Companies also maintain a bank of allowances for all three programs as a hedge to cover future emissions in the event of any short-term operating events or other external factors. Depending on a variety of operational and economic factors, management may elect to consume a portion of these banked allowances and/or strategically purchase additional CSAPR annual and ozone season allowances in 2023 and beyond for compliance with the CSAPR rule and the new Transport Rule implements the 2015 ozone NAAQS beginning with the 2023 ozone season.

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 is less likely in the short term as well; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons and are continuing to evaluate the need for additional NO_x controls or ongoing changes in dispatch criteria for that unit during the ozone season as a result of the USEPA's new ozone season Transport Rule that will go into effect during the 2023 NO_x ozone season.

CCR Rule

In 2010, the USEPA published a proposed rule to regulate the disposal and beneficial reuse of coal combustion residuals (CCRs), including fly ash and boiler slag generated at coal-fired electric generating units as well as FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials, and another would allow states to retain primary authority to regulate the beneficial reuse and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the USEPA issued a prepublication copy of its final rule in December 2014. The rule was published in the Federal Register in April 2015 and became effective in October 2015.

In the final rule, the USEPA elected to regulate CCR as a nonhazardous solid waste and issued new minimum federal solid waste management standards. 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, notice, and Internet posting requirements.

The Companies have been systematically implementing the applicable provisions of the CCR rule. The Companies have completed all compliance obligations associated with the rule to date 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 at Clifty Creek, and landfill runoff collection pond at Clifty Creek will have on local groundwater quality. To date, these four CCR units 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 facility to determine if there are alternative sources that are influencing groundwater quality and to evaluate the extent of the groundwater quality impact. Concurrently, a facility must continue to evaluate groundwater quality 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 from sources other than the CCR unit. 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 (QPE) to determine what corrective actions were feasible for each CCR unit, and then held a public meeting to discuss these options with the public 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 WIIN Act) 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; 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 and 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. The USEPA's determination is preliminary and is not a final action. The preliminary determination was also subject to a public notice and comment, that ended March 25, 2022. Upon conclusion of the public notice and comment period, and subsequent review of comments filed, the USEPA had the option to take a final agency action to either approve or deny IKEC's alternative closure dates. However, the USEPA has taken 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, but has yet to receive any determination from the USEPA. The Companies have continued to execute their CCR Rule Part A compliance strategy throughout 2022. Completion of that work is anticipated to be completed in mid-2023. At that time, the Companies anticipate withdrawing their applications to the USEPA.

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.

In February 2014, the USEPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the USEPA supports these beneficial uses. Currently, approximately 65 percent of the coal ash and other residual products from the Companies' generating facilities are reused in the production of cement and wallboard, as soil amendments, as abrasives or road treatment materials, and for other beneficial uses.

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 replaced the previously existing 24-hour and annual standards and 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 SO2 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 settle agreement with Sierra Club/NRDC 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 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, Ohio EPA 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. The Companies are still optimistic the USEPA will eventually do so as there are now five 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 $\mu g/m^3$ to within the range of 9.0 to 10.0 $\mu g/m^3$. The Companies will continue to monitor that rulemaking effort to determine what impact a revision to this NAAQS standard could have on unit operations. A final determination of revising this NAAQS standard is not expected before 2024.

Steam Electric ELGs

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 the Companies to modify the way they handle a number of wastewater processes at both power plants. 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; and then 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 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. The USEPA stay on portions of the ELG rule does not impact the need to convert Kyger Creek station to dry fly ash handling or the associated timeline. The Clifty Creek station already has a dry fly ash handling system in place, so this provision of the rule will not impact Clifty Creek's operations. Construction activities associated with dry fly ash conversion at Kyger Creek were completed in late 2022.

2. The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. For Clifty Creek and Kyger Creek, this will result in the conversion of each plant's boiler slag pond to a closed-loop sluicing system for

boiler slag, with up to a ten percent purge based on the volume of each facilities' total wetted volume. The Companies conducted a Phase I engineering study in 2016 to determine options and costs associated with retrofitting the plants' boiler slag treatment systems but postponed the study until more information was available from the USEPA on the technologies being considered in the revised rule. After reviewing the new rule in draft, the Companies resumed the engineering study needed to formulate an overall compliance strategy based on this updated information. This study includes a further evaluation of technologies or retrofits capable of complying with the requirements of the revised rule, which included preliminary engineering, design, and schedule development that were initiated late in 2019. The Companies have completed the required evaluation associated with each facilities' boiler slag/bottom ash transport wastewater treatment in 2020. This feed information was used to develop design and to initiate the bid process to conduct the work. Both the Kyger Creek and Clifty Creek Stations have secured various environmental permits necessary to commence construction on the boiler slag/bottom ash handling systems. Work associated with the Companies' CCR and ELG compliance strategies commenced in 2021. Kyger Creek's system was placed into service in early 2023 and Clifty Creek's system is expected to be placed into service in the second quarter of 2023.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges. Specifically, there were to be new internal limits for arsenic, mercury, selenium, and nitrate/nitrite nitrogen from the FGD chlorides purge stream wastewater treatment plant at each plant. 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 waste water 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 were 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 most significant change to the rule is associated with the final effluent limitation for mercury, which was ultimately lower than the final limit in the 2015 version of the rule, resulting in the Companies needing to re-evaluate and pilot technologies to determine what technology is capable of achieving this reduced mercury limit on the FGD discharges from each station. The Companies have been working with outside engineering resources, developed preliminary design reports, and a pilot test was conducted 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 NPDES permits.

In March 2023, the USEPA issued a new draft ELG rule that proposes additional constraints on wastewater discharges at power plants. The draft rule will undergo public notes and comment, and the USEPA has signaled that a final rule will be issued in 2024. The Companies will continue to monitor USEPA regulatory actions on this proposed 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 determining if retrofits may be required to the cooling water systems at either Clifty Creek or Kyger Creek, as well as the type of retrofit required, have been negotiated as a part of each plant's NPDES Permit renewals consistent with state regulatory obligations under 40 CFR Section 125.98(f). The terms and timelines associated with those retrofits are included in NPDES permit renewals.

The environmental rules and regulations discussed throughout the Environmental Matters footnote could require 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 because 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.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

As of December 31, 2022 and 2021, 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. The investments consist of 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.

Long-Term Investments— Assets measured at fair value on a recurring basis at December 31, 2022 and 2021, were as follows:

	Fair Value Measurements at Reporting Date Using		
2022	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (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	$ -
2021	**(Level 1)**	**(Level 2)**	**(Level 3)**
Equity mutual funds	$ 44,885,981	$ -	$ -
Equity exchange traded funds	22,078,933	-	-
Fixed-income municipal securities	-	107,781,573	-
Cash equivalents	126,581,690	-	-
Total fair value	$ 193,546,604	$ 107,781,573	$ -

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 and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2022 and 2021, are as follows:

	2022		2021	
	Fair Value	**Recorded Value**	**Fair Value**	**Recorded Value**
Total	$953,838,516	$989,976,349	$1,230,028,697	$1,122,110,945

11. LEASES

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, 2022.

The 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 year to 4 years.

Supplemental cash flow information related to leases was as follows:

Financing cash flows from finance leases	$946,103
Weighted average remaining lease term:	
Finance leases	3
Weighted average discount rate:	
Finance leases	4.73%

The amount in property under finance leases is $4,395,554 and $4,424,518 with accumulated depreciation of $1,796,855 and $1,293,804 as of December 31, 2022 and 2021, respectively.

Future maturities of finance lease liabilities are as follows:

Years Ending December 31	Finance
2023	$ 894,452
2024	847,412
2025	725,049
2026	148,436
Thereafter	-
Total future minimum lease payments	2,615,349
Less estimated interest element	183,915
Estimated present value of future minimum lease payments	$ 2,431,434

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.

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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, 2022 and 2021, 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, 2022 and 2021, 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.

Deloitte & Touche LLP

May 16, 2023

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

OVEC PERFORMANCE – A 5-YEAR COMPARISON

	2022	2021	2020	2019	2018
Net Generation (MWh)	**11,014,053**	10,071,966	9,025,018	11,238,298	12,146,856
Energy Delivered (MWh) to Sponsors	**11,047,708**	10,063,687	9,033,056	11,234,353	11,863,505
Maximum Scheduled (MW) by Sponsors	**2,161**	2,227	2,215	2,209	2,173
Power Costs to Sponsors	**$764,592,000**	$662,365,000	$605,270,000	$640,801,000	$644,114,000
Average Price (MWh) Sponsors	**$69.208**	$65.819	$67.006	$57.040	$54.294
Operating Revenues	**$761,499,000**	$623,425,000	$551,718,000	$614,667,000	$615,839,000
Operating Expenses	**$703,020,000**	$559,559,000	$480,383,000	$554,642,000	$523,196,000
Cost of Fuel Consumed	**$354,336,000**	$260,174,000	$231,316,000	$274,843,000	$277,369,000
Taxes (federal, state, and local)	**$12,078,000**	$12,293,000	$12,203,000	$8,418,000	$12,165,000
Payroll	**$53,135,000**	$53,052,000	$53,461,000	$55,491,000	$57,569,000
Fuel Burned (tons)	**5,004,318**	4,527,068	4,148,459	5,111,144	5,428,783
Heat Rate (Btu per kWh, net generation)	**10,626**	10,733	11,036	10,714	10,540
Unit Cost of Fuel Burned (per mmBtu)	**$3.05**	$2.41	$2.04	$2.28	$2.17
Equivalent Availability (percent)	**66.30**	70.8	78.9	78.2	76.6
Power Use Factor (percent)	**90.51**	76.56	60.80	76.23	84.19
Employees (year-end)	**507**	548	563	591	640

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

[2] **PAUL CHODAK III**, Columbus, Ohio
Executive Vice President - Generation
American Electric Power Company, Inc.

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.

AHMED B. PASHA, Arlington, Virginia
CFO, US Utilities & Conventional Generation
AES Corporation

[2] **DAVID W. PINTER**, Akron, Ohio
Executive Director, Business Development
FirstEnergy Corp.

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

[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

Indiana-Kentucky Electric Corporation

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

[2] **PAUL CHODAK III**, Columbus, Ohio
Executive Vice President - Generation
American Electric Power Company, Inc.

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] **DAVID W. PINTER**, Akron, Ohio
Executive Director, Business Development
FirstEnergy Corp.

OFFICERS—OVEC AND IKEC

PAUL CHODAK III
President

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

KASSANDRA K. MARTIN
Secretary and Treasurer

JULIE A. 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

W HEREAS, 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 ______________________

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Its ______________________

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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Its ______________________

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By ______________________
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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 ______________________

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Its ______________________

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Its ______________________

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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 [illegible signature]
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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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.

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Its ______________________

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Its ______________________

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Its ______________________

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Its ____________________

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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

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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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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 ______________________

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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 [signature]
Its Sr Vice President

LOUISVILLE GAS AND ELECTRIC COMPANY

By [signature]
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 ______________________

030860-0015-02023-Active 12026116.4

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

030860-0015-02023-Active 12026116.4

3

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur
Its President

APPROVED AS TO FORM:

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

U-15800 Docket Filing

2023 MPSC Staff Transfer Price Schedule

Background

The Commission's December 20, 2011 Commission Order in Case No. U-16582 directed the Michigan Public Service Commission Staff (Staff) to convene a technical conference with the following objectives:

- Address the appropriate inputs for developing transfer prices;
- Address the method for developing transfer prices; and
- Determine adequate measures to protect confidential information that recognizes the rights of the other parties to examine and test the evidence that may be used to develop transfer prices.

Staff convened the first technical conference on January 18, 2012 with DTE Electric Company (Formerly known as Detroit Edison Company), Michigan Environmental Council (MEC) and the Environmental Law and Policy Center (ELPC) to discuss inputs and the methodology for developing transfer prices and adequate measures to protect confidential information that allows for intervening parties to test the transfer price calculation methodology in the course of a contested case hearing. The parties agreed to work on solutions to the issues and provide the information electronically on February 15, 2012 and meet again on February 21 to discuss what each party had filed.

At the February 21, 2012 technical conference, Staff and MEC described the proposed transfer price calculation methodologies. The Attorney General also participated in the meeting. Additionally, processes to disclose necessary confidential information to parties yet adequately protect the data were discussed.

Staff convened a larger technical conference on May 30, 2012 with all Companies and interveners that participated in cases with transfer price issues. The goal of this larger technical conference was to try to reach consensus on a procedure to develop and update the transfer price schedules on a yearly basis. The parties attending the technical conferences provided discussion and feedback related to inputs and the methodology for developing transfer prices and measures to protect confidential information that allows for intervening parties to adequately test the transfer price calculation methodology in the course of a contested case.

Methodology

Staff's proposed methodology is to set yearly transfer price schedules that will cover the remaining time frame of the renewable energy planning period (2029) on a going forward basis. The transfer prices resulting from this methodology will be used by electric providers[1] as a point of reference.

[1] Currently Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, and Upper Michigan Energy Resources Corporation utilize transfer price schedules.

Staff believes transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a long term power purchase agreement for traditional fossil fuel electric generation. MCL460.1047 explains that when setting the transfer price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data, including but not limited to, locational marginal pricing. To best determine the value of the non-renewable component of PA 295 of 2008 compliant generation, Staff believes that for purposes of developing the MPSC Staff Transfer Price Schedule that the levelized cost of a new natural gas combined cycle (NGCC) plant would likely be analogous to the market price mentioned above. Starting with the U.S. Energy Information Administration's (EIA) levelized cost estimate for an advanced natural gas combined cycle facility, Staff built a trend line from the cost estimate to effectively follow the value of energy, capacity and inflation through 2029 that represents the cost of a new NGCC plant in each year.

To determine the slope of the trend line, Staff utilized data and projections provided by the EIA and the IHS Global Insight. Staff utilized fuel cost forecasts and producer price indices including utility natural gas, employment cost, industrial commodities, metals and metal products, and machinery and equipment. Consistent with common industry practice, Staff proposes that by analyzing projected construction cost components and fuel price forecasts throughout the plan period, Staff was able to calculate a proxy for market energy prices, capacity prices, ancillary benefits and the effect of inflation through the 2029 plan period.

Staff believes that, given current market conditions, the market will converge towards the price of a new NGCC plant every year. In an effort to accurately and effectively assign value to the non-renewable component of renewable energy generation and capacity, Staff developed this transfer price methodology so that it will result in a proxy for how a long term power purchase agreement would be structured. This methodology is the basis for the calculation of the MPSC Staff Transfer Price Schedules.

Data Protection

The Commission specified that a purpose of the technical conferences was to discuss adequate measures to protect confidential information but allows for intervening parties to adequately test the transfer price calculation methodology in the course of a contested case hearing. Staff has received permission from IHS Global Insight to allow the parties to a contested case to visit the MPSC offices and review the producer price indices used to create the trend line for Staff's transfer price schedule.

Timing

Staff will issue an updated MPSC Staff Transfer Price Schedule each spring in docket number U-15800. This is done to allow the electric providers time to incorporate the MPSC Staff Transfer Price Schedule into future renewable energy case filings for the calculation of the incremental cost of compliance.

In each contested Renewable Cost Reconciliation case, the electric provider will request a transfer price schedule be established and file its proposed transfer price schedule. Additionally, Staff will file the MPSC Staff Transfer Price Schedule.

Upon Michigan Public Service Commission approval of a transfer price schedule in the Renewable Cost Reconciliation, the transfer price schedule will be in effect until a new transfer price schedule is established in a subsequent proceeding. The most recently approved transfer price schedule will apply to all new renewable energy contracts and projects approved by the Commission. The most recently approved transfer price schedule will have no impact on contracts or projects that have already had transfer price schedules assigned.

2023 MPSC Staff Transfer Price Schedule

Staff presents its 2023 MPSC Staff Transfer Price Schedule. Using the same methodology as its 2012 – 2022 MPSC Staff Transfer Price Schedules,[2] Staff updated three components. These updates include:

- Updated Global Insight data.
- Utilized Energy Information Administration Annual Energy Outlook 2023 natural gas base case Henry Hub nominal gas price projection.
- Updated the Global Insight base year to 2027.

The 2023 Staff Transfer Price Schedule updates resulted in an overall average decrease in transfer prices when compared to the 2022 Staff Transfer Price Schedule.

[2] Due to the timing of the technical conferences, the 2012 MPSC Staff Transfer Price Schedule was not filed in this docket, but only filed in Renewable Cost Reconciliation Cases No: U-16662, U-16655 and U-16656 .

	2022 Transfer Price Schedule	2023 Transfer Price Schedule
2023	$62.97	$62.64
2024	$63.29	$62.11
2025	$64.59	$62.50
2026	$66.41	$65.44
2027	$68.00	$68.12
2028	$69.79	$69.68
2029	$71.82	$70.83

Levelized Cost Calculation

	NGCC	*notes*
Capacity MW	400	MW
Loading Factor	71.00%	% of time the unit would be dispatched if available
Equivalent Avail.	87.00%	% of time the unit would be available for dispatch.
Capacity Factor	61.77%	(Loading Factor)(Equivalent Availability)
Heat Rate Btu/kWh	6719	BTU/kWh
Fuel Cost $/MMBtu	$4.29	$ per Million BTU
Total Cost MM no AFUDC	$549.820	MM
AFUDC	$75.18	MM
Total Cost MM	$625.000	MM
Fixed Charge Rate	11.59%	% used to calculate fixed cost recovery component
Fixed O&M $/kW	$14.62	$/kW
Annual Lev. Fixed Cost MM	$72.44	MM
Total Annual Lev. Fixed Cost MM	$78.29	MM
Fixed Cost $/kWh	0.0362	$/kWh
Fuel Cost $/kWh	0.0288	$/kWh
Var. O&M $/kWh	0.0031	$/kWh
Total Var. Cost	0.0320	$/kWh
Total Cost $/kWh	**0.06812**	$/kWh

Overnight Cost (MM) 519.054486

AFUDC		**Total Overnight Cost (MM) in 2021 $**	**Inflation Rate**	**Cumulative**	**Finance Rate**
Year	GCC	$519.054	2%		6.56%
1	5%	26	26.47	26.47	1.74
2	30%	156	162.01	188.48	12.36
3	35%	182	192.79	381.27	25.01
4	30%	156	168.55	549.82	36.07
	1	519	549.820		75.18

Fixed price cost escalation: Fixed portion of levelized cost with 2027 as base year (2027=1)

Variable cost price escalation: Variable portion of levelized cost is multiplied by Nat Gas price forecast index, with 2027 as a base year (i.e. 2027=1).

	FIXED Cost Component	$36.17				VARIABLE	$31.95				
	Producer Price Index--Intermediate Materials	Producer Price Index--Industrial Commodities	Producer Price Index--Machinery & Equipment	Producer Price Index--Metals & Metal Products	Average	Producer Price Index--Utility Natural Gas	Employment Cost Index--Total Private Compensation	Weighted Average (Utility Nat Gas 70% ; Employment Cost 30%)		**2022 Transfer Price Schedule**	**2023 Transfer Price Schedule**
2023	-	-	-	-	36.74	-	-	25.89	2023	$62.97	$62.64
2024	-	-	-	-	35.13	-	-	26.97	2024	$63.29	$62.11
2025	-	-	-	-	35.07	-	-	27.43	2025	$64.59	$62.50
2026	-	-	-	-	35.47	-	-	29.97	2026	$66.41	$65.44
2027	-	-	-	-	36.17	-	-	31.95	2027	$68.00	$68.12
2028	-	-	-	-	36.98	-	-	32.69	2028	$69.79	$69.68
2029	-	-	-	-	37.82	-	-	33.00	2029	$71.82	$70.83

Source: EIA Annual Energy Outlook 2023
3&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=~r

	Period (Used for Levelized Calculation)	Henry Hub Using 2023 Annual Energy Outlook (Nominal)
2023	1	5.48
2024	2	4.34
2025	3	3.80
2026	4	3.41
2027	5	3.24
2028	6	3.25
2029	7	3.35
2030	8	3.54
2031	9	3.78
2032	10	4.07
2033	11	4.44
2034	12	4.75
2035	13	5.02
2036	14	5.15
2037	15	5.33
2038	16	5.63
2039	17	5.64
2040	18	5.99
2041	19	6.26

Discount Rate	**8.98%**
Net Present Value Fuel	**$38.48**
Levelized Fuel Price	**$4.29**

PJM CONE 2026/2027 Report

PREPARED BY

Samuel A. Newell
J. Michael Hagerty
Johannes Pfeifenberger
Bin Zhou
Travis Carless
Rohan Janakiraman
The Brattle Group

Sang H. Gang
Patrick S. Daou
Joshua C. Junge
Sargent & Lundy

PREPARED FOR

PJM Interconnection

APRIL 21, 2022

DATE

NOTICE

TABLE OF CONTENTS

Executive Summary iv

I. Introduction 10
I.A. Background 10
I.B. Study Objective and Scope 11
I.C. Analytical Approach 12

II. Reference Resource Selection 14
II.A. Process for Selecting Reference Resource 15
II.B. Evaluation of Candidates against Criteria 16

III. Natural Gas-Fired Combined-Cycle Plants 20
III.A. Technical Specifications 20
III.A.1. Plant Size, Configuration, and Turbine Models 22
III.A.2. Cooling System 23
III.A.3. Emissions Controls 24
III.A.4. Fuel Supply 24
III.B. Capital Costs 26
III.B.1. EPC Capital Costs 27
III.B.2. Non-EPC Costs 29
III.B.3. Escalation to 2026 Installed Costs 32
III.C. Operations and Maintenance Costs 34
III.C.1. Summary of O&M Costs 34
III.C.2. Annual Fixed Operations and Maintenance Costs 35
III.C.3. Variable Operation and Maintenance Costs 37
III.C.4. Escalation to 2026 Costs 37
III.D. Financial Assumptions 38
III.D.1. Cost of Capital 38
III.D.2. Other Financial Assumptions 46
III.E. Economic Life and Levelization Approach 47
III.F. CONE Results and Comparisons 48
III.F.1. Summary of CONE Estimates 48
III.F.2. Comparison to Prior CONE Estimates 48
III.G. Annual CONE Updates 50
III.H. E&AS Offset Methodology 51
III.I. Implications for Net CONE 53

III.I.1. Indicative E&AS Offsets ... 53
III.I.2. Indicative Net CONE ... 54
III.I.3. Comparison to "Empirical Net CONE" ... 56
III.I.4. Uncertainty Analysis ... 57

IV. Natural Gas-Fired Combustion Turbines ... 58
IV.A. Technical Specifications ... 58
IV.B. Capital Costs ... 59
IV.B.1. Escalation to 2026 Installed Costs ... 62
IV.C. Operations and Maintenance Costs ... 62
IV.D. CONE Results and Comparisons ... 63
IV.E. Implications for Net CONE ... 65
IV.E.1. Indicative E&AS Offsets ... 65
IV.E.2. Indicative Net CONE ... 67

V. Battery Energy Storage Systems (BESS) ... 69
V.A. Technical Specifications ... 69
V.B. Capital Costs ... 72
V.C. Operation and Maintenance Costs ... 74
V.D. CONE Estimates ... 75
V.E. Implications for Net CONE ... 77
V.E.1. Indicative E&AS Offsets ... 77
V.E.2. Indicative Net CONE ... 78

VI. List of Acronyms ... 80

Appendix A : Combined-Cycle and Combustion Turbine Cost Details ... 82
A.1 Technical Specifications ... 82
A.2 Construction Labor Costs ... 84
A.3 Net Startup Fuel Costs ... 85
A.4 Gas and Electric Interconnection Costs ... 86
A.5 Land Costs ... 88
A.6 Property Taxes ... 88

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).

Reference Resource

The reference resource should be feasible to build within the three-year period between the Base Residual Auction and the delivery year; economically viable, as indicated by actual merchant entry and competitive costs; and amenable to accurate estimation of its Net CONE.

We recommend shifting the reference resource from the current natural gas-fired combustion turbine (CT) to a natural gas-fired combined cycle (CC) because the CC best meets these criteria in PJM. The CC is clearly economically viable, as it has the largest amount of recent merchant entry and a lower estimated Net CONE than the other candidate resources. CTs continue to be less economic than CCs, consistent with their extremely limited entry in the recent past. Selecting the CT as the reference resource would set the demand curve in a way that would perpetuate excess supply in PJM (although could be considered a way to buy extra reliability insurance for a premium). We considered BESS as a potential source of “clean capacity” for areas with more stringent environmental regulations that could limit the feasibility of developing new natural gas-fired resources. However, its estimated Net CONE is much higher than the CC without there being a clear enough indication at this time that the CC could not be built. We recommend that PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate.

For each resource evaluated, we developed technical specifications of a complete plant reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. The CC specifications are for a 1,182 MW plant with two trains of a single-shift combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two “single-shaft 1x1”s) including 123.9 MW of duct-firing capacity. The CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[1] The CC has a higher-heating value (HHV) average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. CT specifications included a single simple cycle GE 7HA.02 with 367 MW capacity and a 9,189 Btu/kWh full-load average heat rate. BESS specifications are for a 200 MW 4-hour battery with 13% initial oversizing and capacity augmentation planned every 5 years to maintain charge capability and duration.

[1] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

Cost Analysis

For CC and CTs in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. For BESS, we performed a top-down cost analysis based on a less detailed plant design and recent experience estimating costs for developers.

We translate the estimated costs into the net revenues the resource owner would have to earn in its first year to enter the market, assuming a 20-year economic life for the CC and CT and net revenues on average remain constant in nominal terms over that timeframe. We believe these assumptions are reasonable given widespread concern expressed by developers in the stakeholder community that gas-fired generation has limited value beyond the assumed 20-year life in a policy environment that increasingly disfavors greenhouse gas-emitting generation (and even capacity). For the BESS, we assumed a shorter 15-year economic life based on a representative degradation profile and warranty term typical for the selected battery technology.

To estimate the net revenue the reference resource would need to earn to achieve the required return on and return of capital, we estimated the cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.

Table ES-1 below shows the resulting 2026/27 CONE estimates for CCs for each CONE Area. The CONE values are 56% higher (or $180/MW-day ICAP) than PJM's 2022/23 values from the 2018 CONE Study, averaged across all four CONE Areas. Three factors explain this increase:[2]

- Declining Bonus Depreciation**:** Bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $25/MW-Day (ICAP) to CONE.
- Cost Escalation: The costs of materials, equipment, and labor have escalated and will continue to escalate at a faster rate than expected at the time of the last study. These cost increases add $92/MW-Day (ICAP) to CONE, relative to the 2022/23 estimate.

[2] These factors add to more than $180/MW-day (ICAP) due to offsets from a slightly lower cost of capital that reduces CONE by $4/MW-day (ICAP).

- Plant Design Changes: The use of dry-cooling, building a gas-only plant (without dual fuel capability) with firm gas transportation contracts under more constrained environmental permitting regimes (along with smaller increases from 2x1 to double-train 1x1 CCs) adds $66/MW-Day (ICAP).

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

There is considerable uncertainty in the development of the estimated CONE values for the reference resources, particularly regarding volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, and the costs could be greater still if technologies are more constrained by environmental regulations. For BESS, the uncertainty in levelized costs is even greater because of rapidly-changing cost of equipment, currently unresolved applicability of tax credits, and other complications if combined into hybrid plants (and even greater uncertainty with E&AS offsets).

E&AS Methodology

We continue to recommend using a forward-looking E&AS offset, as described in our 2020 testimony and as PJM implemented for its 2022/2023 capacity auction. This approach reflects future market conditions that developers face and avoids distortions from anomalous conditions in a backward-looking approach. We recommend continuing to use the same liquid hubs for natural gas and electricity, and scaling ancillary services prices to energy prices. We recommend that PJM should not include regulation revenues in its estimation of the E&AS offset since the market for regulation is too small to provide substantial additional revenue to capacity entering the PJM market at scale. These recommendations all apply equally to the CT, along with a recommended 10% increase in the estimated day-ahead gas costs to account for having to buy gas in the less liquid intraday market when committed in the real-time market. For BESS, we recommend using the same forward prices along with a virtual dispatch as PJM has been performing with the PLEXOS model.

Application of this forward methodology to CCs leads to indicative E&AS offset values for the CC of $209/MW-day for the RTO, $222 for MAAC, $189 for EMAAC, and $249 for SWMAAC (all denominated in 2026 dollars per UCAP MW-day). This is about $10-30/MW-day greater than the values used for MOPR reviews for the 2022/23 auction, with inflation more than offsetting other factors that tend to decrease the E&AS offset.

Implications for Net CONE and VRR Curve

Elevated Net CONE. With substantially higher CONE and only slightly higher indicative E&AS offsets, indicative CC Net CONE is correspondingly higher, at $307/MW-day for the RTO, $294 for MAAC, $329 for EMAAC, and $257 for SWMAAC (all denominated in 2026 dollars and UCAP MW). This is about $154 higher than CC Net CONE for 2022/23; it is similarly above recent capacity market clearing prices when new CCs entered, and this is consistent with cost escalation, more constrained plant designs, and tax laws; plus likely increased reluctance to invest given a regulatory and market environment that is increasingly favoring clean energy.

Slightly elevated VRR Curve. In spite of significant cost increases, updated CC Net CONE is only $47/MW-day higher than CT Net CONE for 2022/23, since CCs are more economic than CTs. Inefficiently maintaining the CT as the reference resource would increase Net CONE by much more. Thus, switching the reference resource to CCs would moderate the increase and should support procuring reserves closer to target.

Heightened Uncertainty. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we tested robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

I. Introduction

I.A. Background

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which the Variable Resource Requirement (VRR) curve sets the "demand" for capacity. The VRR curve is designed primarily to procure sufficient capacity for maintaining resource adequacy according to traditional standards. The longstanding resource adequacy objectives are to avoid supply shortages in expectations all but once in ten years system-wide (i.e., Loss of Load Expectation or LOLE of 0.1 events/yr), with no more than 0.04 LOLE incremental risk in the Locational Deliverability Areas (LDAs). With probabilistic modeling conducted by PJM, these objectives are translated into Reliability Requirements expressed in terms of megawatts of unforced capacity (MW UCAP).

The VRR curves are centered approximately on a target point corresponding to the Reliability Requirements, at a price given by the estimated long-run marginal cost of capacity, termed the "Net Cost of New Entry (Net CONE)." Rather than a vertical line, the VRR is a curve with nonzero demand above the target to recognize the value of incremental capacity, and with a slope to help mitigate price volatility (as addressed in a separate VRR Curve Study report we are publishing concurrently with this report).

For the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would be willing to enter the market if needed. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would require (in combination with its expected net revenues from the energy and ancillary services markets) to recover its capital and fixed costs, given reasonable expectations about future cost recovery. Thus, Net CONE is given by gross CONE minus the projected Energy and Ancillary Services revenue (E&AS Offset).

Following its tariff, PJM has traditionally estimated Net CONE for a new gas-fired combustion turbine (CT) entering in each of four CONE Areas.[3] Gross CONE values have been determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[4] Shortly before each Base Residual Auction, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction.

PJM also develops Net CONE estimates for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[5] This has less relevance than in past since PJM filed and FERC accepted a revision to MOPR rules that limit its applicability.

I.B. Study Objective and Scope

PJM retained consultants at The Brattle Group and Sargent & Lundy to assist PJM and stakeholders in its quadrennial review. Per the PJM tariff, the scope of the Quadrennial Review is to review the VRR curve and its parameters, including the Cost of New Entry and the E&AS Offset methodology. To that end, a separate, concurrently issued report addresses the shape of the VRR curve. This report:

- Develops CONE estimates for new CT and CC plants and one "clean technology" in each of the four CONE Areas for the 2026/27 Base Residual Auction (BRA) and proposes a process to update these estimates for the following three BRAs;
- Reviews the E&AS offset methodology
- Recommends the most appropriate reference resource whose cost will best indicate the price at which developers would be willing to add capacity.

To estimate CONE for each resource type, we aim to represent the plant configuration, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, not unique sites with unusual characteristics. We estimate costs by specifying the

3 The four CONE Areas are: CONE Area 1 (EMAAC), CONE Area 2 (SWMAAC), CONE Area 3 (Rest of RTO), and CONE Area 4 (WMAAC). PJM reduced the CONE Areas from five to four following the 2014 triennial review and incorporated Dominion (formerly CONE Area 5) into the Rest of RTO region.

4 PJM 2017 OATT, Section 5.10 a.

5 PJM 2017 OATT, Section 5.14 h.

reference resource and site characteristics, conducting a bottom-up analysis of costs, and translating the costs to a first-year CONE.

We provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of CONE, but also inform the range of uncertainty, a key consideration in designing the VRR curve, as discussed in our separate report.

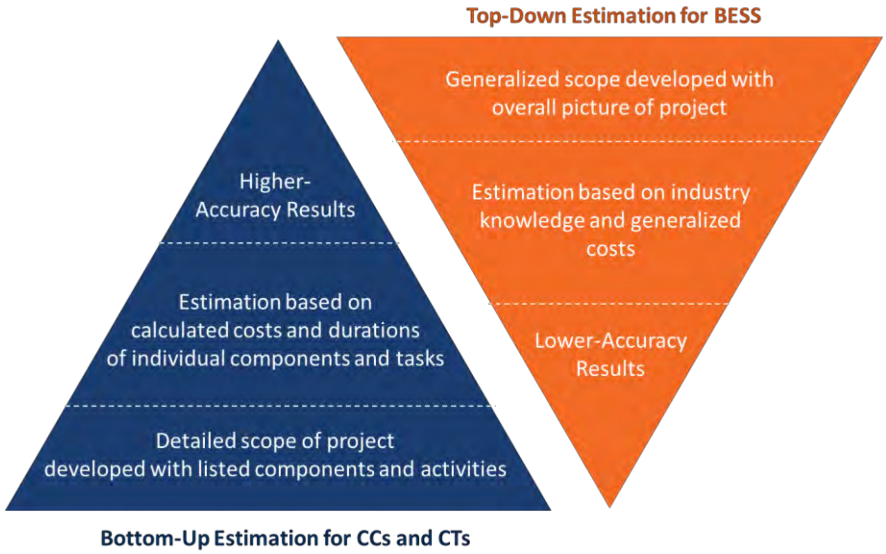
I.C. Analytical Approach

Our starting point is to identify the most appropriate technology to serve as the reference resource for the VRR curve. As discussed in Section II, we identified criteria for selecting the reference resource then evaluated a broad range of resource types against those criteria in an initial screening analysis. This narrowed the choices to a CC, a CT, and BESS, for each of which we analyzed the costs more extensively further—and ultimately recommended using the CC as the reference resource for all locations.

For each of the three identified resources, we estimated CONE for the four CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant characteristics and site characteristics based on: (1) our analysis of the predominant practices of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. Our analysis for selecting plant characteristics for each CONE Area is presented in Section 0 of this report.

We developed comprehensive, bottom-up cost estimates of building and maintaining the reference CC and CT in each of the four CONE Areas. To present a reasonable order-of-magnitude cost estimate for the BESS, we utilized a generalized, top-down approach. Figure 1 describes the attributes of each approach.

FIGURE 1: ATTRIBUTES FOR BOTTOM-UP AND TOP-DOWN ESTIMATION METHODS



Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on developers' long-term market view and how this long-term market view impacts the expected cost recovery path for the plant—specifically whether a plant built today can be expected to earn as much in later years as in earlier years.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Reference Resource Selection

The purpose of selecting a reference resource and developing administrative Net CONE estimates is only to set a VRR curve that aims to procure enough resource adequacy credits. The choice of reference resource does not dictate which resources will enter the market. The administrative Net CONE value does not determine capacity prices; long-run prices depend primarily on the supply curve. Still, as the VRR curve is likely to remain sloped and anchored on our estimate of Net CONE, we aim to estimate Net CONE as accurately as possible, and that starts with a choice of the reference resource.

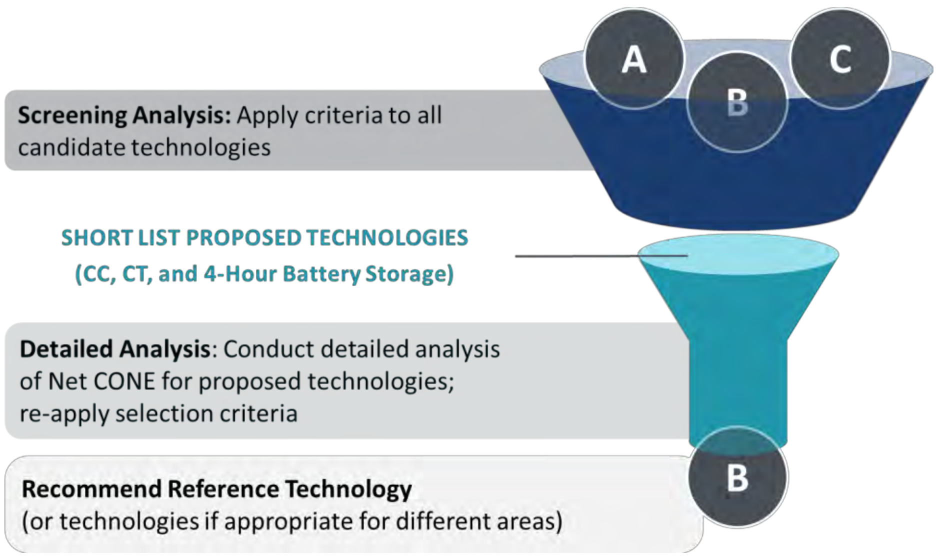
PJM has always used a reference resource, specifically a CT, to estimate Net CONE but asked us to evaluate its continued suitability for representing the cost at which suppliers are willing to bring significant amounts of capacity to PJM. We also considered CCs and a range of other technologies, including BESS as a possible “clean technology” for areas with more stringent environmental regulations. Finally, we also considered the possibility of relying on “empirical Net CONE,” i.e. the price at which suppliers have willingly offered new capacity into recent auctions, rather than identifying a specific technology and estimating its net cost for future entry into the market. All possibilities were evaluated against a set of criteria for meeting RPM objectives.

In order to meet RPM reliability objectives with least risk of procuring far above or below target, we recommend switching to a CC as the reference resource. This aligns the VRR curve with observed entry of a technology that is feasible and most economic to build on a merchant basis, and whose Net CONE can be estimated relatively accurately. By contrast, CTs are not being built and are estimated to cost 20% more, on net, for capacity. Other technologies are similarly less economic or otherwise did not meet our selection criteria. Even in areas with more stringent environmental regulations, we did not identify a clear need to adopt a non-emitting reference resource at this time. Finally, empirical Net CONE is a useful benchmark but is not directly suitable because it does not reflect current market conditions affecting the costs of materials, equipment, and labor, nor the regulatory outlook that affects the design of the resources and their future revenue recovery.

II.A. Process for Selecting Reference Resource

We conducted the analysis in several steps, as shown in Figure 2 below. First, we developed criteria for choosing a reference resource; second, we identified a broad range of technologies to evaluate at a high-level against those criteria, resulting in a short list for detailed cost and E&AS analysis; finally, we applied the selection criteria again to select the single most appropriate technology to serve as the reference resource, reflecting the updated net costs of those resources.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS



In consultation with PJM and its stakeholders, we developed the reference resource selection criteria. The foundational objective of the selection criteria was to identify the resource that best supports the RPM's broader objective of procuring enough capacity to meet resource adequacy goals. Given that, we developed three selection criteria.

The first and most basic of these criteria is that the resource has to be feasible to build in the (slightly more than) three-year timeframe between the Base Residual Auction and the Delivery Year, so that high clearing prices in an auction can draw in potential projects when needed/economic.

The second criterion is that the resource must be an economic source of incremental capacity. Otherwise, anchoring the VRR curve on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and lower estimated Net CONE, and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review. The reason for focusing on merchant entrants is partly to ensure that the VRR curve is set high enough to attract merchant entry in the future. It is also to avoid including policy-supported payments (such as renewable energy credits, or RECs) in the E&AS Offset, since such payments are difficult to assess absent broad competitive markets and are limited to the amount of capacity that the policy is intended to achieve. Moreover, such an exercise would suffer from circularity since the necessary level of policy payments needed to support target reasons are in part set by capacity price itself.

The third criterion is that the resource's Net CONE can be estimated accurately. If Net CONE is mis-estimated, the VRR curve will procure more or less capacity than desired. Accurate estimation depends on the certainty of plant designs and their costs and the ability to estimate E&AS offsets using market data. It also depends on the scalability of a standardized resource, not subject to rapid increases in costs as the best sites are exhausted, in which case the cost would depend strongly on penetration. Finally, estimation accuracy also depends on the capacity rating of resources relative to their nameplate. Lower ratings (i.e., low ELCC) magnify the effect of estimation errors on the cost per qualified MW.

Figure 3 summarizes these criteria and sub-criteria for evaluating each candidate resource type.

FIGURE 3: REFERENCE RESOURCE SELECTION CRITIERIA

Feasible to build for the delivery year, given local laws/regulations and technical factors

Economic source of incremental capacity
- Demonstrated by recent merchant entry, not in anomalous situations
- Not having a Net CONE much higher than other candidates
- Likely to remain economic through the end of the review period (2029/30)

Costs, net E&AS revenues, and RA contribution per MW can be assessed accurately
- Evidence of capital and operating costs exists from commercial experience
- Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
- Has stable UCAP/ICAP ratio or ELCC, rather than changing steeply with penetration or fleet composition
- Has high UCAP/ICAP ratio or ELCC, else uncertainties are amplified per kW UCAP
- Not largely dependent on revenues that are difficult to forecast (AS, energy volatility, RECs)

II.B. Evaluation of Candidates against Criteria

The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems (BESS), hybrid photovoltaic (PV)-BESS, utility-scale PV, onshore wind, energy efficiency and demand response, uprates/conversions, and emerging technologies. Screening each of these against the evaluation criteria was straightforward in most cases, as shown in Table 1 below. For example, wind resources currently are not entering as a merchant resource without policy support in PJM, corresponding to its relatively high costs, and its Net CONE would be difficult to assess accurately due to its low ELCC rating that magnifies cost estimation errors. Energy efficiency, DR, and uprates/conversions were eliminated because of highly non-uniform costs across measures and sites, and scalability challenges with any particular type of measure.

TABLE 1: INITIAL REFERENCE RESOURCE SCREENING ANALYSIS

Technology	Feasible to Build for DY	Economic Source of Capacity	Accuracy of Net CONE Estimates	Screening Decision
Gas CC	Yes	Yes	High	Consider as leading candidate
Gas CT	Yes	Unclear (few built, higher Net CONE)	High	Consider for further analysis
Battery Storage	Yes	Unclear (not standalone cleared in RPM)	Medium (falling costs; AS-dependence; ELCC stability?)	Consider for further analysis
Hybrid PV-BESS	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Utility-Scale PV	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Wind	Yes	Unclear (is any entering as merchant?)	Low (REC-dependence; low ELCC, stability)	Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR
Energy Efficiency/ DR	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Uprates/ Conversions	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Emerging Technologies	No	None	Low	Eliminate: Infeasible to build

Based on stakeholder feedback, we included one non-emitting resource in our CONE and E&AS analysis, selecting BESS due to its lower uncertainty in accurately estimating its Net CONE value compared to utility-scale solar PV and hybrid PV-BESS. Utility-scale solar PV ELCC values are highly uncertain as they decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV investments in PJM depend on RECs, the price of which is uncertain, which increases Net CONE uncertainty; REC prices also depend on capacity prices, creating a circularity that confounds estimating the capacity price at which PVs will enter. Hybrid PV-BESS resources are similarly uncertain as utility-scale solar PV in terms of the ELCC value and dependence on RECs for entry, plus the additional uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

That left CC, CT, and BESS as finalists. Ultimately, CCs best met the selection criteria, as summarized in Table 2 below. They are the most economic and are being built by developers. CTs continue not to be built, consistent with our estimate that their RTO Net CONE is about 20% higher than the CC, as shown in this report. In addition, CC Net CONE can be estimated relatively accurately. The conventional wisdom used to be that CCs are subject to more estimation error in E&AS Offsets, since their E&AS Offsets are larger. We disagree. The benchmark for "accuracy" should be the value that investors anticipate in the market. That benchmark is not directly observable, but there is more market data available to anticipate E&AS Offsets for CCs than CTs. CCs' net E&AS revenues can be fairly accurately approximated assuming 5x16 operation and applying observable futures prices for 5x16 on-peak blocks. No such benchmark is available for CTs that run less frequently when prices spike, so we rely on historical estimates that may not be representative of the future delivery year due to historical anomalies and evolving market conditions. Finally, CTs face less transparent gas procurement costs since they are committed and dispatched day-of.

TABLE 2: BASIS FOR SELECTING THE RECOMMENDED REFERENCE RESOURCE

Technology	Feasible to Build for Delivery Year	Economic Source of Capacity	Accuracy of Net CONE Estimates
Gas CC	**Yes**	**Yes** (significant recent entry; lowest 2026/27 Net CONE)	**Highest**
Gas CT	**Yes** (may be infeasible to build in NJ)	**Unclear** (few recently built; Net CONE 20% higher than CC)	**High** (higher forward E&AS uncertainty due to lack of forward pricing matching CT dispatch)
Battery Storage	**Yes**	**Unclear** (no cleared capacity to date; highest 2026/27 Net CONE among candidates)	**Low** (uncertain future AS revenues; falling costs)

We also considered "empirical Net CONE" based on the clearing price at which new capacity has proven willing to enter in the past several auctions. Historical data do indeed provide a useful reference point for Net CONE, although we rejected using it directly because it is backward-looking at a time when fundamentals are changing profoundly due to cost escalation and clean energy policies.

III. Natural Gas-Fired Combined-Cycle Plants

III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

[6] For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

[7] The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

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

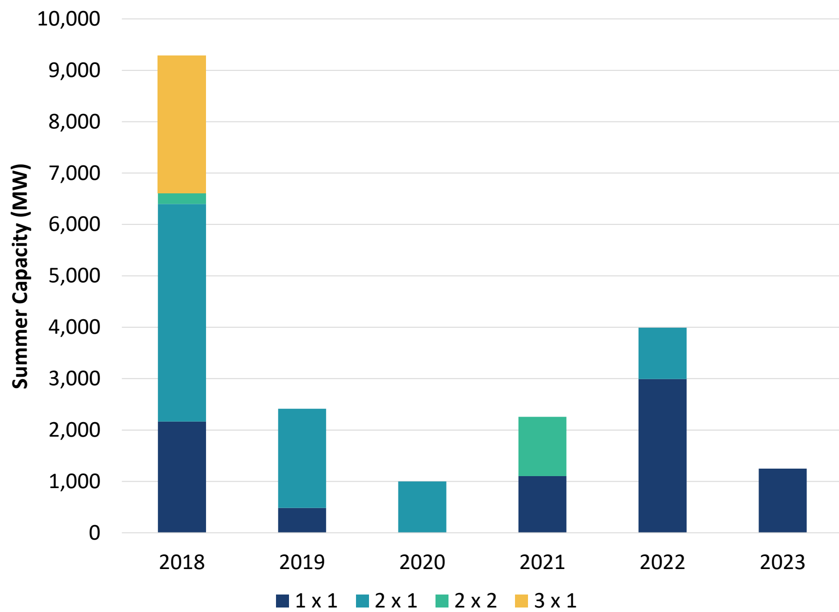
Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 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.

III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018



Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Number of Trains	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*	2023 *(MW)*	Total Capacity *(MW)*	Capacity Share *(%)*
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize “wet” cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

[8] PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

FIGURE 5: COOLING SYSTEM FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018

Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

III.A.3. Emissions Controls

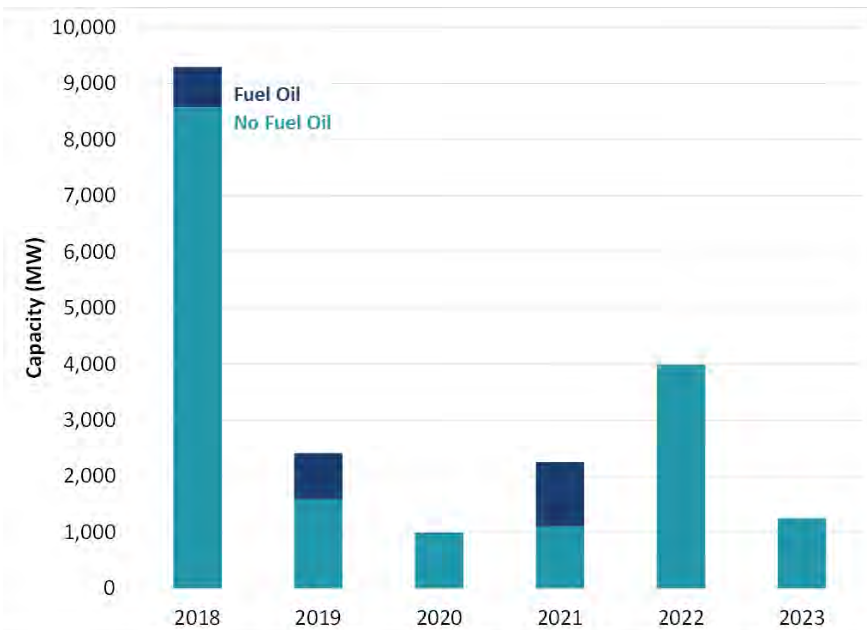
The reference CC is assumed to utilize selective catalytic reduction (SCR) systems as a nitrogen oxide (NOx) emissions control technology and CO catalyst systems as a carbon monoxide (CO) emissions control technology. The SCR system and CO catalyst adds an incremental cost of $72 million (in 2021 dollars) to the capital costs. A more detailed discussion of emissions controls can be found in the 2018 PJM CONE study.

III.A.4. Fuel Supply

Natural gas-fired plants can be designed to operate solely on gas or with “dual-fuel” capability to burn either gas or diesel fuel oil. Dual-fuel plants can switch to oil when gas becomes unavailable or prohibitively costly due to pipelines becoming fully utilized and congested. Plants without dual-fuel capability can ensure access to their fuel supply through firm transportation contracts, although such contracts cost more than dual-fuel capability in most locations.[9]

Developers have moved away from installing dual-fuel capability on new CCs. Figure 6 below shows that only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel since 2018; data from PJM confirms that almost all are instead firming their availability with firm gas transportation contracts.

FIGURE 6: DUAL-FUEL CAPABILITY FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted).

Instead, we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2016/2017 BRA obtain firm transportation service to ensure adequate fuel supply.[10] Based on these trends, we updated our assumption from the

9 Eastern Interconnection Planning Collaborative, "Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives," accessed September, 2017, http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

10 PJM provided the fuel supply arrangements for 20,848 MW of new gas plants that first cleared the capacity market in the 2016/2017 BRA to the 2020/2021 BRA, including firm transportation, dual fuel capability, and installing gas laterals to multiple pipelines.

2018 PJM CONE study for the CC reference resource to obtain firm gas supply across all CONE areas.[11] The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs in the following section.

III.B. Capital Costs

Plant capital costs are costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2021 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix A.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost for an online date of June 1, 2026 by escalating the 2021 costs using escalation rates provided by Sargent & Lundy. The 2026 "installed cost" is the present value of the construction period cash flows as of the end of the construction period, using the monthly drawdown schedule and the cost of capital for the project.

Based on the technical specifications for the reference CC described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 6 below. The maximum variation between overnight capital costs between CONE areas is $100/kW, similar to the $94/kW from the 2018 PJM CONE study. The methodology and assumptions for developing the capital cost line items are described further below.

[11] We recommended in the 2018 PJM CONE study dual-fuel capabilities in all CONE Areas except SWMAAC. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

TABLE 6: PLANT CAPITAL COSTS FOR CC REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1171 MW*	*1174 MW*	*1144 MW*	*1133 MW*
Owner Furnished Equipment				
Gas Turbines	$155.3	$155.3	$155.3	$155.3
HRSG / SCR	$80.7	$80.7	$80.7	$80.7
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$320.7**	**$320.7**	**$320.7**	**$320.7**
EPC Costs				
Equipment				
Other Equipment	$86.3	$86.3	$86.3	$86.3
Construction Labor	$365.5	$283.3	$297.1	$330.5
Other Labor	$75.5	$69.0	$70.1	$72.7
Materials	$75.5	$75.5	$75.5	$75.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$98.5	$89.6	$91.1	$94.7
EPC Contingency	$108.4	$98.6	$100.2	$104.2
Total EPC Costs	**$871.4**	**$763.9**	**$782.0**	**$825.6**
Non-EPC Costs				
Project Development	$59.6	$54.2	$55.1	$57.3
Mobilization and Start-Up	$11.9	$10.8	$11.0	$11.5
Net Start-Up Fuel Costs	-$13.9	-$14.0	-$9.8	-$13.5
Electrical Interconnection	$25.3	$25.4	$24.7	$24.5
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$2.2	$1.8	$1.0	$1.8
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$6.0	$5.4	$5.5	$5.7
Owner's Contingency	$10.0	$9.4	$9.7	$9.7
Emission Reduction Credit	$2.3	$2.3	$2.3	$2.3
Financing Fees	$29.2	$26.7	$27.2	$28.1
Total Non-EPC Costs	**$166.4**	**$155.8**	**$160.6**	**$161.3**
Total Capital Costs	**$1,358.5**	**$1,240.5**	**$1,263.3**	**$1,307.6**
Overnight Capital Costs ($million)	**$1,359**	**$1,240**	**$1,263**	**$1,308**
Overnight Capital Costs ($/kW)	**$1,160**	**$1,057**	**$1,104**	**$1,154**
Installed Cost ($/kW)	**$1,255**	**$1,144**	**$1,195**	**$1,248**

III.B.1. EPC Capital Costs

III.B.1.i. Project Developer and Contract Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

III.B.1.ii. Equipment and Materials

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines. The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. We assume all purchases for plant equipment are exempt from sales tax.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

III.B.1.iii. Labor

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Similar to the 2018 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region in 2021, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix A.

III.B.1.iv. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to the Owner Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Capital cost estimates include an EPC contractor fee of 10% of total EPC and OFE costs for CC facilities based on S&L's proprietary project cost database.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, including the contractor fee. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.7% to 9.8% of the pre-contingency overnight capital costs.

III.B.2. Non-EPC Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

III.B.2.i. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.ii. Net Startup Fuel Costs

Before commencing full commercial operations, the new CC plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix A.

III.B.2.iii. Emission Reduction Credits

Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as attainment. ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are determined based on the annual NOx and volatile organic compounds (VOC) emissions of the facility and offset ratio which is dependent on the specific plant location. Similar to our assumption from the 2018 PJM CONE study, we assumed a cost of $5,000/ton for all CONE Areas and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2021 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

III.B.2.iv. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. We assume the gas interconnection will require a metering station and a five-mile lateral connection, similar to the 2018 PJM CONE Study. From the data summarized in Appendix A, we estimate that gas interconnection costs will be $29.5 million (in 2021 dollars) based on $5.1 million/mile and $4.0 million for a metering station. Similar to the 2011, 2014, and 2018 PJM CONE studies, we found no relationship between pipeline width and per-mile costs in the project cost data.

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using recent project data provided by PJM with the online service year between 2018 and 2021, we selected 17 projects (3,700 MW of total capacity) that are representative of interconnection costs for a new gas CCs and calculated a capacity-weighted average electrical interconnection cost of $18.9/kW (in 2021 dollars) for these projects, 5% lower than the 2018 PJM CONE Study. The estimated electric interconnection costs are between $21.4 and $22.2 million for CCs (in 2021 dollars). Appendix A presents additional details on the calculation of electric interconnection costs.

III.B.2.v. Land

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We assume that 60 acres of land are required for the CC. Table 7 shows the resulting costs (see Appendix A for more detail).

TABLE 7: COST OF LAND PURCHASED FOR REFERENCE CC

CONE Area	Land Price *($/acre)*	Plot Size Gas CC *(acres)*	Cost Gas CC *($m)*
1 EMAAC	$36,600	60	$2.20
2 SWMAAC	$29,500	60	$1.77
3 Rest of RTO	$16,400	60	$0.98
4 WMAAC	$30,600	60	$1.84

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

III.B.2.vi. Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel inventories are 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.vii. Owner's Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

[12] The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

2026.[13] The real escalation rate for each cost category was then added to the assumed inflation rate to determine the nominal escalation rates, as shown in Table 8.

TABLE 8: CC AND CT CAPITAL COST ESCALATION RATES (% PER YEAR)

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.00%	2.91%
Labor	1.60%	4.51%

Sources and notes: Escalation rates on equipment and materials costs are derived from the BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from the current overnight costs to the month they would be incurred using the monthly capital drawdown schedule developed by S&L for an online date in June 2026.

We escalated several cost items in a different manner:

- Land: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2026 online date, the land is thus assumed to be purchased in late 2022 such that current estimates are escalated 1 year using the long-term inflation rate of 2.9%.
- Net Start-Up Fuel and Fuel Inventories: no escalation was needed as we forecasted fuel and electricity prices in 2026 dollars.
- Electric and Gas Interconnection: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior to completion, consistent with the 2018 PJM CONE Study; the interconnection costs have been escalated specifically to these months.
- Emission Reduction Credits: escalated to the online start date of June 2026 using the long-term inflation rate of 2.91%.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2026 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate

[13] The near-final CONE results presented on March 25, 2022 assumed an inflation rate of 2.0%.

the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

III.C. Operations and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including contracted services, property tax, insurance, labor, maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated *variable* O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations.

III.C.1. Summary of O&M Costs

Table 9 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2026.

TABLE 9: O&M COSTS FOR CC REFERENCE RESOURCE

	CONE Area			
O&M Costs	**1 EMAAC** *1171 MW*	**2 SWMAAC** *1174 MW*	**3 Rest of RTO** *1144 MW*	**4 WMAAC** *1133 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.8	$0.8	$0.8	$0.8
Labor	$5.2	$5.6	$4.0	$4.1
Maintenance and Minor Repairs	$6.6	$6.7	$6.0	$6.1
Administrative and General	$1.4	$1.4	$1.2	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.2
Property Taxes	$3.0	$16.4	$9.5	$2.9
Insurance	$8.2	$7.4	$7.6	$7.8
Firm Gas Contract	$10.0	$12.4	$16.4	$14.5
Working Capital	$0.2	$0.1	$0.1	$0.1
Total Fixed O&M (2026$ million)	**$36.8**	**$52.6**	**$46.8**	**$38.8**
Levelized Fixed O&M (2026$/MW-yr)	**$31,500**	**$44,900**	**$40,900**	**$34,200**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	0.76	0.76	0.77	0.77
Total Variable O&M (2026$/MWh)	**2.08**	**2.07**	**2.12**	**2.14**

III.C.2. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

III.C.2.i. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, we include the monthly payments specified in the LTSA as fixed O&M costs and the larger costs associated with run-time and starts as variable O&M.

III.C.2.ii. Insurance and Asset Management Costs

We estimate insurance cost of 0.6% of the overnight capital cost per year, from the 2018 PJM CONE study based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of natural gas-fired plants in operation.

III.C.2.iii. Property Tax

We maintained our bottom-up approach for estimating property and personal taxes from the 2018 PJM CONE study. We researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states.[14] The tax rates assumed for each CONE Area are summarized in Table 10 with additional details in Appendix A.

[14] See the 2018 PJM CONE study for a detailed discussion on our bottom up approach.

TABLE 10: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

	Real Property Tax	Personal Property Tax	
	Effective Tax Rate	Effective Tax Rate	Depreciation
	(%)	*(%)*	*(%/yr)*
1 EMAAC			
New Jersey	3.8%	n/a	n/a
2 SWMAAC			
Maryland	1.1%	1.3%	3.30%
3 RTO			
Ohio	1.9%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	2.7%	n/a	n/a
4 WMAAC			
Pennsylvania	3.8%	n/a	n/a

Sources and notes: See Appendix A for additional detail on inputs and sources.

We assume that assessed value of real property will escalate in future years with inflation. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years.

III.C.2.iv. **Working Capital**

Based on our approach in the 2018 PJM CONE study, we estimate the costs of maintaining the working capital requirement assuming that the working capital requirement is approximately 0.5% of overnight costs and a borrowing rate for short-term debt of 2.1%.[15]

III.C.2.v. **Firm Transportation Service Contracts**

We maintained our approach for estimating firm transportation service contracts from the 2018 PJM CONE study for the SWMAAC CONE Area for the reference CC. However, we utilized the reservation and usage charges for pipelines servicing EMAAC, Rest of RTO, and WMAAC under FT-1 rate schedules. Table 11 summarizes the pipelines we assumed for each CONE area and the representative firm gas capacity costs. We assume the reference CC commit to procuring firm gas transportation on an annual basis.

[15] 15-day average 3-month bond yield as of January 31, 2022, BFV USD Composite (BB), from Bloomberg.

TABLE 11: CONE AREA PIPLEINES AND FIRM GAS CAPACITY COSTS

	CONE Area	Pipelines	Representative Firm Gas Capacity Cost *(2026$ per Dth/d per Mth)*
1	**EMAAC**	Transco Zone 6 (non-NY), Transco Zone 6 (NY)	$4.50
2	**SWMAAC**	Dominion Cove Point	$5.56
3	**Rest of RTO**	Chicago, Columbia-Appalachia TCO, Dominion South, Michcon, Transco Zone 5	$7.54
4	**WMAAC**	Tennessee 500L, TETCO M3	$6.73

To estimate the costs of acquiring firm transportation service for SWMAAC we escalated the Cost of Firm Gas Capacity per Month of $4.96 (2022$ per Dth/d) from the 2018 PJM CONE study by 2.9% annually to 2026. For the EMAAC, Rest of RTO, and WMAAC CONE Areas, we combined the reservation and usage rates, resulting in a tariff rate for each pipeline. Then the pipeline tariff rates are averaged and escalated by 2.9% annually to 2026 by CONE area to calculate the representative firm gas capacity. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix A.

III.C.3. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. As discussed above, we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.

III.C.4. Escalation to 2026 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 8) have been used to escalate the O&M costs. The assumed real escalation rate for O&M line items that are primarily labor-based is 1.6% per year, while those for other O&M costs remain constant in real terms.

III.D. Financial Assumptions

III.D.1. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[16] Consistent with our approach in previous CONE studies, we developed our recommended cost of capital by an independent estimation of the ATWACC for publicly-traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from recent merger and acquisition transactions.[17] Based on our empirical analysis as of March 31, 2022, we recommend 8.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2026 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, cost of debt 4.7%, a combined federal and state tax rate of 27.7%, and return on equity (ROE) of 13.6%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and ROE do not significantly affect the CONE calculation as long as they amount to the empirically-based 8.0% ATWACC.[19] This is because the CONE value is determined by the 8.0% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

As a point of reference, we compare our current ATWACC recommendation to recommendations in our prior PJM CONE studies in Figure 7. The red circles (35% federal tax rate for 2011 and

[16] The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

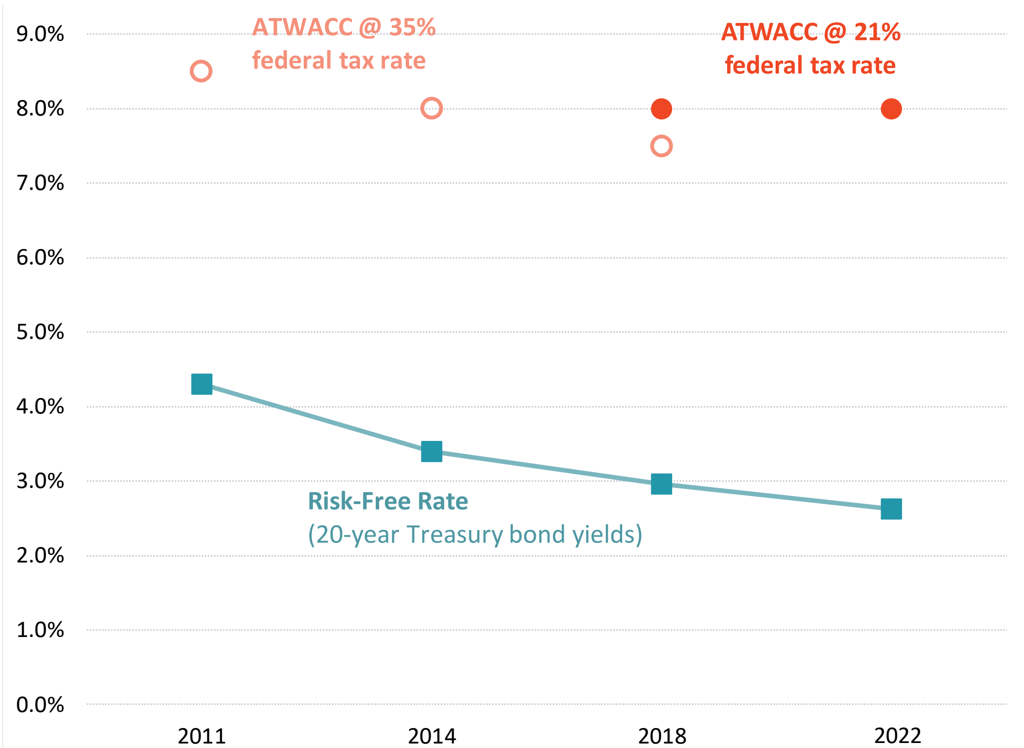
[17] Supplementing our ATWACC analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours.

[18] 4.7% × 55% × (1 – 27.7%) + 13.6% × 45% = 8.0%. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes (= 8.5% + (1 – 8.5%) × 21%). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

[19] Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

2014) and dots (21% tax rate for 2018 and 2022) represent the recommended ATWACCs, and the line is the prevailing risk-free rate (20-year Treasury rate).

FIGURE 7: COMPARISON OF BRATTLE ATWACC RECOMMENDATIONS FOR PJM



Sources: 2011, 2014, and 2018 values based on previous PJM CONE studies.

Over the last decade, our recommended ATWACC of merchant generation was 8.5% in 2011, then dropped and stayed at 8% between 2014 and 2022. These changes are driven by changes in both business risks of the industry, and market risks such as the risk-free rate and corporate income tax rates.

- We lowered the ATWACC from 8.5% to 8% in 2014 because the 20-year Treasury rate dropped from 4.3% in 2011 to 3.4% in 2014.
- The 20-year Treasury rate dropped further in 2018 to 3.0%. However, we kept our ATWACC recommendation at 8%, because the reduction in federal corporate income tax rate, from 35% to 21% starting from 2018, increases the ATWACC.
- The 20-year Treasury rate dropped again in 2022 to 2.6% as of March 2022. However, the top of the ATWACC range from the sample (the business risk of the merchant generation industry) and the additional reference points approximates 8.0% (Figure 8).

In Table 12, we compare our current recommended costs of capital components to those in our prior PJM CONE studies. The changes in the return of equity (ROE) are based on a number of factors: our recommended ATWACC, the federal-state combined tax rate, cost of debt, and the debt/equity ratios.

TABLE 12: COMPARISON OF COST OF CAPITAL RECOMMENDATIONS

Study Year	Tax Rate	Return on Equity	Equity Ratio	Cost of Debt	Debt Ratio	ATWACC
2011	40.5%	12.5%	50%	7.5%	50%	8.5%
2014	40.5%	13.8%	40%	7.0%	60%	8.0%
2018	27.7%	13.0%	45%	5.5%	55%	8.0%
2022	27.7%	**13.6%**	45%	**4.7%**	55%	8.0%

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for U.S. IPPs. Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[20] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

ATWACC for Publicly Traded Companies as of March 31, 2022: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 13 and charted with sensitivities in Figure 8. Base-case estimates are derived from three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 6.3% for AES to 7.6% for NRG. Additional details about the sample and key inputs are discussed next.

[20] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

TABLE 13: BASE-CASE ATWACC - 2022

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$15,862	$17,754	1.10	10.8%	41%	4.3%	6.3%
NRG Energy Inc	BB+	$9,179	$8,202	1.15	11.2%	53%	4.9%	7.6%
Vistra Corp	BB	$10,117	$10,515	1.10	10.8%	47%	5.2%	7.1%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 3/31/2022, millions USD.
[4]: Value Line.
[5]: RFR (2.62%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

Sample: Our sample consists of three companies: NRG, Vistra, and AES. Since 2018, there are no longer any pure-play merchant generation companies in the US. In 2018, Calpine was taken private by a consortium of private investors, and Dynegy was acquired by Vistra. The new Vistra includes both electricity generation and retail electricity supply. In addition, NRG expanded into competitive retail electricity supply. NRG and Vistra do not currently report their operating segments along the generation and retail supply lines of business. Their business mixes in terms of operating profits in 2019 are shown in Table 14.[21] Our sample also includes AES, a diversified global energy company holding assets in both utilities and the construction and generation of electricity. However, its annual financials only disclose its business segments by geography, not by line of business.[22]

TABLE 14: BUSINESS MIX OF NRG AND VISTRA IN 2019

Company [1]	Retail [2]	Generation [3]
NRG	38%	62%
Vistra	8%	92%

[21] NRG changed its segment reporting in 2020 such that the split between power generation and retail is not available.

[22] AES discloses its annual financials for each of its strategic business units: US and Utilities (which covers the United States, Puerto Rico and El Salvador); South America (which covers Chile, Colombia, Argentina and Brazil); MCAC (which covers Mexico, Central America and the Caribbean); and Eurasia (which covers Europe and Asia). Source: The AES Corporation. (December 31, 2019). Form 10-K. https://s26.q4cdn.com/697131027/files/doc_financials/2019/q4/2019-Form-10-K-FINAL.pdf.

Cost of Equity: We estimate the return on equity (ROE) of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 13, the resulting return on equity ranges from 10.8-11.2% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- We estimated the expected risk premium of the market to be 7.46% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[23]
- In Table 13, we use a risk-free rate of 2.62%, a 15-day average of 20-year U.S. treasuries as of March 31, 2022, as the base case. In addition to our base analysis under current market conditions, we also consider the use of forecasted risk-free rates applicable five years from now to estimate the offer of a new merchant entrant that starts operating in 2026. Blue Chip Economic Indicators forecasts a 3.0% yield for 10-year Treasury yields between 2023 and 2026.[24] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.5%, we estimate the 20-year risk-free rate to be 3.5% and use this as a sensitivity analysis, as shown in Figure 8 below.
- We use betas (column [4] in Table 13) reported by Value Line.[25] They are calculated using 2-year weekly returns.

Cost of Debt: In our previous analyses, we estimated the cost of debt (COD) of the sample companies by the average bond yields corresponding to the unsecured senior credit ratings for each company (issuer ratings).[26] The rating-based average yields, based on a sample of similarly-

[23] Kroll Cost of Capital Navigator 2021, as of February 2022 (arithmetic average of excess market returns over 20-year risk-free rate from 1926-2021).

[24] Blue Chip Economic Indicators (March 2022), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers.

[25] The 3-year period is chosen over the standard 5-year period to limit the period under the new tax law, which went into effect in 2018, and also to limit the period to be post integration of the 2017 Dynegy / Vistra merger and the spinoff of NRG Yield in 2018.

[26] In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

rated long-term (10 plus years) corporate bonds, are generally preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[27]

TABLE 15: COST OF DEBT

Company	S&P Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
AES Corp	BBB-	2.5%	4.3%
NRG Energy Inc	BB+	2.8%	4.9%
Vistra Corp	BB	3.1%	5.2%

However, company-specific CODs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate. This is the case for the merchant generation corporations: the average yields for the BBB-, BB+, and BB rated corporate bonds are barely higher than the current risk-free rate and lower than the Blue Chip forecast for the risk-free rate in 2022 and 2023. In contrast, U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the base-case estimation in Table 13, we use the company-specific bond yield, but in the sensitivity analysis (Figure 8 below) we also use rating-based cost of debt.

Debt/Equity Ratio: We estimate the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg. They are reported in Table 13 above.

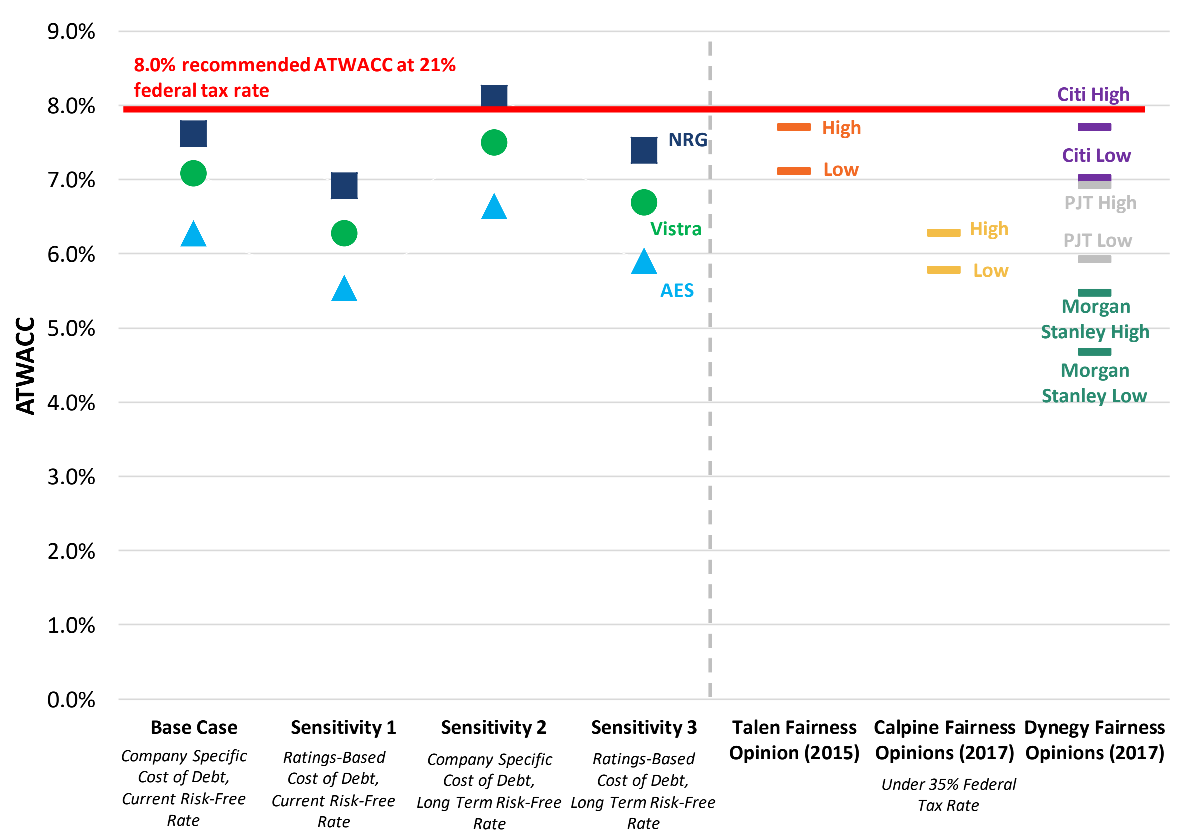
ATWACC Sensitivities and Cost of Capital Benchmarks from Recent Fairness Opinions:
Figure 8 reports the ATWACC for the sample under alternative assumptions for the COD and risk-free rate, along with the discount rates used in fairness opinions (discussed below) as additional reference points:

- *Baseline Case* uses the inputs and results shown in Table 13 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted long-term risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted long-term risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

[27] These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. By construction, these factors tend to be averaged out in the ratings-based average CODs.

For the Base Case and each sensitivity, the colored marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs range from 5.5% (AES) to 6.9% (NRG). Under the other two scenarios when the forecasted risk-free rate is used, the upper ends of the ATWACC approach 8.1% (Sensitivity 2) and 7.4% (Sensitivity 3).

FIGURE 8: SUMMARY OF BASE CASE AND ALTERNATIVE CASES



Additional cost of capital reference points shown on the right side of Figure 8 above come from publicly-available discount rates used by financial advisors and analysts in valuations associated with mergers and divestitures. While there are no details provided on how these ranges were developed, these values still provide useful reference points for estimating the cost of capital. As in our 2018 analysis, we rely on three transactions with publicly-disclosed discount rates, and adjust them for the changes in the risk-free rates between the as of dates of the fairness opinions and March 31, 2022. These three transactions are

- *Acquisition of Talen Energy by Riverstone Holdings*: the disclosed range of discount rate is 6.7% to 7.3%, released in June 2016.[28] Between the fairness opinion date (March 31, 2016)

[28] Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016.

and March 31, 2022, the risk-free rate increased about 0.4%. As a result, the range of 7.1% to 7.7% is shown in Figure 8.

- *Acquisition of Calpine by Energy Capital Partners*: the range of discount rate range disclosed in the June 2017 fairness opinion is 5.75% to 6.25%;[29] this is also the range shown in Figure 8, as the risk-free rates between June 2017 and March 31, 2022 are almost the same;
- *Acquisition of Dynegy by Vistra*: each of the three financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) involved in that transaction used a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citi.[30] This rather wide range of discount rates (4.7% to 7.7%) reflects the uncertainty in cost of capital estimates for the U.S. merchant generation industry. Because the risk-free rates between the fairness opinion dates and March 31, 2022 are almost the same, the originally disclosed range is shown in Figure 8.

We should note that all these acquisitions were announced before the 2018 tax law change, so their discount rates were based on the 35% federal corporate income tax rate. All else equal, the discount rate would be higher under a lower federal income tax rate. In other words, the ranges shown in Figure 8 under-estimates the ATWACC from the transactions under the current 21% tax rate.

ATWACC for Merchant Generators in PJM Markets and the Recommended Components: The appropriate ATWACC for the CONE study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As a pure merchant project in PJM, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts in place.[31] As we have done in previous studies, we make an upward adjustment toward the upper end of the range from the comparable company results to reflect the relatively higher risk of pure merchant operations. Based on the set of reference points shown in Figure 8 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation

[29] Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

[30] Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 25, 2018.

[31] This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

companies, we believe that an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[32]

III.D.2. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal tax rates of 21%. The state tax rates assumed for each CONE Area are shown in Table 16.

TABLE 16: STATE CORPORATE INCOME TAX RATES

CONE Area	Representative State	Corporate Income Tax Rate	Sales Tax Rate
1 Eastern MAAC	New Jersey	11.50%	0.00%
2 Southwest MAAC	Maryland	8.25%	0.00%
3 Rest of RTO	Pennsylvania	9.99%	0.00%
4 Western MAAC	Pennsylvania	9.99%	0.00%

Sources and notes: State tax rates retrieved from www.taxfoundation.org. Machinery and equipment for electricity generation are exempt from state sales taxes.

We calculated depreciation for the 2026/27 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2027 can apply 20% bonus depreciation in the first year of service, which decreases CC CONE on average by $10/MW-day relative to no bonus depreciation. The bonus depreciation phases out completely by the following year. Similar to the 2018 PJM CONE study, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for the reference CC to the remaining depreciable costs (*i.e.*, 20% bonus depreciation, 80% MACRS in 2026/27).[33]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of

[32] The weighted average cost of capital (WACC) without considering the tax advantage of debt payments is 8.0%. We report this value because it is comparable to values reported in other recently released CONE studies in ISO-NE and NYISO.

[33] Internal Revenue Service (2021), *Publication 946, How to Depreciate Property,* March 3, 2022. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 55% debt and 4.7% COD.

III.E. Economic Life and Levelization Approach

Translating investment costs into annualized costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life, such that the investor recovers capital and annual fixed costs.

For economic life, we recommend continuing the prior assumption of a 20-year economic life. Although new natural gas-fired plants can physically operate for 30 years or longer, developers in the stakeholder community expressed doubt in any value beyond 20 years in the current and projected policy environment. The policy environment is increasingly disfavoring generation resources that emit greenhouse gases. For example, Illinois and New Jersey have passed legislation or are considering regulations to limit the operation of natural gas-fired plants.[34]

We continue to assume "level-nominal" cost recovery with net revenues constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms), based on our prior analysis of the drivers of long-term cost recovery and updated analysis of the long-term trends in gas turbine costs. Clearly, assuming such a steady stream of revenues then terminating them after an assumed 20-year life is a simplification. Our concurrent VRR Report tests the robustness of the recommended VRR curve to an uncertainty range that encompasses different assumptions on cost recovery.

[34] In Illinois, the 2021 Climate and Equitable Jobs Act (CEJA) phases out of privately-owned gas generation by 2045. While the CEJA does not limit the ability of new CCs to enter, alternative ownership structures may be required with public entities to maintain operation over a 20-year economic life. In New Jersey, the Department of Environmental Protection proposed rules in 2021 that would limit CO_2 emissions for new gas generation units to below 860 lbs CO_2/MWh starting in 2025. Despite this proposed rule, the reference CC will be able to meet the emissions requirements.

III.F. CONE Results and Comparisons

III.F.1. Summary of CONE Estimates

The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 17 summarizes our plant capital costs, annual fixed costs, and levelized CONE estimates for the CC reference plants for the 2026/27 delivery year. The level-nominal CONE estimates range from $506/MW-day in WMAAC to $490/MW-day in SWMAAC.

TABLE 17: ESTIMATED CONE FOR CC PLANTS IN 2026/27

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

Sources and notes: CONE values expressed in 2026 dollars and ICAP terms.

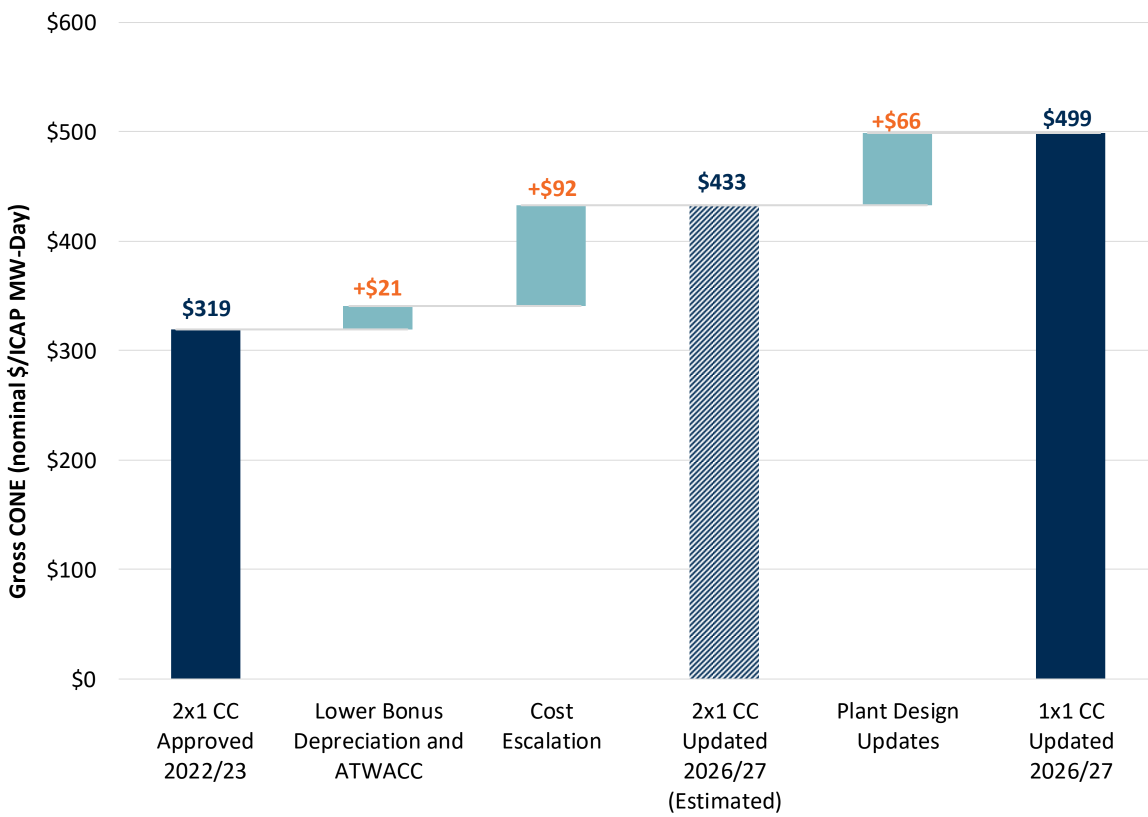
The CC CONE estimates vary slightly by CONE Area, primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

III.F.2. Comparison to Prior CONE Estimates

The 2026/27 CC CONE estimates are considerably higher than the values derived from the 2018 Study that were used (as MOPR parameters) in PJM's Base Residual Auction for the 2022/23

Delivery Year as shown in Figure 9. To explain those increases in terms of individual drivers, we sequentially estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, plant design updates.

FIGURE 9: DRIVERS OF HIGHER CC 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The temporary 100% bonus depreciation included in the 2022/23 CONE value decreases to 20% by 2026, increasing CONE by $25/MW-Day (ICAP).[35] The ATWACC decreased from 8.2% in the prior CONE value to 8.0% currently, decreasing CONE by $4/MW-Day (ICAP), for a net effect of $21/MW-Day (ICAP).
- Cost Escalation: Since the development of the 2022/23 CONE value in our 2018 Study (based on overnight costs of a plant built in 2017), the costs of materials, equipment, and labor costs have escalated along with generalized inflation at a faster rate than expected. For example, from December 2017 to December 2021, material costs increased by 36% compared to

[35] 115th United State Congress, "Tax Cuts and Jobs Act," Signed into law December 22, 2017

expectations of only 10%.[36] With that unexpected escalation over that time period, plus projected escalation to a 2026 installation, total cost escalation to 2026/27 adds $92/MW-Day (ICAP) to the 2x1 CC 2022/23 CONE value.

- Plant Design Updates: The use of dry-cooling ACCs, firm gas transportation contracts (and to a small degree the switch from a 2x2 CC to a double-train 1x1 CCs) as discussed in Section III.A above, adds $66/MW-Day (ICAP) to the 2x1 CC Updated 2026/27 (Estimated) CONE.

III.G. Annual CONE Updates

The PJM tariff specifies that prior to each auction PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review. The updates will account for changes in plant capital costs based on a composite of Department of Commerce's Bureau of Labor Statistic indices for labor, turbines, and materials.

We recommend that PJM continue to update the CONE value prior to each auction using this approach with slight adjustments to the index weightings based on the updated capital cost estimates. As shown in Table 18 below, we recommend that PJM re-weight the components to account for the increasing portion of total plant costs that are from the costs of labor. For the CC, PJM should calculate the composite index based on 40% labor, 45% materials, and 15% turbine. For the CT, PJM should calculate the composite index based on 30% labor, 45% materials, and 25% turbine.

TABLE 18: CONE ANNUAL UPDATE COMPOSITE INDEX

	Combustion Turbine			Combined Cycle		
Component	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index
Labor	20%	30%	30%	25%	43%	40%
Materials	50%	45%	45%	60%	45%	45%
Turbine	30%	25%	25%	15%	12%	15%

PJM will need to account for bonus depreciation declining from 20% for the 2026/2027 BRA to 0% in the 2027/2028 BRA and subsequent auctions. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 1.7% and the CC CONE by 2.1% due to the decreasing depreciation tax shield. We recommend just for the 2027/2028 BRA that after PJM

[36] Material and turbine costs increases are based on BLS Producer Price Index for *Construction Materials* and *Components for Construction* and *Turbines and Turbine Generator Sets* between December 2017 and December 2021. Values may not add to 100% due to rounding.

has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of no longer receiving bonus depreciation by applying an additional gross up of 1.017 for CT and 1.021 for CCs. For subsequent auctions, no further gross up will be necessary.

III.H. E&AS Offset Methodology

The VRR Curve prices are indexed to Net CONE, which is derived by subtracting the reference resource's net energy and ancillary service (E&AS) revenues from its Gross CONE. This E&AS offset could be estimated in a variety of ways. PJM originally estimated it based on actual historical electricity and natural gas prices over the past 3 years. In 2020, PJM adopted a forward-looking approach to calculating the E&AS offset based on forward prices for electricity and natural gas, with hourly shapes based on historical data. FERC subsequently ordered PJM in December 2021 to revert back to the historical method because the forward methodology had been implemented along with PJM's proposed Reserve Pricing Reforms that FERC eventually rejected.

We continue to recommend calculating E&AS on a forward basis over a historical approach. As discussed in our prior reviews, the forward E&AS offset is superior because it reflects expected market conditions that developers will face upon entry into the market. The methodology we helped PJM develop is analytically rigorous, based on forward market data for electricity and natural gas. It is similar to approaches we have implemented for clients and have seen other investors use to estimate their future net E&AS revenues (and, by extension, to estimate how much they would need to earn from the capacity market to enter). By contrast, the backward looking approach reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract (with a willingness-to-pay indexed to estimated Net CONE). Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather conditions that substantially distort the calculation and make it unduly volatile.[37]

However, both historical and forward methods rely on market prices that recently have reflected installed capacity well above the reserve requirement, which can perpetuate disequilibria. When supply is scarce, for example, the E&AS offset will increase and scale down the VRR curve thus

[37] For the same reasons, we recommend forward E&AS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, even if this is not implemented, we still recommend using a forward E&AS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected E&AS revenues.

buy less capacity just when it is needed. This could be avoided by adjusting the E&AS offset to what they would be at the target reserve margin, as NYISO and ISO-NE attempt to do. However, the need for an adjustment is not necessarily clear, without knowing what beliefs about reserve margins underlie forward market prices. Any equilibrium E&AS offset would rely on market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices.

Assuming PJM pursues a forward approach again, we reviewed several aspects of its approach and provide the following recommendation:

- Electric Hub Mapping: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices;
- Natural Gas Hub Mapping: Switch EKPC gas hub from Columbia-App TCO to MichCon; otherwise current gas hub mapping supported by recent prices;
- Ancillary Service Prices: Remove regulation revenues from the calculation of the E&AS offset and scale historical hourly sync and non-sync reserve prices by forward energy prices.

Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate.

PJM also requested that we review the approach for calculating the energy efficiency wholesale energy savings to determine whether the utility EE programs included in the analysis continue to be reasonable. Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts. The current sample includes the largest utilities in each state that provides sufficient detail for the analysis. Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample.

III.I. Implications for Net CONE

III.I.1. Indicative E&AS Offsets

The application of the E&AS offset methodology in Section III.H results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, removal of regulation revenue, and updates to other operating characteristics associated with the technical specifications for the CC.[38] Table 19 shows the effect of each of these changes on the forward-looking 2023/24 E&AS revenue offset by zone for the CC based on simulations provided by PJM staff.

[38] Other parameter updates include updated operating characteristics associated with the most recent turbine models, the addition of dry-cooling, and the 1x1 single shaft CC configuration.

TABLE 19: UPDATED 2023/24 CC E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	CC			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$168	$2	-$24	$146
DPL	$216	$3	-$23	$196
JCPL	$166	$2	-$24	$143
PECO	$184	$14	-$23	$174
PSEG	$162	$2	-$24	$140
RECO	$172	$2	-$23	$151
CONE Area 2				
BGE	$254	$4	-$20	$239
PEPCO	$197	$10	-$21	$185
CONE Area 4				
METED	$212	$15	-$22	$205
PENELEC	$320	$7	-$17	$310
PPL	$190	$15	-$22	$182
CONE Area 3				
AEP	$242	$8	-$21	$229
APS	$281	$5	-$19	$267
ATSI	$208	$44	-$21	$231
COMED	$179	$11	-$22	$168
DAY	$223	$45	-$21	$247
DEOK	$214	$43	-$21	$237
DUQ	$225	$15	-$20	$219
DOM	$195	$9	-$21	$183
EKPC	$246	$14	-$21	$239
RTO	**$189**	**$11**	**-$23**	**$177**

Note: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020. The "Updated 2023/24 EAS" values do not reflect changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

III.I.2. Indicative Net CONE

Net CONE is the estimated annualized fixed costs of new entry, or Gross CONE, of the reference resource, net of estimated E&AS margins and expected performance bonus. PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE. We present in Table 20 below indicative CC Net CONE estimates for all LDAs relative to the parameters used in the 2022/23 MOPR (adjusted here to differentiate CONE values by area).

We say "indicative" because the scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach, but does not include estimating the E&AS offsets for the 2026/27 BRA.

TABLE 20: INDICATIVE CC NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	CC 2022/23 MOPR			CC 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$335	$167	$163	$517	$174	$343
DPL	$335	$208	$122	$517	$231	$286
JCPL	$335	$165	$165	$517	$172	$346
PECO	$335	$186	$144	$517	$206	$311
PSEG	$335	$161	$169	$517	$168	$349
RECO	$335	$171	$159	$517	$180	$337
EMAAC	**$335**	**$181**	**$154**	**$517**	**$189**	**$329**
CONE Area 2						
BGE	$345	$254	$76	$506	$279	$227
PEPCO	$345	$191	$139	$506	$219	$287
SWMAAC	**$345**	**$238**	**$107**	**$506**	**$249**	**$257**
CONE Area 4						
METED	$323	$207	$123	$522	$241	$281
PENELEC	$323	$306	$24	$522	$359	$163
PPL	$323	$185	$145	$522	$216	$307
MAAC	**$334**	**$204**	**$130**	**$517**	**$222**	**$294**
CONE Area 3						
AEP	$316	$233	$97	$518	$268	$251
APS	$316	$272	$58	$518	$311	$208
ATSI	$316	$224	$106	$518	$271	$248
COMED	$316	$195	$135	$518	$199	$319
DAY	$316	$235	$95	$518	$288	$230
DEOK	$316	$224	$106	$518	$277	$242
DUQ	$316	$223	$107	$518	$257	$261
DOM	$316	$181	$149	$518	$216	$303
EKPC	$316	$232	$98	$518	$279	$239
OVEC	$316	$260	$70	$518	$303	$216
RTO	**$330**	**$185**	**$146**	**$516**	**$209**	**$307**

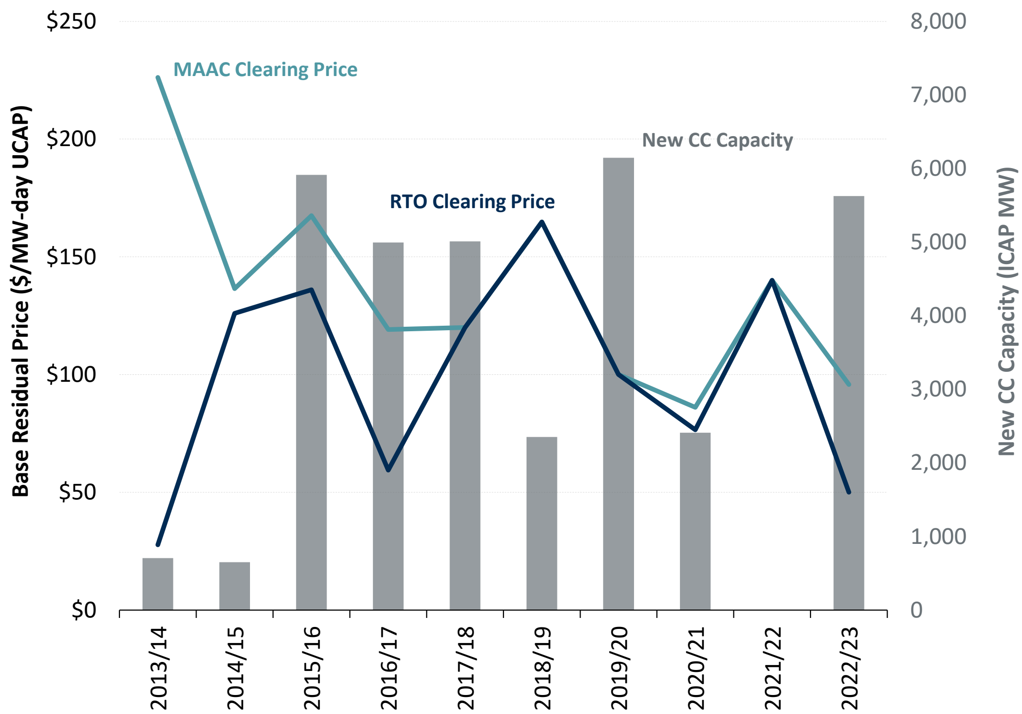
Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

Net CONE is $257–$329/MW-Day (UCAP) across all parent LDAs. Compared to the 2022/23 BRA, the Net CONE roughly doubled for all parent LDAs. Increases in Net CONE are due to the increases in Gross CONE described in Section III.F (cost escalation, decreases in bonus depreciation, and plant design changes) with a slight offset from higher E&AS values. The differences among modeled LDAs and the RTO are similar to the prior.

III.I.3. Comparison to "Empirical Net CONE"

Another informative comparison is to the prices at which actual CCs have been willing to enter the market in past capacity auctions (sometimes referred to as "empirical Net CONE"). Those prices ranged from $75 to $165/MW-Day UCAP in most of the recent auctions, as shown in Figure 10 below. Note that 2022/23 prices should be disregarded as an indicator of willingness to enter since the compressed forward period for that auction meant that new entrants' decisions were already made by the time the auction occurred.

FIGURE 10: HISTORICAL BRA CAPACITY PRICES AND NEW CC CAPACITY



Sources and notes: PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2013/14-2022/23. Please note that the 2022/23 BRA was a compressed auction.

Empirical Net CONE is not a perfect indicator of "true Net CONE" at which capacity could enter at scale—even at the time that capacity entered—because of variability across locations, limited entry in any single auction, and observing only a single clearing price. Some entrants would have entered at prices below the clearing price, whereas uncleared projects, which might have been needed if more retirements or load growth had occurred, would require a higher price. Some may be willing to enter the market at low prices because of their idiosyncratic advantages that cannot be replicated at scale. For example, some past entrants may have enjoyed special opportunities to access natural gas at anomalously low costs earlier in the development of the

Marcellus Shale and export pipelines. Despite these limitations, empirical Net CONE is still a useful benchmark.

Extrapolating backward-looking empirical Net CONE to the future, however, must consider how costs and market conditions have changed. As discussed above, the true cost of entry is in fact increasing due to cost escalation, changes in environmental regulations and plant configurations, and tax laws—by $180/MW-day in our estimation compared to a few years ago. In addition, since the long-term prospects for cash flows have diminished with the industry's transition toward clean energy, entrants may need to front-load their revenues more so than in the past. For example, if they used to assume a 30-year economic life but now assume 20 years, that would further increase Net CONE by $44/MW-day ICAP. Altogether, adding that $180 + $44 to historical empirical Net CONE of $100-165/MW-day, suggests an adjusted benchmark for 2026 of as much as $324-389/MW-day, or $280-345 MW-day without the adjustment for economic life. This is not far from our estimated Net CONE of $257-$329/MW-day across modeled LDAs.

III.I.4. Uncertainty Analysis

There is considerable uncertainty in estimating Net CONE. Most of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, or more if technologies are more constrained by environmental regulations. These examples indicate an uncertainty range on Net CONE of -29% to +16%; the full uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we recommend testing robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

IV. Natural Gas-Fired Combustion Turbines

IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 60HZ
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	361 / 363 / 353 / 350*
Net Heat Rate (HHV in Btu/kWh)	9320 / 9317 / 9304 / 9311*
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 installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011

Turbine Model	Turbine Class	PJM		US	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric LM6000	Aeroderivative	7	331	69	3,101
General Electric 7FA	Frame	2	330	14	2,462
Pratt & Whitney FT4000	Aeroderivative	2	120	2	120
Rolls Royce Corp Trent 60	Aeroderivative	2	119	2	119
Pratt & Whitney FT8	Aeroderivative	1	57	4	189
Siemens Unknown	N.A.	1	28	2	545
General Electric LMS100	Aeroderivative	0	0	47	4,664
Siemens SGT6-5000F	Frame	0	0	10	1,892
Rolls Royce Corp Unknown	N.A.	0	0	10	599
General Electric 7EA	Small Frame	0	0	7	417
Siemens AG SGT	Frame	0	0	7	401
General Electric 7HA	Frame	0	0	1	330
All Other Turbine Models		0	0	14	1,297
Total		**15**	**985**	**189**	**16,136**

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that the Perryman Unit 6 CT plant built in 2015 in Maryland included in its operating permit to avoid exceeding emissions thresholds.[39]

- Land: Similar to the reference CC, we estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 10 acres of land are for the reference CT.

TABLE 23: COST OF LAND PURCHASED FOR REFERENCE CT

CONE Area	Land Price *($/acre)*	Plot Size Gas CT *(acres)*	Cost Gas CT *($m)*
1 EMAAC	$36,600	10	$0.37
2 SWMAAC	$29,500	10	$0.30
3 Rest of RTO	$16,400	10	$0.16
4 WMAAC	$30,600	10	$0.31

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

Based on the technical specifications for the CT described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 24 below.

[39] The Perryman Unit 6 operating permit is available here: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Test/Constellation%20Perryman%20Renewal%20Title%20V%202018.pdf

TABLE 24: PLANT CAPITAL COSTS FOR CT REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*361 MW*	*363 MW*	*353 MW*	*350 MW*
Owner Furnished Equipment				
Gas Turbines	$78.6	$78.6	$78.6	$78.6
HRSG / SCR	$33.5	$33.5	$33.5	$33.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$112.1**	**$112.1**	**$112.1**	**$112.1**
EPC Costs				
Equipment				
Other Equipment	$24.1	$24.1	$24.1	$24.1
Construction Labor	$50.6	$37.8	$40.6	$45.0
Other Labor	$16.4	$15.4	$15.6	$16.0
Materials	$8.1	$8.1	$8.1	$8.1
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$21.1	$19.8	$20.1	$20.5
EPC Contingency	$23.2	$21.7	$22.1	$22.6
Total EPC Costs	**$143.6**	**$127.0**	**$130.6**	**$136.3**
Non-EPC Costs				
Project Development	$12.8	$12.0	$12.1	$12.4
Mobilization and Start-Up	$2.6	$2.4	$2.4	$2.5
Net Start-Up Fuel Costs	-$0.6	-$0.6	$0.1	-$0.5
Electrical Interconnection	$7.8	$7.8	$7.6	$7.6
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$0.4	$0.3	$0.2	$0.3
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$1.3	$1.2	$1.2	$1.2
Owner's Contingency	$4.6	$4.6	$4.6	$4.6
Emission Reduction Credit	$0.0	$0.0	$0.0	$0.0
Financing Fees	$7.0	$6.6	$6.7	$6.8
Total Non-EPC Costs	**$69.6**	**$68.0**	**$68.7**	**$68.6**
Total Capital Costs	**$325.3**	**$307.1**	**$311.4**	**$317.0**
Overnight Capital Costs ($million)	**$325**	**$307**	**$311**	**$317**
Overnight Capital Costs ($/kW)	**$902**	**$846**	**$882**	**$906**
Installed Cost ($/kW)	**$945**	**$887**	**$925**	**$949**

IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in “$/factored start” and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

TABLE 25: O&M COSTS FOR CT REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *361 MW*	2 SWMAAC *363 MW*	3 Rest of RTO *353 MW*	4 WMAAC *350 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.3	$0.3	$0.3	$0.3
Labor	$1.2	$1.2	$0.9	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.3	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$2.2	$0.3
Insurance	$2.0	$1.8	$1.9	$1.9
Firm Gas Contract	$4.4	$5.4	$7.1	$6.3
Working Capital	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2026$ million)	**$9.5**	**$14.4**	**$13.5**	**$10.9**
Levelized Fixed O&M (2026$/MW-yr)	**$26,300**	**$39,600**	**$38,300**	**$31,300**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	1.19	1.18	1.15	1.22
Total Variable O&M (2026$/MWh)	**1.19**	**1.18**	**1.15**	**1.22**
Major Maintenance - Starts Based ($/factored start, per turbine)	**21,170**	**21,170**	**21,170**	**21,170**

IV.D.CONE Results and Comparisons

Table 26 shows plant capital costs, annual fixed costs, and levelized CONE estimates for the CT reference plant for the 2026/27 delivery year. CONE estimates range from $378/MW-day in EMAAC to $403/MW-day in the Rest of RTO. Note that we assumed accelerated tax depreciation based on the 15-year MACRS for the CT to the depreciable costs after accounting for bonus depreciation.

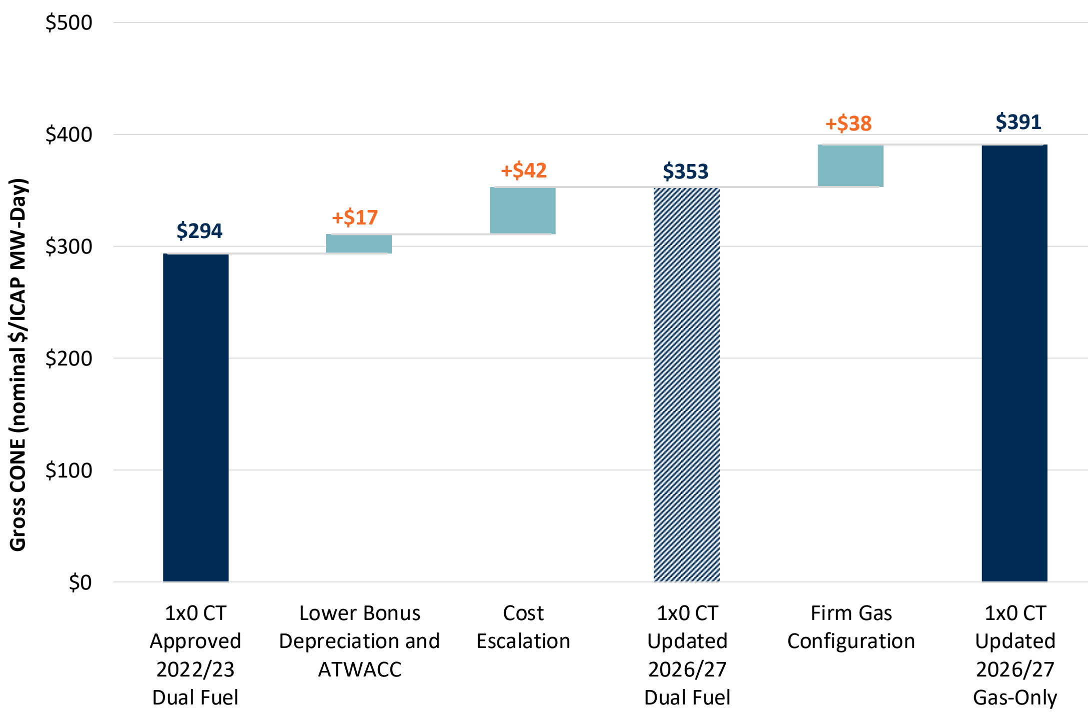
TABLE 26: ESTIMATED CONE FOR CT PLANTS FOR 2026/27 IN 2026$ AND ICAP MW

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$325	$307	$311	$317
[2]	Installed (inc. IDC)	*$m*		$341	$322	$326	$332
[3]	First Year FOM	*$m/yr*		$9	$14	$14	$11
[4]	**Net Summer ICAP**	***MW***		**361**	**363**	**353**	**350**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$902	$846	$882	$906
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$945	$887	$925	$949
[7]	Levelized FOM	*$/kW-yr*		$33	$44	$45	$39
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		11.7%	11.6%	11.6%	11.6%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$138,000**	**$141,700**	**$147,100**	**$144,000**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$378**	**$388**	**$403**	**$395**

Similar to the CC, the CT CONE estimates vary by CONE Area primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

The 2026/27 CT CONE estimates are considerably higher than in PJM's Base Residual Auction for the 2022/23 Delivery Year as shown in Figure 11. Similar to the presentation of CC CONE drivers, the attribution of changes to each element depends on the order in which the changes are implemented in our model. We estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, firm gas configuration.

FIGURE 11: DRIVERS OF HIGHER CT 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The decline to 20% bonus depreciation by 2026 increases CONE by $21/MW-day (ICAP). The ATWACC decreased to 8.0%, decreasing CONE by $4/MW-day (ICAP), for a net effect of $17/MW-Day (ICAP).
- Cost Escalation: Cost escalation is lower relative to the CC due to a lower portion of materials and labor costs associated with the CT. As a result, the total cost escalation to 2026/27 adds $42/MW-Day (ICAP) to the 1x0 CT 2022/23 Dual Fuel CONE value.
- Firm Gas Configuration: The use of firm gas transportation contracts, adds $38/MW-Day (ICAP) to the 1x0 CT Updated Dual Fuel 2026/27 CONE.

IV.E. Implications for Net CONE

IV.E.1. Indicative E&AS Offsets

The E&AS offset methodology described for CCs would also apply to CTs, but recognizing two differences related to CTs' operation as peaking plants that are generally committed day-of. As peaking plants, their dispatch depends more on the hourly volatility of prices that cannot be observed directly in forward markets and are instead taken from historical hourly price shapes. Since historical prices do not fully reflect future conditions, the E&AS offset estimates for CTs may be subject to more uncertainty than for CCs (at least on a percentage basis). This observation does not lead to an obvious recommendation for improving the E&AS offset methodology for CTs but does contribute to our assessment of uncertainty in selecting a suitable reference resource, as discussed above.

The fact that CTs are generally committed day-of does require a slight adjustment to fuel cost inputs in the E&AS offset calculation. As we noted in our 2018 Study, "PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM's Operating Agreement to the variable operating costs of the CTs in the simulations."[41] This time, we are not recommending a "10% adder" that FERC has recently rejected but, more precisely a 10% increase over (day-ahead) gas daily index prices (and no adder on CT VOM costs). This should provide reasonable and necessary adjustment to get more accurate fuel cost inputs.

The application of the CT E&AS offset methodology discussed above results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, then removal of regulation revenue. Table 27 shows the 2023/24 E&AS revenue offset by zone using the updated methodology.

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[41] 2018 VRR Curve Study, pp. 23-24.

TABLE 27: UPDATED 2023/24 CT E&AS REVENUE OFFSET BY ZONE

All values in nominal $/MW-day ICAP	CT			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$45	-$4	-$8	$33
DPL	$76	-$2	-$8	$65
JCPL	$43	-$4	-$8	$32
PECO	$48	$4	-$7	$45
PSEG	$41	-$4	-$8	$30
RECO	$48	-$3	-$8	$36
CONE Area 2				
BGE	$93	$6	-$9	$89
PEPCO	$57	-$1	-$7	$49
CONE Area 4				
METED	$65	$8	-$8	$65
PENELEC	$150	$28	-$12	$166
PPL	$52	$5	-$7	$49
CONE Area 3				
AEP	$83	$9	-$12	$79
APS	$114	$17	-$13	$118
ATSI	$66	$16	-$8	$75
COMED	$47	-$6	-$7	$34
DAY	$70	$21	-$8	$83
DEOK	$74	$17	-$8	$83
DUQ	$81	$15	-$8	$89
DOM	$56	-$1	-$7	$48
EKPC	$80	$11	-$10	$81
RTO	**$48**	**-$1**	**-$8**	**$39**

Sources and notes: The “Current 2023/24 E&AS” reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020, including a 10% adder on all variable costs. The “Updated 2023/24 EAS” values do not reflect recommended changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC’s zone.

IV.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the Net CONE shown for the reference CC. Table 28 shows the indicative CT Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 28: INDICATIVE 2026/27 CT NET CONE

All values in nominal $/MW-day UCAP	CT 2022/23 BRA			CT 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$312	$47	$265	$397	$48	$349
DPL	$312	$76	$236	$397	$85	$312
JCPL	$312	$45	$267	$397	$47	$351
PECO	$312	$54	$258	$397	$62	$336
PSEG	$312	$43	$268	$397	$44	$353
RECO	$312	$50	$262	$397	$52	$346
EMAAC	**$312**	**$52**	**$259**	**$397**	**$56**	**$341**
CONE Area 2						
BGE	$317	$90	$226	$408	$113	$315
PEPCO	$317	$57	$260	$408	$67	$315
SWMAAC	**$317**	**$74**	**$243**	**$408**	**$93**	**$315**
CONE Area 4						
METED	$305	$67	$238	$415	$85	$315
PENELEC	$305	$139	$166	$415	$200	$210
PPL	$305	$54	$250	$415	$67	$315
MAAC	**$311**	**$66**	**$245**	**$404**	**$79**	**$320**
CONE Area 3						
AEP	$305	$77	$227	$424	$101	$315
APS	$305	$102	$203	$424	$146	$315
ATSI	$305	$74	$230	$424	$96	$315
COMED	$305	$57	$248	$424	$49	$421
DAY	$305	$78	$226	$424	$105	$315
DEOK	$305	$81	$224	$424	$106	$315
DUQ	$305	$80	$224	$424	$112	$315
DOM	$305	$54	$250	$424	$65	$315
EKPC	$305	$76	$229	$424	$103	$315
OVEC	$305	$89	$216	$424	$130	$315
RTO	**$309**	**$49**	**$260**	**$411**	**$55**	**$356**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

V. Battery Energy Storage Systems (BESS)

During the stakeholder process, several stakeholders raised concerns about whether natural-gas-fired resources (either CCs or CTs) will be feasible to build in certain zones due to state policies that require a decreasing portion of the generation mix to come from GHG-emitting resources. Based on this input, we reviewed several non-emitting resources to include as possible reference resources and determined that the 4-hour BESS best meets the reference resource screening criteria described in Section II above.

While 4-hour BESS is currently not recommended as the reference resource in any zone, its CONE value provides an initial estimate for PJM and its stakeholders a starting point for future reviews or before then if the recommended reference resource, the gas-fired CC, is determined to be infeasible to be built within the Quadrennial Review period.

V.A. Technical Specifications

We developed the cost estimates for the 4-hour BESS based on the specifications listed in Table 29 below. We assumed the facility is sized for 200 MW at the point of interconnection, based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

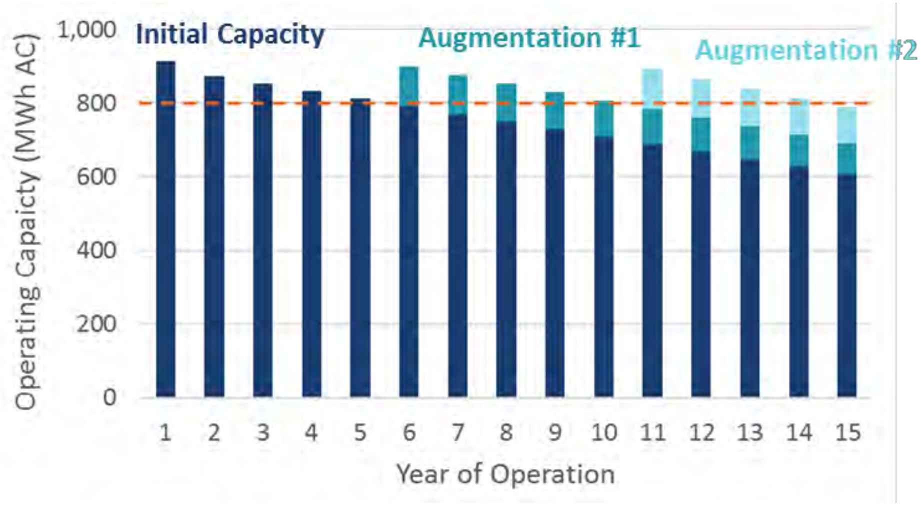
TABLE 29: BESS TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Chemistry	Lithium-ion
Installation Configuration	Containerized
Rated Output Power (at POI)	200 MW-ac
Duration	4 Hours
Installed Energy Capacity	1,030 MWh-dc
Annual Capacity Degradation	4% in Year 1, then 2% per year
Augmentations	Year 5 and Year 10
Use Case	Daily Cycling
Round Trip Efficiency	85%
Economic Life	15 Years
Salvage Value	$0

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4% in the first year and 2% in subsequent years, assuming daily cycling and a 5% minimum state of charge.[42] Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations that reduces the initial capital costs of the facility and may allow the owner to take advantage of declining module costs, depending on future cost trends. To account for degradation of the energy capacity, our cost estimate assumes that the facility will include an initial 13% overbuild, or 135 MWh-dc, with augmentations planned for Year 5 and Year 10. This is currently a common approach developers are taking, based on S&L's recent project experience, to reduce mobilization costs of frequent augmentation while still taking advantage of future costs declines.

42 Degradation occurs due to many factors, including time, ambient conditions, state-of-charge, operational profiles, depth of discharge and manufacturing defects.

FIGURE 12: BESS EENRGY CAPCITY OVER 15 YEAR LIFE



Accounting for the assumed overbuild, minimum state of charge, and on-site losses, the total installed energy capacity is 1,030 MWh-dc, accounting for AC and inverter losses of 6.2%.[43]

TABLE 30: BESS SIZING ASSUMPTIONS

Component	Value
Rated AC Output Power (at POI)	**200 MW-ac**
AC Losses	4.6%
Inverter Losses	1.6%
Gross DC Power Output	**212 MW-dc**
Minimum State of Charge	5.0%
Duration	4 hours
Gross Energy Capacity	**895 MWh-dc**
Overbuild due to Degradation	13%, or 135 MWh-dc
Installed Energy Capacity	**1,030 MWh-dc**

Note: Gross Energy Capacity represents the required capacity to achieve nameplate rated output power on the first day of operation

[43] AC losses include power control system and generator step-up transformer losses, line losses, and auxiliary load.

V.B. Capital Costs

As explained in more detail below, we estimated the 4-hour BESS CONE value using a top-down cost estimating approach that involves less detailed specification of the resource and its location for developing cost estimates. S&L estimated the EPC costs based on recent project data, establishing unitized costs for project components and scaling to the selected reference technology specifications with adjustments to account for labor rates in each CONE Area. S&L then verified the total installed costs against publicly available cost estimates for similar BESS resources.

We estimated the non-EPC costs using similar assumptions as the CC and CT for the per-kW costs of electrical interconnection and per-acre land costs. The remaining non-EPC costs components are estimated based on a percentage of total EPC with the same assumption as the CC and CT for project development, mobilization and start-up, and financing fees. We assumed a lower Owner's Contingency of 5% of BESS equipment costs instead of 8% for the CC and CT based on the larger share of costs covered by the EPC contract.

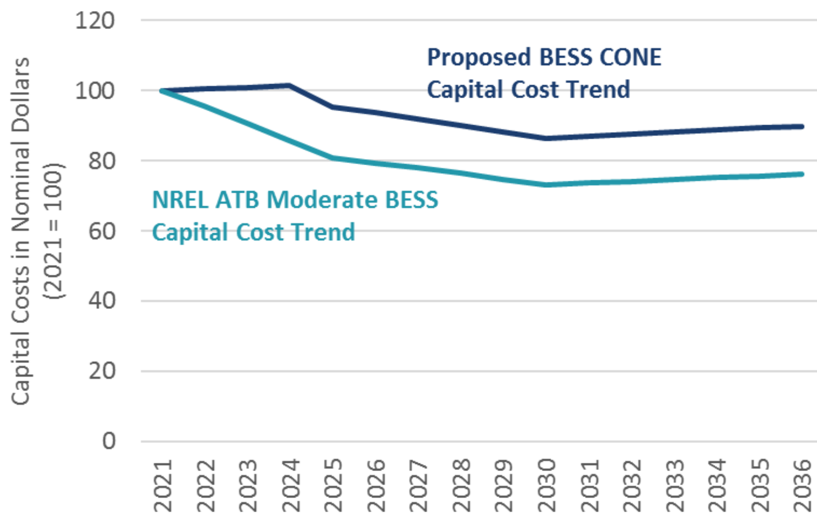
Based on the technical specifications for the reference BESS described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 31 below. EPC costs are primarily driven by the costs of the batteries and enclosures, which is currently estimated to be about $190/kWh-dc (in 2021 dollars). The EPC Contractor Fee and Contingency costs are assumed to be incorporated into the other BESS EPC costs.

TABLE 31: PLANT CAPITAL COSTS FOR BESS REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*200 MW*	*200 MW*	*200 MW*	*200 MW*
EPC Costs				
BESS Equipment				
Batteries and Enclosures	$193.5	$193.5	$193.5	$193.5
PCS and BOP Equipment	$29.0	$29.0	$29.0	$29.0
Project Management	$11.8	$9.4	$10.0	$10.8
Construction & Materials	$58.7	$46.9	$49.6	$53.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	Included	Included	Included	Included
EPC Contingency	Included	Included	Included	Included
Total EPC Costs	**$293.0**	**$278.8**	**$282.0**	**$286.9**
Non-EPC Costs				
Project Development	$14.7	$13.9	$14.1	$14.3
Mobilization and Start-Up	$2.9	$2.8	$2.8	$2.9
Owner's Contingency	$11.1	$11.1	$11.1	$11.1
Electrical Interconnection	$4.1	$4.1	$4.1	$4.1
Land	$0.4	$0.3	$0.2	$0.4
Working Capital	$0.0	$0.0	$0.0	$0.0
Financing Fees	$1.3	$1.3	$1.3	$1.3
Total Non-EPC Costs	**$34.6**	**$33.6**	**$33.6**	**$34.1**
Total Capital Costs	**$327.6**	**$312.4**	**$315.7**	**$321.0**
Overnight Capital Costs ($million)	**$328**	**$312**	**$316**	**$321**
Overnight Capital Costs ($/kW)	**$1,638**	**$1,562**	**$1,578**	**$1,605**
Installed Capital Costs ($/kW)	**$1,725**	**$1,646**	**$1,663**	**$1,691**
Installed Capital Costs ($/kWh)	**$409**	**$390**	**$395**	**$401**

Similar to the CC and CT, all equipment and material costs are initially estimated by S&L in 2021 dollars and escalated to the construction period for an online date of June 1, 2026 based on a 16-month construction drawdown schedule for BESS resources. We estimate the overnight capital cost for the BESS incurred during the construction period, as shown in Figure 13 below. S&L estimates that costs will decline in real terms by -1.5% per year from 2021 to 2024 (or +1.4% per year in nominal terms, given assumed inflation of 2.9% per year), based on contract data, trends, and expectations expressed by suppliers for projects currently in development. From 2024 to 2026, we then assume costs will decline in nominal terms based on the 2021 NREL Annual Technology Baseline Moderate cost projections. We use this approach as well for estimating augmentation costs in 2031 (Year 5) and 2036 (Year 10).

FIGURE 13: PROJECTED BESS CAPITAL COST TRENDS



V.C. Operation and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. Table 9 summarizes the annual fixed O&M costs, variable O&M costs, and augmentation costs in Year 5 and Year 10 for BESS with an online date of June 1, 2026. The annual O&M costs primarily include the fixed costs of the O&M contract for the facility and the costs of operating insurance.

As shown in Figure 12 above, the BESS storage capacity will fall below 800 MWh-ac in Year 6 based on the assumed initial overbuild and degradation rates. To maintain its 4-hour duration at 200 MW of output power through the economic life of the asset, we assume the developer will add 124 MWh-dc of additional battery modules in Year 5 at a cost of $30.5 million (in 2031 dollars) and another 124 MWh-dc of capacity in Year 10 at $33.1 million (in 2036 dollars).[44]

[44] Augmentation costs reflect the current estimate of module of $190/kWh plus a 20% markup for mobilization and installation costs and the projected trend in module costs shown in Figure 13.

TABLE 32: O&M COSTS FOR BESS REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *200 MW*	2 SWMAAC *200 MW*	3 Rest of RTO *200 MW*	4 WMAAC *200 MW*
Fixed O&M Components				
O&M Contract Fixed Payments	$2.7	$2.7	$2.7	$2.7
BOP and Substation O&M	$0.1	$0.1	$0.1	$0.1
Station Load / Aux Load	$0.4	$0.3	$0.3	$0.4
Miscellaneous Owner Costs	$0.3	$0.2	$0.3	$0.3
Operating Insurance	$1.3	$1.2	$1.3	$1.3
Land Lease or Property Taxes	$2.3	$4.4	$2.1	$2.0
Fixed O&M (2026$ million)	**$7.1**	**$9.0**	**$6.7**	**$6.7**
Fixed O&M ($/kW-yr)	**$35.3**	**$44.8**	**$33.6**	**$33.7**
Augmentation				
Year 5 Costs (2031$ million)	**$30.5**	**$30.5**	**$30.5**	**$30.5**
Year 10 Costs (2036$ million)	**$33.1**	**$33.1**	**$33.1**	**$33.1**
Levelized Augmentation Costs ($/kW-yr)	**$22.3**	**$22.3**	**$22.3**	**$22.3**
Total Levelized Fixed Costs ($/kW-yr)	**$57.7**	**$67.1**	**$55.9**	**$56.1**

The total levelized fixed O&M costs represent the total contribution of these costs to the CONE value, including both the annual fixed costs ($23/kW-year to $42/kW-year) and the levelized costs of the two capacity augmentations (about $28/kW-year). While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. All O&M and augmentation costs for the BESS are accounted for in Table 32 and the variable O&M costs are assumed to be $0.

V.D. CONE Estimates

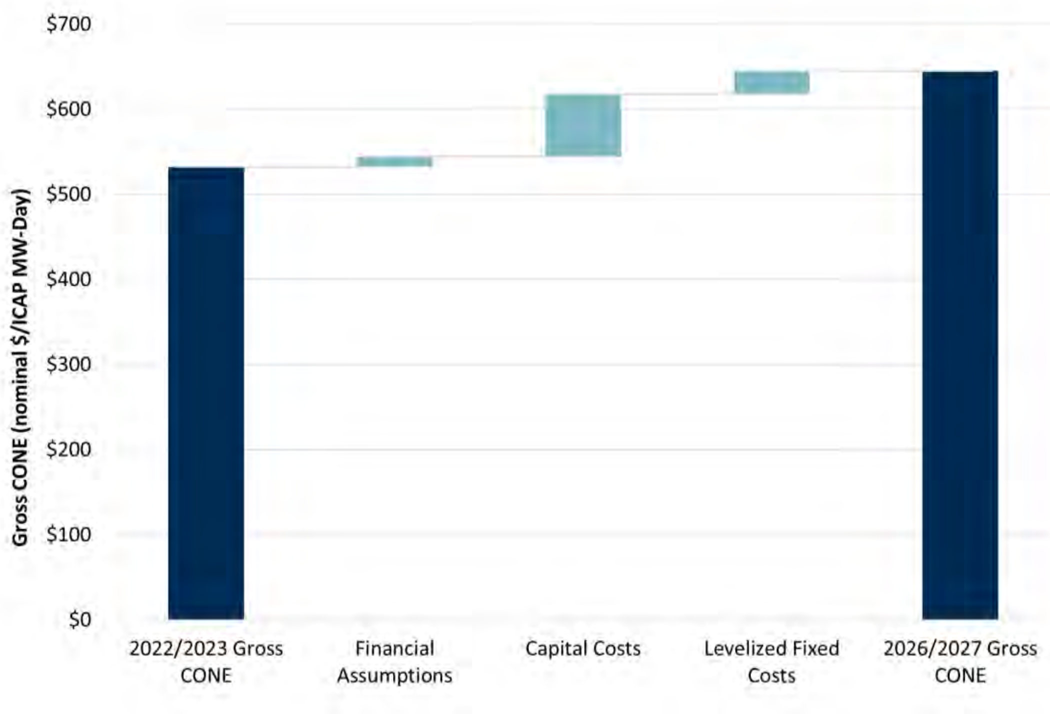
The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 33 summarizes plant capital costs, annual fixed costs, and levelized CONE estimates for the BESS reference resource for the 2026/27 delivery year. The CONE estimates range from $653/MW-day in Rest of RTO to $678/MW-day in EMAAC.

TABLE 33: ESTIMATED CONE FOR BESS FOR 2026/27 IN 2026$ AND ICAP MW

			4-Hour Battery Storage			
			EMAAC	SWMAAC	Rest of RTO	WMAAC
	Net Summer ICAP	*MW*	**200**	**200**	**200**	**200**
	Gross Costs					
[1]	Overnight	*$m*	$328	$312	$316	$321
[2]	Installed (inc. IDC)	*$m*	$345	$329	$333	$338
[3]	First Year FOM	*$m/yr*	$7	$9	$7	$7
[4]	Year 5 Augmentation	*$m*	$31	$31	$31	$31
[5]	Year 10 Augmentation	*$m*	$33	$33	$33	$33
	Unitized Costs					
[7]	Overnight	*$/kW*	$1,638	$1,562	$1,578	$1,605
[8]	Installed (inc. IDC)	*$/kW*	$1,725	$1,646	$1,663	$1,691
[9]	Levelized Fixed Costs	*$/kW-yr*	$66	$69	$64	$64
[10]	**After-Tax WACC**	*%*	**7.9%**	**8.0%**	**8.0%**	**8.0%**
[11]	Effective Charge Rate	*%*	11.1%	11.0%	11.1%	11.1%
[12]	**Updated CONE**	***$/MW-yr***	**$247,400**	**$240,900**	**$238,400**	**$241,500**
[13]	**Updated CONE**	***$/MW-day***	**$678**	**$660**	**$653**	**$662**

Similar to the CC and CT, the 2026/27 BESS CONE estimates are considerably higher than PJM's estimated CONE for the 2022/23 Delivery Year Base Residual Auction, as shown in Figure 14. PJM estimated the 2022/23 CONE based on cost estimates from the NREL Annual Technology Baseline. As described above, the updated estimates for the 2026/27 auction reflect more detailed specifications for a 200 MW facility in the PJM market and recent cost estimates based on actual projects currently under development, including recent cost escalation. As shown in Figure 13 above, the current outlook for BESS capital costs are about 15% higher than those projected by NREL in its latest ATB. The higher capital costs also reflect the assumed overbuild of capacity to account for degradation, whereas NREL assumed no overbuild and annual augmentation. The higher O&M costs reflect the recent costs of maintenance contracts as well as a more up-to-date outlook for future augmentation costs.

FIGURE 14: DRIVERS OF HIGHER BESS 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



V.E. Implications for Net CONE

V.E.1. Indicative E&AS Offsets

Similar to the CC and CT, we recommend removing regulation revenues from the calculation of the E&AS offset for BESS. The regulation market is unlikely to continue to support similar prices in the future with the addition of significant BESS resources, especially in the case in which BESS resource are one of the primary resources that enter the market to meet future reserve requirements.

Removing regulation revenues has a greater impact on BESS E&AS offset than the CC and CT though because it currently makes up the majority of its revenues. Table 34 shows the current and updated 2023/24 E&AS revenue offset by zone with the steep decrease caused by the removal of regulation revenues.

TABLE 34: UPDATED 2023/24 BESS E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	4-Hour BESS		
	Current 2023/24 EAS	Removed Regulation	Updated 2023/24 EAS
CONE Area 1			
AECO	$414	-$294	$120
DPL	$427	-$285	$142
JCPL	$413	-$295	$118
PECO	$413	-$295	$118
PSEG	$414	-$294	$120
RECO	$419	-$291	$128
CONE Area 2			
BGE	$428	-$267	$161
PEPCO	$423	-$274	$149
CONE Area 4			
METED	$417	-$286	$132
PENELEC	$419	-$290	$128
PPL	$416	-$292	$124
CONE Area 3			
AEP	$418	-$286	$132
APS	$418	-$284	$134
ATSI	$419	-$284	$135
COMED	$425	-$281	$144
DAY	$420	-$281	$139
DEOK	$421	-$280	$141
DUQ	$421	-$283	$139
DOM	$424	-$276	$149
EKPC	$418	-$285	$134
OVEC	$407	-$295	$113
RTO	**$343**	**-$215**	**$128**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020.

V.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the BESS Net CONE shown for the reference CC. Table 28 Table 35 shows the indicative BESS Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 35: INDICATIVE BESS 2026/2027 NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	BESS 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE
CONE Area 1			
AECO	$858	$178	$679
DPL	$858	$208	$649
JCPL	$858	$175	$682
PECO	$858	$175	$683
PSEG	$858	$179	$679
RECO	$858	$189	$668
EMAAC	**$858**	**$184**	**$674**
CONE Area 2			
BGE	$875	$234	$641
PEPCO	$875	$219	$656
SWMAAC	**$875**	**$227**	**$648**
CONE Area 4			
METED	$843	$194	$648
PENELEC	$843	$190	$653
PPL	$843	$184	$659
MAAC	**$857**	**$193**	**$663**
CONE Area 3			
AEP	$830	$195	$635
APS	$830	$198	$632
ATSI	$830	$199	$631
COMED	$830	$211	$619
DAY	$830	$204	$625
DEOK	$830	$208	$622
DUQ	$830	$204	$626
DOM	$830	$218	$612
EKPC	$830	$197	$633
OVEC	$830	$168	$662
RTO	**$851**	**$189**	**$662**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

VI. List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
Btu	British Thermal Units
CAISO	California Independent System Operator
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
DCP	Dominion Cove Point
DJIA	Dow Jones Industrial Average
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kWh	Kilowatt-Hours
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million

MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NO_x	Nitrogen Oxides
NPV	Net Present Value
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VOC	Volatile Organic Compounds
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Combined-Cycle and Combustion Turbine Cost Details

A.1 Technical Specifications

The 2018 PJM CONE study demonstrated that the market was shifting away from the F-class and G-class frame type turbines that had been the dominant turbines over the prior several decades and with over half of the CC plants installed or under construction in PJM. Today, developers even more definitively exhibit preference for H/J-class turbines. Table 36 shows 72% and 58% of CC capacity under construction (since 2018) is from H/J-class turbines in PJM and the U.S., respectively. Among all such turbines, developers continue to select GE 7HA turbine, building on the industry’s many turbine-years of operating experience with that make and model. Other equivalent machines to the GE H-class machine such as the Siemens SGT6-8000H or the Mitsubishi M501J currently have lower market penetration.

TABLE 36: TURBINE MODEL OF COMBINED-CYCLE PLANTS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Turbine Model	PJM Installed Capacity *(MW)*	US Installed Capacity *(MW)*
General Electric 7HA	7,211	12,203
Mitsubishi M501J	3,645	3,645
Siemens SGT6-8000H	1,856	1,856
Mitsubishi M501G	1,444	4,015
General Electric 7F	828	4,130
Siemens SGT6-5000F	755	1,426
General Electric A650	717	717
Siemens SGT6-500	703	703
General Electric 6B.03	276	276
General Electric GRT	210	210
General Electric MS7001	0	1,000
Siemens SGT6-2000	0	232
Siemens SGT6-800	0	224
Solar Turbines Titan 130	0	29
Total	**17,645**	**30,666**
F/G Class Total	3,940	10,485
H/J Class Total	12,712	17,704

Sources and notes: Data is from Ventyx Energy Velocity Suite and S&P Global Market Intelligence, Accessed August 2021.

Sargent & Lundy reviewed the operational characteristics of starting up each reference resource and updated the parameters PJM includes in its historical simulations for setting the Net E&AS revenue offset in Table 37.

TABLE 37: RECOMMENDED OPERATING PARAMETERS FOR REFERENCE RESOURCES

Parameter	Unit	CT	CC
Installed Capacity	*MW*	367	1,182
Minimum Stable Level	*MW*	140	176
Ramp Rate	*MW/min*	15	30
Time to Start	*mins*	21	120
Minimum Runtime	*hours*	2	4
NOx Rate	*lb/MMBtu*	0.0093	0.0074
SO2 Rate	*lb/MMBtu*	0.0006	0.0006
Startup Gas Usage	*MMBtu/start*	456	7,988
Startup NOx Emissions	*lb/start*	55	160

A.2 Construction Labor Costs

Labor costs are comprised of “construction labor” associated with the EPC scope of work and “other labor” that includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Labor rates have been developed by S&L through a survey of prevalent wages in each region in 2021. The labor costs for a given task are based on trade rates weighted by the combination of trades required. In areas where multiple labor pools can be drawn upon the trade rates used are the average of the possible labor rates. The labor costs are based on a 5-day 10-hour workweek with per-diem included to attract skilled labor. Site overheads are carried as indirect costs, which is consistent with current industry practice whereas in 2014 site overheads were carried in the labor rates.

A summary of construction labor cost assumptions is shown below in Table 38.

TABLE 38: CONSTRUCTION LABOR COST ASSUMPTIONS

		EMAAC	SWMAAC	Rest of RTO	WMAAC
1x0 CT Plant					
2021 Construction Labor Hours	*hours*	256,453	239,508	243,744	256,453
2021 Weighted Average Crew Rates	*$*	137.66	118.34	122.59	122.44
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$41,657,600	$31,178,500	$33,466,500	$37,051,400
2021 Construction Labor Costs	*$/kW*	115	86	95	106
Double Train 1x1 CC Plant					
2021 Construction Labor Hours	*hours*	1,809,038	1,687,939	1,718,213	1,809,038
2021 Weighted Average Crew Rates	*$*	143.62	127.97	129.48	129.85
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$306,589,500	$237,598,100	$249,164,300	$277,181,900
2021 Construction Labor Costs	*$/kW*	294	227	244	274

Engineering, procurement, and project services are taken as 5% of project direct costs. Construction management and field engineering is taken as 2% of project direct costs. Start-up and commissioning is taken as 1% of project direct costs. These values are consistent with the 2018 CONE Study and are in-line with recent projects in which S&L has been involved.

A.3 Net Startup Fuel Costs

We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume zone-specific gas prices, including Transco Zone 6 Non-New York prices for EMAAC, Transco Zone 5 prices for SWMAAC, Columbia Appalachia prices for Rest of RTO, and Transco Leidy Receipts for WMAAC. All gas prices were calculated by using future/forward natural gas prices from OTC Global Holdings as of 10/10/2021 to estimate 2022 gas prices.
- **Electric Energy:** estimate prices based on zone-specific energy prices for the location of the reference resources in each CONE Area: AECO for EMAAC, PEPCO for SWMAAC, AEP for Rest of RTO, and PPL for WMAAC;[45] average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

[45] Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

TABLE 39: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING

	Energy Production			Fuel Consumption			
	Energy Produced	Energy Price	Energy Sales Credit	Natural Gas	Natural Gas Price	Natural Gas Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT							
1 Eastern MAAC	178,130	$36.24	$6.46	1,636,480	$3.61	$5.9	-$0.6
2 Southwest MAAC	179,290	$36.24	$6.50	1,647,134	$3.61	$5.9	-$0.6
3 Rest of RTO	173,913	$32.45	$5.64	1,598,262	$3.61	$5.8	$0.1
4 Western MAAC	172,584	$36.24	$6.25	1,586,224	$3.61	$5.7	-$0.5
Gas CC							
1 Eastern MAAC	1,027,945	$36.24	$37.26	6,468,335	$3.61	$23.3	-$13.9
2 Southwest MAAC	1,034,170	$36.24	$37.48	6,509,687	$3.61	$23.5	-$14.0
3 Rest of RTO	1,003,905	$32.45	$32.57	6,316,673	$3.61	$22.8	-$9.8
4 Western MAAC	996,320	$36.24	$36.11	6,269,141	$3.61	$22.6	-$13.5

Sources and notes: Energy production and fuel consumption estimated by S&L. Energy prices estimated by Brattle based on approach discussed in Section II.B of VRR curve report. Gas prices from OTC Global Holdings as of 10/10/2021.

A.4 Gas and Electric Interconnection Costs

Similar to the 2018 PJM CONE Study, we identified representative gas pipeline lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project-specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs. We escalated the project-specific costs to 2021 dollars based on the assumed long-term inflation rate of 2.4% (see Table 8 above). We then calculated the average per-mile costs of the laterals ($5.1 million/mile) and the station costs ($4.1 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 40.[46]

[46] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

TABLE 40: GAS INTERCONNECTION COSTS

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(service year $m)*	Pipeline Cost *(2021$m)*	Pipeline Cost *(2021$m/mile)*	Meter Station *(Y/N)*	Station Cost *(service year $m)*	Station Cost *(2021$m)*
Panda Power Lateral Project	TX	2014	16	16.5	$26	$31	$2	Y	$2.2	$2.6
Woodbridge lateral	NJ	2015	20	2.4	$32	$37	$15	Y	$3.5	$4.0
Rock Springs Expansion	PA,MD	2016	20	11.0	$80	$90	$8	Y	$3.3	$3.7
Western Kentucky Lateral Project	KY	2016	24	22.5	$81	$91	$4	Y	$4.8	$5.4
UGI Sunbury Pipeline	PA	2017	20	35.0	$178	$196	$6	Y	n.a.	n.a.
Willis Lateral Project	TX	2020	24	19.0	$96	$98	$5	Y	$4.3	$4.4
Average							**$5.1**			**$4.0**

Sources and notes: A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

Table 41 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CC reference resources. The costs are based on confidential, project-specific cost data provided by PJM for both the direct connection facilities and all necessary network upgrades. In the case where plants chose to build their own direct connection facilities and did not report their costs to PJM, we calculated the capacity-weighted average of the units with direct connection costs and applied them to the units without direct connection costs. We escalated the direct connection and network upgrade costs from the online service dates to 2021 dollars based on the assumed long-term inflation rate of 2.9%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $18.9/kW for setting the electrical interconnection of the CC reference resource.

TABLE 41: ELECTRIC INTERCONNECTION COSTS IN PJM

Plant Size	Observations *(count)*	Electrical Interconnection Cost Capacity Weighted Average *(2021$m)*	*(2021$/kW)*
< 500 MW	5	$7.2	$18.3
500-750 MW	5	$12.2	$20.7
> 750 MW	7	$23.9	$18.3
Capacity Weighted Average	**17**	**$18.8**	**$18.9**

Source and notes: Confidential project-specific cost data provided by PJM.

A.5 Land Costs

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We collected all publicly-available land listings for counties within each CONE area. We then calculated the acre-weighted average land price for each CONE area and escalated 1 year using the long-term inflation rate of 2.2%. There is a wide range of prices within the same CONE Area as shown in Table 42.

TABLE 42: CURRENT LAND ASKING PRICES

CONE Area	**Current Asking Prices**		
	Observations *(count)*	Range *(2022$/acre)*	Land Price *(2022$/acre)*
1 EMAAC	7	$14,430 - $206,620	$96,361
2 SWMAAC	2	$13,148 - $42,785	$29,504
3 RTO	6	$9,867 - $37,429	$16,376
4 WMAAC	6	$22,49 - $68,14	$30,628

Sources and notes: We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

A.6 Property Taxes

Table 43 summarizes the calculations for the effective tax rates of each CONE area. We collected nominal tax rates, assessment ratios, and depreciation rates for counties of each CONE area. Using the nominal tax rates and assessment ratios, the effective tax rate for each CONE area was calculated by multiplying the average nominal tax rate and assessment ratio for counties within each CONE area state.

TABLE 43: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
		(%)	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%/yr)*
1 EMAAC								
New Jersey	[1]	4.0%	96.2%	3.8%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.7%	50.0%	1.3%	3.3%
3 RTO								
Ohio	[3]	5.5%	35.0%	1.9%	5.5%	24.0%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	[4]	2.7%	100.0%	2.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.8%	99.0%	3.8%	n/a	n/a	n/a	n/a

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. For Gloucester County see:
https://tax1.co.monmouth.nj.us/cgi-bin/prc6.cgi?&ms_user=monm&passwd=data&srch_type=0&adv=0&out_type=0&district=0801
For Camden county see:
https://www.camdencounty.com/wp-content/uploads/2020/11/04CAMDEN.2021-Ratios.pdf
https://www.camdencounty.com/wp-content/uploads/2020/11/2021-County-Tax-Rates.pdf

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJ Rev Stat § 54:4-1 (2016).

[2a],[2c] Maryland tax rates estimated based on average county tax rates in Charles county and Prince George's county in 2017-2018. Data obtained from Maryland Department of Assessments & Taxation website:
https://dat.maryland.gov/Documents/statistics/Taxrates_2021.pdf

[2d] MD Tax-Prop Code § 7-237 (2016)

[2e] Phone conversation with representative at Charles County Treasury Department.

[3a],[3c] Ohio rates estimated based on the average effective tax rates from Trumbull and Carroll counties. For Trumbull county see:
http://auditor.co.trumbull.oh.us/pdfs/2020%20RATE%20OF%20TAXATION.pdf
For Caroll County see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202020.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 124 and 129:
http://www.tax.ohio.gov/Portals/0/communications/publications/annual_reports/2016AnnualReport/2016AnnualReport.pdf

[3e] Depreciation schedules for utility assets found in Form U-El by Ohio Department of Taxation:
http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2017/PUE_UEL.xls

[4a] Pennsylvania county tax rates for RTO based on the county of Lawrence, available at:
https://lawrencecountypa.gov/wp-content/uploads/2021/07/2021-millage.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1)* , only real estate tax assessed by local governments.

[5a] Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties:
https://www.luzernecounty.org/DocumentCenter/View/26403/2021-MILLAGES-JULY
https://www.lyco.org/Portals/1/Assessment/Documents/2021%20Millage.pdf?ver=2021-01-29-090920-517
https://bradfordcountypa.org/wp-content/uploads/2021/09/Bradford-County-Mill-Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note assessment ratios above 100% are capped at 100% in our calculations.

[5c]-[5e] According to Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1), only real estate tax assessed by local governments.

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Introduction

This document provides information for PJM stakeholders regarding the results of the 2024/2025 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.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. 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 and DEOK were modeled as LDAs in the 2024/2025 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.

Executive Summary

The 2024/2025 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 140,415.8 MW of unforced capacity in the RTO from non-energy efficiency annual, summer-period, and winter-period resources representing a 21.7% 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 reserve margin for the entire RTO, which includes Fixed Resource Requirement (FRR) is 20.4% or 5.7 percentage points higher than the target reserve margin of 14.7%. These results are similar to the 2023/2024 BRA.

Supply offered into the RPM capacity market, excluding EE Resources, declined 2,197.7 MW from 151,143.4 MW in the 2023/2024 BRA to 148,945.7 MW in the 2024/2025 BRA. This is the third BRA in a row where the total Capacity offered from non-EE resources has declined. Further, the number of constrained LDAs increased from 3 constrained LDAs in the 2023/2024 BRA to 5 constrained LDAs in the 2024/2025 BRA. This reflects tighter supply and demand conditions in those locations. The total amount of capacity, excluding EE Resources, in RPM that cleared increased 542.2 MW from 139,873.6 MW in the 2023/2024 BRA to 140,415.8 MW in the 2024/2025 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.

Resource Clearing Prices (RCPs) for the 2024/2025 BRA for CP Resources located in the rest of RTO declined from $34.13/MW-day to $28.92/MW-day. The number of constrained LDAs increase from 3 LDAs (MAAC, BGE, DPL-S) to 5 LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK). MAAC prices remained the same at $49.49/MW-day while prices for the other 4 constrained LDAs increased: EMAAC increased from $49.49/MW-day to $54.95/MW-day, DPL-S increased from $69.95/MW-day to $90.64/MW-day, BGE increased by $69.95/MW-day to $73.00/MW-day, and DEOK increased from $34.13/MW-day to $96.24/MW-day.

For the 24/25 BRA, total offered and FRR committed resources (includes annual, summer period and winter period) was 1,384 MW lower than in the prior BRA. Key changes in offered supply include:

- Decrease in Coal (-2,050 MW), Water/Hydro (-237 MW), DR (-318 MW) and Wind (-212 MW)
- Increase in Solar (+1,290 MW) and Natural Gas (+252 MW)

For the 24/25 BRA, total cleared and FRR committed resources (includes annual, summer period and winter period) was 1,356 MW higher than in the prior BRA. Key changes in cleared and FRR committed resources include:

- Decrease in DR (-451 MW), Water/Hydro (-237 MW), and Nuclear (-331 MW) and Coal (-278 MW)
- Increase in Natural Gas (+1,615 MW), Solar (+1,297 MW)

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

- The auction results were postponed and then finalized based on FERC order (ER23-729-000), issued on Feb. 21.
- Planning parameters (please see the Planning Parameters Report for various changes:
    - netCONE values used to determine the VRR curve were marginally higher (+6.2% to +7.2%) based on the normal escalation process.
    - RTO Reliability Requirement increased by only 236 MW from 131,820 MW to 132,056 MW (or 0.2%) although there were some significant LDA Reliability Requirement changes.

Note: This BRA was conducted under a compressed auction schedule where the auction occurred ~17 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 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins for the 2007/2008 through 2024/2025 RPM BRAs. The Reserve Margin presented in Table 1 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 Fixed Resource Requirement alternative). The reserve margin for the entire RTO is 20.4%, or 5.7 percentage points higher than the target reserve margin of 14.7%, when the Fixed Resource Requirement (FRR) load and resources are considered. The reserve margin for the RTO was only 0.1% points higher than the prior BRA.

Table 1 - RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results			
Delivery Year	Resource Clearing Price		Cleared UCAP (MW)	Reserve Margin
2007/2008	$	40.80	129,409.2	19.1%
2008/2009	$	111.92	129,597.6	17.4%
2009/2010	$	102.04	132,231.8	17.6%
2010/2011	$	174.29	132,190.4	16.4%
2011/2012[1]	$	110.00	132,221.5	17.9%
2012/2013	$	16.46	136,143.5	20.5%
2013/2014[2]	$	27.73	152,743.3	19.7%
2014/2015[3]	$	125.99	149,974.7	18.8%
2015/2016[4]	$	136.00	164,561.2	19.3%
2016/2017[5]	$	59.37	169,159.7	20.3%
2017/2018	$	120.00	167,003.7	19.7%
2018/2019	$	164.77	166,836.9	19.8%
2019/2020	$	100.00	167,305.9	22.4%
2020/2021[6]	$	76.53	165,109.2	23.3%
2021/2022	$	140.00	163,627.3	21.5%
2022/2023	$	50.00	144,477.3	19.9%
2023/2024	$	34.13	144,870.6	20.3%
2024/2025	$	28.92	147,478.9	20.4%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers
7) Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1)

Table 2 below provides a summary of the clearing prices by Constrained LDA. Resource Clearing Prices (RCPs) for the 2024/2025 BRA for CP Resources located in the rest of RTO declined from $34.13/MW-day to $28.92/MW-day. The number of constrained LDAs increased from 3 LDAs (MAAC, BGE, DPL-S) to 5 LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK). MAAC prices remained the same at $49.49/MW-day while price for the other 4 constrained LDAs increased: EMAAC increased from $49.49/MW-day to $54.95/MW-day, DPL-S increased from $69.95/MW-day to $90.64/MW-day, BGE increased by $69.95/MW-day to $73.00/MW-day, and DEOK increased from $34.13/MW-day to $96.24/MW-day.

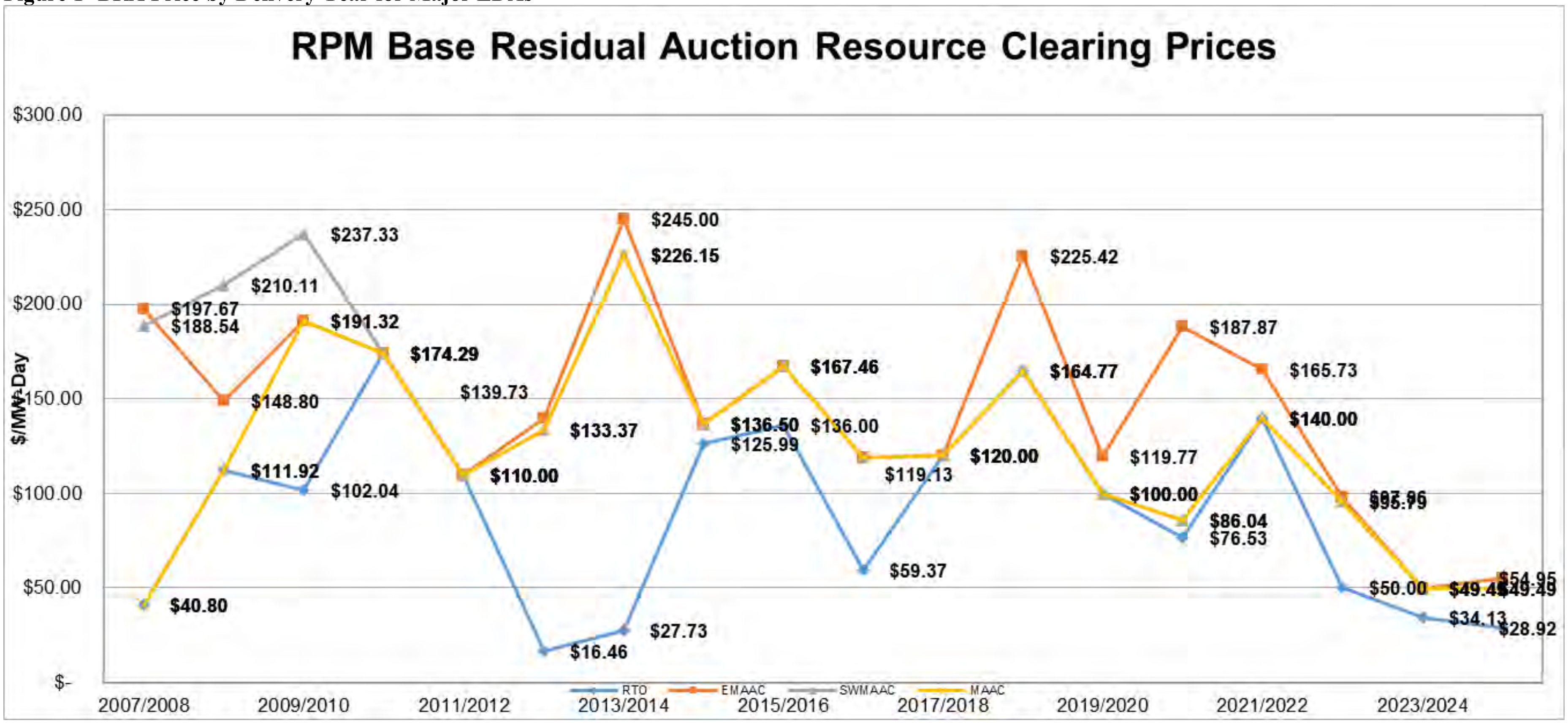
Since the MAAC, EMAAC, DPL-South, BGE and DEOK were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2024/2025 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher 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.

Table 2 – Comparison of BRA Clearing Price by Delivery Year by Constrained LDA

Capacity Type	BRA	BRA Resource Clearing Prices ($/MW-day)")					
		Rest of RTO	MAAC	EMAAC	DPL-SOUTH	BGE	DEOK
Capacity Performance	2024/2025	$28.92	$49.49	$54.95	$90.64	$73.00	$96.24
Capacity Performance	2023/2024	$34.13	$49.49	$49.49	$69.95	$69.95	$34.13

Figure 1 represents the trend in BRA Capacity price by Delivery Year for RTO, EMAAC, SWMAAC and MAAC. RTO prices were down from $34.13/MW-day to $28.92/MW-day. MAAC prices remained the same and EMAAC prices were up from $49.49/MW-day to $54.95/MW-day. SWMAAC was not constrained and had the same prices as MAAC.

Figure 1- BRA Price by Delivery Year for Major LDAs



* 2014/2015 through 2024/2025 Prices reflect the Annual Resource Clearing Prices.

Table 3 provides the offered and cleared MWs and associated Prices by LDA. This table provides an indication of how much supply did not clear for each LDA. For example, DPL-South had only 26.9 MW of additional supply that did not clear but it was for summer only resources that could not be matched with available Winter MWs and therefore did not clear. EMAAC, DPL-South, PSEG, PSEG-North, and DEOK all had less than 5% MW offered in excess of cleared MW.

Table 3 - Offered and Cleared MWs and associate Prices by LDA

Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED	DAY	DEOK
Offered MW (UCAP)*	157,362.7	68,615.8	8,973.1	3,651.1	2,942.1	31,661.6	1,448.9	6,362.3	3,571.6	10,351.3	2,015.5	10,750.3	27,502.8	1,052.9	2,115.9
Cleared MW (UCAP)**	147,478.9	64,200.8	8,472.5	3,421.0	2,671.6	30,670.5	1,422.0	6,111.8	3,470.8	9,716.7	1,885.2	10,004.5	25,152.0	985.4	2,060.0
System Marginal Price	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92	$28.92
Locactional Price Adder***	$0.00	$20.57	$0.00	$0.00	$23.51	$5.46	$35.69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$67.32
RCP for Capacity Performance Resources	$28.92	$49.49	$49.49	$49.49	$73.00	$54.95	$90.64	$54.95	$54.95	$28.92	$28.92	$49.49	$28.92	$28.92	$96.24

* 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 w ithin the LDA
*** Locational Price Adder is w ith respect to the immediate parent LDA

As seen in the table below, the 2024/2025 BRA procured 328.5 MW of capacity from new generation and 173.8 MW from uprates to existing or planned generation. The quantity of new generation is significantly down from last BRA where there was 3,329.7 MW of new generation. The quantity of capacity procured from external Generation Capacity Resources in the 2024/2025 BRA is 1,397.6 MW. All external generation capacity that cleared in the 2024/2025 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2024/2025 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2024/2025 BRA is 7,992.7 MW, and the total quantity of EE procured in the 2024/2025 BRA is 7,668.7 MW.

[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 Capacity Import Limit 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 Capacity Import Limit.

Table 4- Cleared MWs (UCAP) by Type by Delivery Year

BRA Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2024/2025	328.5	173.8	1,397.6	7,992.7	7,668.7
2023/2024	3,329.7	404.8	1,396.6	8,096.2	5,471.1
2022/2023	4,843.6	1,210.3	1,558.0	8,811.9	4,810.6
2021/2022	893.0	508.3	4,051.8	11,125.8	2,832.0
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

*All MW Values are in UCAP Terms

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2024/2025 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 209,800.5 MW of installed capacity was eligible to be offered into the 2024/2025 Base Residual Auction, with 1,617.1 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2024/2025 auction increased slightly to 1,522.7 MW from that of the previous auction and FRR commitments increased to 34.584.2 MW.

A total of 154,062.3 MW of Generation and DR capacity was offered into the Base Residual Auction. This is a decrease of 1,791.6 MW from that which was offered into the 2023/2024 BRA. EE resources are already included in the forecast and therefore do not help meet the reliability requirement. A total of 48,009.3 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, (3) having been excused from offering into the auction or (4) are 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 5 – Total RTO Resources (RPM + FRR) offered vs unoffered by Resource Type

	RTO[1]																
Auction Supply (all values in ICAP)	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012[2]**	**2012/2013**	**2013/2014[3]**	**2014/2015[4]**	**2015/2016[5]**	**2016/2017[6]**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**	**2024/2025**
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4	199,375.5	207,559.1	208,098.0	202,477.4	203,300.6	207,579.6	207,555.1	211,625.2	207,339.8	204,006.6	208,183.4
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1	7,620.2	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
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**	**206,995.7**	**212,208.8**	**216,510.2**	**208,778.3**	**209,025.2**	**212,401.0**	**212,995.6**	**216,350.2**	**208,988.9**	**205,607.8**	**209,800.5**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5	1,230.1	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
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1	33,612.7	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
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7	3,255.2	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	7,826.4	8,923.8	1,960.0	9,714.6	11,902.4
Total Eligible RPM Capacity: Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**	**38,098.0**	**25,929.6**	**25,319.4**	**21,304.6**	**19,454.8**	**18,158.0**	**23,077.8**	**23,901.0**	**36,782.4**	**44,734.2**	**48,009.3**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**	**192,449.2**	**172,206.5**	**160,873.6**	**161,791.2**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1	153,048.1	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
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7	15,043.1	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
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4	806.5	907.8	1,112.6	1,289.0	1,205.5	1,517.4	2,062.9	2,713.8	4,656.4	5,019.7	7,728.9
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**	**192,449.2**	**172,206.5**	**160,873.6**	**161,791.2**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1]RTO numbers include all LDAs.
[2]All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.
[3]2013/2014 includes ATSI zone and generation
[4]2014/2015 includes Duke zone and generation
[5]2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
[6]2016/2017 includes EKPC zone

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR), when applicable, for the Delivery Year.

Total offered Gen and DR used to meet the reliability requirement declined from 151,143.4 MW to 148,945.7 MWs. That is a 2,197.7 MW decrease in the amount of supply in the Capacity Market.

Table 6 - Capacity Resource offered and cleared by type by Delivery Year

	RTO*																
Auction Results	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**	**2024/2025**
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8	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
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6	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
EE Offered	-	-	-	-	652.7	756.8	831.9	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
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**	**178,587.7**	**184,380.0**	**178,838.5**	**179,891.2**	**185,539.5**	**183,351.5**	**186,504.8**	**167,698.4**	**156,614.5**	**157,362.7**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2	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
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	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
EE Cleared	0.0	0.0	0.0	0.0	568.9	679.4	822.1	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
Total Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**	**164,561.2**	**169,159.7**	**167,003.7**	**166,836.9**	**167,305.9**	**165,109.2**	**163,627.3**	**144,477.3**	**144,870.6**	**147,478.9**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6	14,026.5	15,220.3	11,834.8	13,054.3	18,233.6	18,242.3	22,877.5	23,221.1	11,743.9	9,883.8

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

***Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

***Starting 2020/2021: Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

Table 7 shows the offered and cleared MWs by Resource type for RPM over the last 4 Delivery Years. Table 8 provides the change in MWs by Delivery Year to illustrate the trend over the last four BRAs. Table 9 shows the offered and cleared MWs by Resource type for RPM plus FRR commitments over the last four Delivery Years. Table 10 provides the change in MWs by Delivery Year to illustrate the trend over the last four BRAs for overall supply to RPM and FRR areas. Table 9 and 10 provide a comprehensive picture of the trend in Supply since FRR participation has changed over the last four BRAs and resources may change from to FRR or RPM. Table 10 indicates that total RPM offered and FRR committed supply is down over the last three BRAs. 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.

For the 24/25 BRA, total offered and FRR committed resources (includes annual, summer period and winter period) was 1,384 MW lower than in the prior BRA. Key changes in offered supply include:

- Decrease in Coal (-2,050 MW), Water/Hydro (-237 MW), DR (-318 MW) and Wind (-212 MW)
- Increase in Solar (+1,290 MW) and Natural Gas (+252 MW)

For the 24/25 BRA, total cleared and FRR committed resources (includes annual, summer period and winter period) was 1,356 MW higher than in the prior BRA. Key changes in cleared and FRR committed resources include:

- Decrease in DR (-451 MW), Water/Hydro (-237 MW), and Nuclear (-331 MW) and Coal (-278 MW)
- Increase in Natural Gas (+1,615 MW), Solar (+1,297 MW)

Table 7 -Offered and Cleared MWs by Type for RPM for previous BRAs

Delivery Year Data	2021/2022 Offered UCAP	2021/2022 Cleared UCAP	2022/2023 Offered UCAP	2022/2023 Cleared UCAP	2023/2024 Offered UCAP	2023/2024 Cleared UCAP	2024/2025 Offered UCAP	2024/2025 Cleared UCAP
Coal	44,936	39,022	33,935	27,411	26,968	21,615	25,060	21,478
Distillate Oil (No.2)	3,254	3,155	2,977	2,696	2,684	2,645	2,592	2,490
Gas	77,514	74,814	75,526	69,292	74,552	70,978	73,714	71,504
Nuclear	30,561	19,918	26,855	21,050	26,365	26,365	26,024	25,818
Oil	5,218	3,955	2,419	2,271	1,901	1,820	2,150	1,876
Solar	625	570	2,049	1,512	1,878	1,868	2,768	2,765
Water	6,708	6,229	4,324	4,157	3,677	3,677	3,715	3,715
Wind	1,442	1,417	2,484	1,728	1,486	1,294	1,272	1,272
Battery	-	-	-	-	-	-	-	-
Hybrid	-	-	-	-	-	-	-	-
Other	1,406	1,305	1,077	1,040	1,005	1,005	1,001	1,001
Demand Response	11,887	11,126	10,513	8,812	10,117	8,096	10,146	7,993
Aggregate Resource	-	-	484	386	511	511	503	503
Grand Total (w/o EE)	183,550	161,511	162,642	140,354	151,143	139,874	148,946	140,416
Energy Efficiency	2,955	2,832	5,057	4,811	5,471	5,471	8,417	7,669
Grand Total (w/EE)	186,505	164,343	167,698	145,164	156,615	145,345	157,363	148,085

The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY

Notes:

- Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.
- Aggregate Resource category includes aggregates resources of different resource types
- Other = Kerosene, Other Gas, Other Liquid, Other Solid, Wood
- Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance

Table 8 - Change in Offered and Cleared MWs by Type for RPM for previous BRAs

	Change in Offered MWs			Change in Cleared MWs		
Data	2022/2023-2021/2022	2023/2024-2022/2023	2024/2025-2023/2024	2022/2023-2021/2022	2023/2024-2022/2023	2024/2025-2023/2024
Coal	(11,001)	(6,967)	(1,908)	(11,612)	(5,796)	(136)
Distillate Oil (No.2)	(278)	(292)	(92)	(460)	(51)	(155)
Gas	(1,988)	(974)	(837)	(5,522)	1,685	526
Nuclear	(3,706)	(490)	(341)	1,132	5,315	(547)
Oil	(2,799)	(518)	249	(1,684)	(451)	57
Solar	1,424	(171)	890	942	357	897
Water	(2,383)	(647)	37	(2,072)	(480)	37
Wind	1,042	(998)	(214)	311	(434)	(22)
Battery	-	-	-	-	-	-
Hybrid	-	-	-	-	-	-
Other	(330)	(71)	(4)	(265)	(34)	(4)
Demand Response	(1,374)	(396)	30	(2,314)	(716)	(103)
Aggregate Resource	484	27	(7)	386	125	(7)
Grand Total (w/o EE)	(20,908)	(11,498)	(2,198)	(21,157)	(480)	542
Energy Efficiency	2,102	414	2,946	1,979	660	2,198

Table 9 - Offered and Cleared MWs by Type for RPM and committed FRR for previous BRAs

Delivery Year Data	2021/2022 Offered UCAP	2021/2022 Cleared UCAP	2022/2023 Offered UCAP	2022/2023 Cleared UCAP	2023/2024 Offered UCAP	2023/2024 Cleared UCAP	2024/2025 Offered UCAP	2024/2025 Cleared UCAP
Coal	53,444	47,531	45,754	39,230	37,164	31,811	35,114	31,532
Distillate Oil (No.2)	3,254	3,155	3,178	2,897	2,894	2,855	2,776	2,674
Gas	78,863	76,164	85,562	79,329	85,217	81,643	85,469	83,258
Nuclear	32,541	21,898	31,944	26,140	31,960	31,960	31,835	31,629
Oil	5,218	3,955	2,674	2,527	2,350	2,269	2,493	2,220
Solar	644	589	2,633	2,096	2,945	2,935	4,234	4,232
Water	7,239	6,760	6,917	6,749	6,375	6,375	6,137	6,137
Wind	1,551	1,526	2,595	1,839	1,608	1,416	1,396	1,396
Battery	-	-	-	-	16	16	36	36
Hybrid	-	-	-	-	-	-	10	10
Other	1,419	1,318	1,205	1,168	1,185	1,185	1,153	1,153
Demand Response	12,114	11,353	10,604	8,903	10,652	8,631	10,334	8,180
Aggregate Resource	-	-	484	386	511	511	503	503
Grand Total (w/o EE)	196,288	174,249	193,551	171,263	182,875	171,605	181,491	172,961
Energy Efficiency	2,955	2,832	5,057	4,811	5,471	5,471	8,417	7,669
Grand Total (w/EE)	199,243	177,081	198,608	176,073	188,346	177,076	189,908	180,630

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.
- Aggregate Resource category includes aggregates resources of different resource types
- Other = Kerosene, Other Gas, Other Liquid, Other Solid, Wood
- Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance

Table 10 - Change in Offered and Cleared MWs by Type for RPM and committed FRR for previous BRAs

	Change in Offered MWs			Change in Cleared MWs		
Data	2022/2023-2021/2022	2023/2024-2022/2023	2024/2025-2023/2024	2022/2023-2021/2022	2023/2024-2022/2023	2024/2025-2023/2024
Coal	(7,690)	(8,590)	(2,050)	(8,301)	(7,419)	(278)
Distillate Oil (No.2)	(77)	(283)	(118)	(259)	(42)	(181)
Gas	6,699	(346)	252	3,165	2,314	1,615
Nuclear	(596)	16	(125)	4,242	5,820	(331)
Oil	(2,544)	(325)	143	(1,429)	(258)	(49)
Solar	1,989	311	1,290	1,507	839	1,297
Water	(322)	(542)	(237)	(11)	(374)	(237)
Wind	1,044	(988)	(212)	314	(423)	(20)
Battery	-	16	20	-	16	20
Hybrid	-	-	10	-	-	10
Other	(214)	(20)	(32)	(150)	17	(32)
Demand Response	(1,510)	48	(318)	(2,451)	(272)	(451)
Aggregate Resource	484	27	(7)	386	125	(7)
Grand Total (w/o EE)	(2,738)	(10,676)	(1,384)	(2,987)	343	1,356
Energy Efficiency	2,102	414	2,946	1,979	660	2,198

Capacity Import Participation

The quantity of capacity imports cleared in the 2024/2025 BRA were 1,397.6 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 Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2024/2025 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 11 - Capacity Imports (UCAP) Offered and Cleared by Region

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	220.8	0.0	807.9	238.0	260.4	**1,527.1**
Cleared MW (UCAP)	220.8	0.0	678.4	238.0	260.4	**1,397.6**
Resource Clearing Price ($/MW-day)	$28.92	$28.92	$28.92	$28.92	$28.92	

*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.

The Table below provides a breakdown of the offered and cleared MWs by season by Resource Type. There were 1,081 MW of Summer capability and 605.6 MW of Winter capability offered in the auction. All 605.6 MW of Winter were matched with Summer resources to meet the annual Capacity Performance capability requirement.

Table 12 – Offered and Cleared (UCAP) by Resource Type by Season

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual Capacity Performance	Summer Capacity Performance	Winter Capacity Performance	Annual Capacity Performance	Summer Capacity Performance	Winter Capacity Performance
GEN	138,153.2	40.5	605.6	131,779.3	38.2	605.6
DR	9,942.8	203.6	-	7,804.3	188.4	-
EE	7,580.1	836.9	-	7,289.7	379.0	-
Grand Total	**155,676.1**	**1,081.0**	**605.6**	**146,873.3**	**605.6**	**605.6**

Figure 2 provide the trend in offered and cleared DR and EE by Delivery Year. While DR offered and cleared has been moderately down over the last 3 Delivery Years, EE continues to increase and was significantly up in the 2024/2025 BRA. The amount of PRD remains small and is slightly up in the 2024/2025 Delivery Year.

Figure 2 - DR and EE offered and cleared MW by Delivery Year by Type

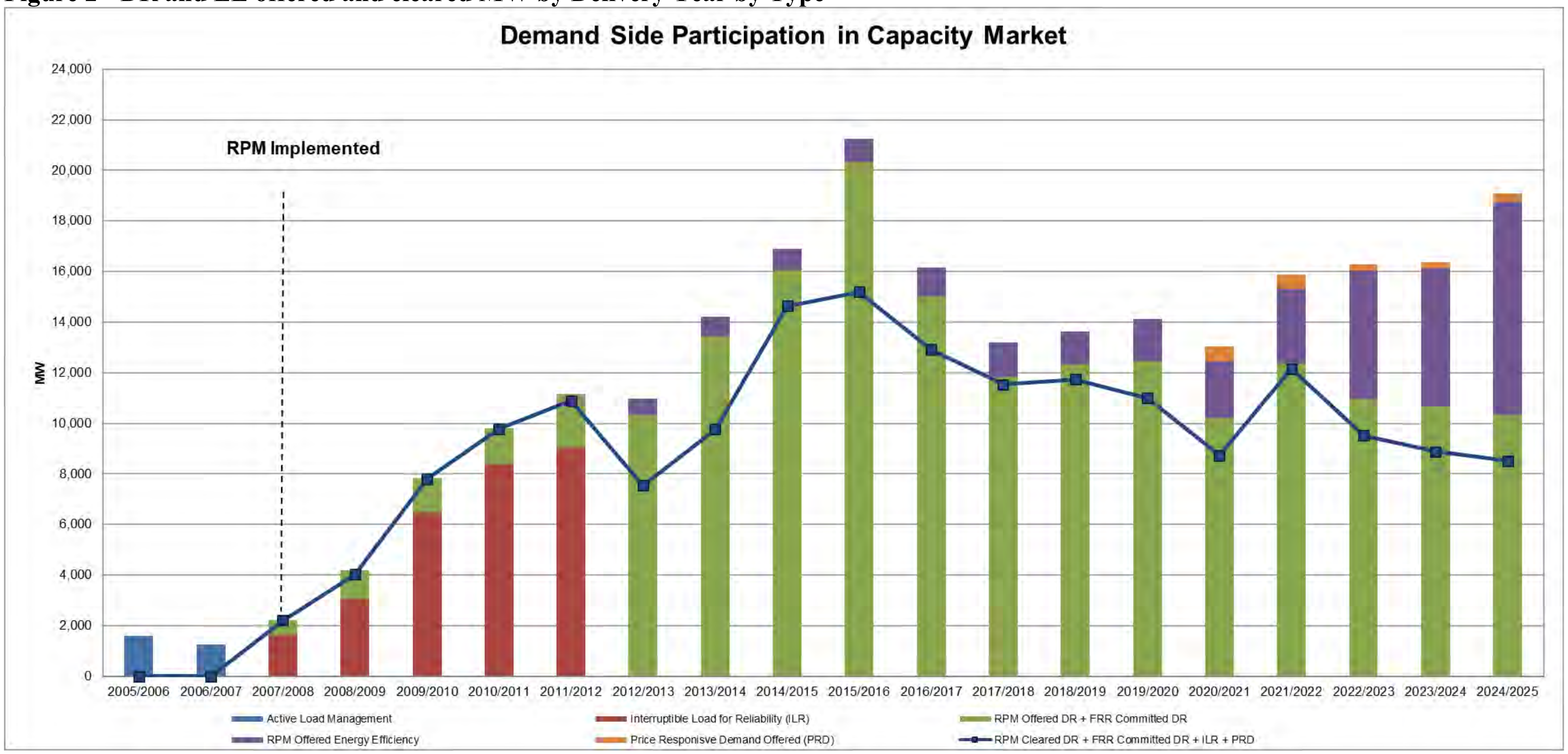


Table 13 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (2,605.4 MW), followed by AEP (1,893.6 MW) and then DOM (1,611.6 MW). In most cases, the amount of DR and EE is correlated to the size of the load in the Zone.

Table 13 - DR and EE offered and cleared by LDA

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	93.8	153.8	247.6	66.8	152.0	218.8
EMAAC/DPL-S	DPL	173.1	208.2	381.3	147.7	202.4	350.1
EMAAC	JCPL	175.1	326.8	501.9	131.8	317.4	449.2
EMAAC	PECO	429.3	615.8	1,045.1	366.3	583.9	950.2
PSEG/PS-N	PSEG	389.0	817.2	1,206.2	285.7	771.4	1,057.1
EMAAC	RECO	3.4	3.2	6.6	2.7	3.2	5.9
EMAAC Sub Total		**1,263.7**	**2,125.0**	**3,388.7**	**1,001.0**	**2,030.3**	**3,031.3**
PEPCO	PEPCO	232.0	421.1	653.1	164.5	398.9	563.4
BGE	BGE	224.1	392.9	617.0	198.1	380.3	578.4
MAAC	METED	258.4	166.3	424.7	218.8	157.1	375.9
MAAC	PENELEC	347.6	148.0	495.6	314.0	140.6	454.6
PPL	PPL	658.4	422.0	1,080.4	608.7	392.9	1,001.6
MAAC Sub Total**		**2,984.2**	**3,675.3**	**6,659.5**	**2,505.1**	**3,500.1**	**6,005.2**
RTO	AEP	1,590.1	883.4	2,473.5	1,102.8	790.8	1,893.6
RTO	APS	861.8	407.9	1,269.7	635.1	375.8	1,010.9
ATSI/ATSI-C	ATSI	953.5	689.1	1,642.6	674.6	587.3	1,261.9
COMED	COMED	1,899.8	1,284.7	3,184.5	1,542.0	1,063.4	2,605.4
DAY	DAY	233.5	146.1	379.6	191.1	128.3	319.4
DEOK	DEOK	231.2	202.2	433.4	221.9	188.1	410.0
RTO	DOM	892.4	977.2	1,869.6	710.5	901.1	1,611.6
RTO	DUQ	210.9	151.1	362.0	120.6	133.8	254.4
RTO	EKPC	289.0	-	289.0	289.0	-	289.0
Grand Total		**10,146.4**	**8,417.0**	**18,563.4**	**7,992.7**	**7,668.7**	**15,661.4**

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

** MAAC sub-total includes all MAAC Zones

Price Responsive Demand Participation

332 MW (UCAP) of PRD was elected and committed in the 2024/2025 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing 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 which indicates the Nominal PRD Value in MWs 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: 174 MW in the BGE, 120 MW in the PEPCO LDA, 24 MW in the rest of EMAAC LDA and 14 MW were located in the DPL-South 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.

2023/2024 RPM Base Residual Auction Results

Executive Summary

The 2023/2024 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 144,870.6 MW of unforced capacity in the RTO representing a 21.6% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2023/2024 Delivery Year as procured in the BRA is 20.3%, or 5.5 percentage points higher than the target reserve margin of 14.8%. This reserve margin was achieved at clearing prices that are between approximately 12% to 32% of Net CONE, depending upon the Locational Deliverability Area (LDA).

2023/2024 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2023/2024 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $34.13/MW-day. MAAC, DPL-SOUTH, and BGE were constrained LDAs in the 2023/2024 BRA with RCP of $49.49/MW-day, $69.95/MW-day, and $69.95/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2022/2023 BRA was $50.00/MW-day. Additionally, the MAAC, EMAAC, BGE, COMED, and DEOK LDA were constrained LDAs in the 2022/2023 BRA with RCPs of $95.79/MW-day, $97.86 /MW-day, $126.50/MW-day, $68.96/MW-day, and $71.69/MW-day respectively.

2023/2024 BRA Resource Clearing Prices

	2023/2024 BRA Resource Clearing Prices ($/MW-day)			
Capacity Type	Rest of RTO	MAAC	DPL-SOUTH	BGE
Capacity Performance	$34.13	$49.49	$69.95	$69.95

2023/2024 RPM Base Residual Auction Results

2023/2024 BRA Cleared Capacity Resources

As seen in the table below, the 2023/2024 BRA procured 3,329.7 MW of capacity from new generation and 404.8 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2023/2024 BRA is 1,396.6 MW which is a decrease of 161.4 MW from that procured in the 2022/2023 BRA. All external generation capacity that has cleared in the 2023/2024 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2023/2024 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2023/2024 BRA is 8,096.2 MW which is a decrease of 715.7 MW from that procured in the 2022/2023 BRA; and, the total quantity of EE procured in the 2023/2024 BRA is 5,471.1 MW, which is an increase of 660.5 MW from that procured in the 2022/2023 BRA.

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2023/2024 BRA

BRA Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2023/2024	3,329.7	404.8	1,396.6	8,096.2	5,471.1
2022/2023	4,843.6	1,210.3	1,558.0	8,811.9	4,810.6
2021/2022	893.0	508.3	4,051.8	11,125.8	2,832.0
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

*All MW Values are in UCAP Terms

[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 Capacity Import Limit 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 Capacity Import Limit.

2023/2024 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2023/2024 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2023/2024 BRA opened on June 8, 2022, and the results were posted on June 21, 2022.

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.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. 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.

This document begins with a high-level summary of the BRA results followed by sections containing detailed descriptions of the 2023/2024 BRA results and a discussion of the results in the context of the previous BRAs.

Summary of Results

The 2023/2024 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 144,870.6 MW of unforced capacity in the RTO representing a 21.6% reserve margin. The reserve margin for the entire RTO is 20.3%, or 5.5 percentage points higher than the target reserve margin of 14.8%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2023/2024 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $34.13/MW-day. MAAC, DPL-SOUTH, and BGE were constrained LDAs in the 2023/2024 BRA with RCPs, in regards to the immediate parent LDA, of $49.49/MW-day, $69.95/MW-day, and $69.95/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2022/2023 BRA was $50.00/MW-day. Additionally, the MAAC, EMAAC, BGE, COMED, and DEOK LDA were constrained LDAs in the 2022/2023 BRA with RCPs of $95.79/MW-day, $97.86 /MW-day, $126.50/MW-day, $68.96/MW-day, and $71.69/MW-day respectively.

The quantity of Unforced Capacity procured from new Generation Capacity Resources cleared regardless of whether they had offered into a prior auction was 3,734.5 MW comprised of 3,329.7 MW from new generation units and 404.8 MW from uprates to existing or planned generation units.

The quantity of Unforced Capacity procured from external Generation Capacity Resources in the 2023/2024 BRA is 1,396.6 MW which is a decrease of 161.4 MW from that procured in the 2022/2023 BRA. All external generation capacity that has cleared in the 2023/2024 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2023/2024 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

The total Unforced Capacity of DR procured in the 2023/2024 BRA is 8,096.2 MW which is a decrease of 715.7 MW from that procured in the 2022/2023 BRA; and, the total quantity of EE procured in the 2023/2024 BRA is 5,471.1 MW which is an increase of 660.5 MW from that procured in the 2022/2023 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.

The following is a list of market rule changes that became effective for this BRA:

- The Minimum Offer Price Rule (MOPR) was updated and applied to Generation Capacity Resources that received Conditioned State Support or where the Capacity Market Seller had Buyer Side Market Power.
- The Market Seller Offer Cap (MSOC) default based on netCONE was eliminated and all Existing Resources subject to MSOC received a unit specific net Energy and Ancillary Service (EAS) offset. Further, the netEAS offset was changed from forward looking to a historic calculation.
- Intermittent resource and storage (ELCC Resources) capacity accreditation used the Effective Load Carrying Capability (ELCC) methodology.
- The Energy Efficiency (EE) addback to the reliability requirement was made equal to the amount of EE that cleared through an iterative process as part of the final auction solution.

2023/2024 RPM Base Residual Auction Results

- This BRA was conducted under a compressed auction schedule where the auction occurred one year prior to the start of the delivery year. A typical BRA is held three years before the start of the delivery year.

A further discussion of the 2023/2024 BRA results and additional information regarding the 2023/2024 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2023/2024 auction results to the results from the 2007/2008 through 2022/2023 RPM Auctions.

2023/2024 RPM Base Residual Auction Results

2023/2024 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins for the 2007/2008 through 2023/2024 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%
2022/2023	$ 50.00	144,477.3	19.9%
2023/2024	$ 34.13	144,870.6	20.3%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers
7) Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1)

2023/2024 RPM Base Residual Auction Results

The Reserve Margin presented in Table 1 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 Fixed Resource Requirement alternative). The 2023/2024 RPM BRA cleared 144,870.6 MW of unforced capacity in the RTO representing a 21.6% reserve margin. The reserve margin for the entire RTO is 20.3%, or 5.5 percentage points higher than the target reserve margin of 14.8%, when the Fixed Resource Requirement (FRR) load and resources are considered.

New Generation Resource Participation

The quantity of new Generation Capacity Resources cleared in this auction regardless of whether they had offered into a prior auction was 3,734.5 MW comprised of 3,329.7 MW from new generation units, and 404.8 MW from uprates to existing or planned generation units.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing or planned units offered in the auction and capacity clearing in the auction.

Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)

	Offered			Cleared		
LDA	Uprate	New Unit	Total	Uprate	New Unit	Total
EMAAC	7.4	95.3	**102.7**	7.4	85.7	**93.1**
MAAC**	100.8	113.1	**213.9**	100.8	103.5	**204.3**
Total RTO	554.3	1,722.1	**2,276.4**	404.8	3,329.7	**3,734.5**

*All MW Values are in UCAP Terms

**MAAC includes EMAAC

***RTO includes MAAC

**** Cleared MW values may include new units that have offered in a prior BRA and not cleared

2023/2024 RPM Base Residual Auction Results

Capacity Import Participation

The quantity of capacity imports cleared in the 2023/2024 BRA were 1,396.6 MW (UCAP) which represents a decrease of 161.4 MW from the imports that cleared in the 2022/2023 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared in the 2022/23 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2023/2024 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

	External Source Zones					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	203.7	0.0	819.4	244.3	260.6	**1,528.0**
Cleared MW (UCAP)	203.7	0.0	688.0	244.3	260.6	**1,396.6**
Resource Clearing Price ($/MW-day)	$34.13	$34.13	$34.13	$34.13	$34.13	

*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.

Demand Resource Participation

The total Unforced Capacity of DR offered into the 2023/2024 BRA was 10,116.7 MW, representing a decrease of 3.8% from the DR that offered into the 2022/2023 BRA. Of the 10,116.7 MW of total DR that offered in this auction, 8,096.2 MW cleared. The cleared DR is 715.7 MW less than that which cleared in the 2022/2023 BRA. Of the 8,096.2 MW of DR cleared in the 2023/2024 BRA, 7,919.1 MW were cleared as the annual Capacity Performance Product and 177.1 MW were cleared as the summer seasonal Capacity Performance product. Table 3A contains a comparison of the DR offered and cleared in 2022/2023 BRA & 2023/2024 BRA represented in UCAP.

Energy Efficiency Resource Participation

An EE resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the BRA for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention. All of the 5,471.1 MW of energy efficiency that offered into the 2023/2024

BRA cleared in the auction. Of the 5,471.1 MW of EE Resources that offered and cleared in the 2023/2024 BRA, 5,221.1 MW was cleared as the annual Capacity Performance Product and 250.0 MW were cleared as the summer seasonal Capacity Performance product.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2023/2024 BRA. Approximately 80.0% of the DR and 100.0% of the EE resources that were offered into the BRA cleared.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2023/2024 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and DR offered into each BRA and nominated in FRR Plans, and EE resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1, total demand side participation and cleared resources for the 2023/2024 BRA have fallen below the levels seen in the 2015/2016 BRA.

2023/2024 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2021/2022 BRA & 2023/2024 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2022/2023*	2023/2024*	Increase in Offered MW	2022/2023*	2023/2024*	Increase in Cleared MW
EMAAC	AECO	73.7	86.0	**12.3**	62.2	55.2	**(7.0)**
EMAAC/DPL-S	DPL	279.1	179.6	**(99.5)**	269.3	146.9	**(122.4)**
EMAAC	JCPL	171.8	166.3	**(5.5)**	147.8	120.5	**(27.3)**
EMAAC	PECO	414.6	449.4	**34.8**	364.4	378.4	**14.0**
PSEG/PS-N	PSEG	393.0	398.0	**5.0**	294.6	272.7	**(21.9)**
EMAAC	RECO	2.3	9.1	**6.8**	1.6	2.2	**0.6**
EMAAC Sub Total		**1,334.5**	**1,288.4**	**(46.1)**	**1,139.9**	**975.9**	**(164.0)**
PEPCO	PEPCO	336.9	238.2	**(98.7)**	322.7	175.2	**(147.5)**
BGE	BGE	186.1	211.9	**25.8**	162.6	168.4	**5.8**
MAAC	METED	260.5	280.3	**19.8**	230.7	216.2	**(14.5)**
MAAC	PENELEC	333.1	352.6	**19.5**	299.8	292.3	**(7.5)**
PPL	PPL	715.1	716.2	**1.1**	661.7	583.4	**(78.3)**
MAAC Sub Total**		**3,166.2**	**3,087.6**	**(78.6)**	**2,817.4**	**2,411.4**	**(406.0)**
RTO	AEP	1,651.5	1,623.9	**(27.6)**	1,315.3	1,292.0	**(23.3)**
RTO	APS	878.3	856.7	**(21.6)**	669.0	716.2	**47.2**
ATSI/ATSI-C	ATSI	1,124.8	1,100.1	**(24.7)**	924.1	851.5	**(72.6)**
COMED	COMED	1,760.1	1,606.6	**(153.5)**	1,511.0	1,253.2	**(257.8)**
DAY	DAY	256.5	262.4	**5.9**	210.5	209.3	**(1.2)**
DEOK	DEOK	237.0	220.3	**(16.7)**	185.1	175.4	**(9.7)**
RTO	DOM	966.8	912.2	**(54.6)**	745.5	799.1	**53.6**
RTO	DUQ	181.6	177.0	**(4.6)**	148.6	118.2	**(30.4)**
RTO	EKPC	290.2	269.9	**(20.3)**	285.4	269.9	**(15.5)**
Grand Total		**10,513.0**	**10,116.7**	**(396.3)**	**8,811.9**	**8,096.2**	**(715.7)**

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

2023/2024 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered and Cleared in the 2023/2024 BRA (in UCAP MW)

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	86.0	77.5	163.5	55.2	77.5	132.7
EMAAC/DPL-S	DPL	179.6	133.6	313.2	146.9	133.6	280.5
EMAAC	JCPL	166.3	199.1	365.4	120.5	199.1	319.6
EMAAC	PECO	449.4	383.9	833.3	378.4	383.9	762.3
PSEG/PS-N	PSEG	398.0	383.1	781.1	272.7	383.1	655.8
EMAAC	RECO	9.1	1.5	10.6	2.2	1.5	3.7
EMAAC Sub Total		**1,288.4**	**1,178.7**	**2,467.1**	**975.9**	**1,178.7**	**2,154.6**
PEPCO	PEPCO	238.2	283.1	521.3	175.2	283.1	458.3
BGE	BGE	211.9	257.0	468.9	168.4	257.0	425.4
MAAC	METED	280.3	105.2	385.5	216.2	105.2	321.4
MAAC	PENELEC	352.6	86.3	438.9	292.3	86.3	378.6
PPL	PPL	716.2	287.9	1,004.1	583.4	287.9	871.3
MAAC Sub Total**		**3,087.6**	**2,198.2**	**5,285.8**	**2,411.4**	**2,198.2**	**4,609.6**
RTO	AEP	1,623.9	602.1	2,226.0	1,292.0	602.1	1,894.1
RTO	APS	856.7	253.2	1,109.9	716.2	253.2	969.4
ATSI/ATSI-C	ATSI	1,100.1	424.8	1,524.9	851.5	424.8	1,276.3
COMED	COMED	1,606.6	961.2	2,567.8	1,253.2	961.2	2,214.4
DAY	DAY	262.4	93.5	355.9	209.3	93.5	302.8
DEOK	DEOK	220.3	157.3	377.6	175.4	157.3	332.7
RTO	DOM	912.2	652.8	1,565.0	799.1	652.8	1,451.9
RTO	DUQ	177.0	128.0	305.0	118.2	128.0	246.2
RTO	EKPC	269.9	-	269.9	269.9	-	269.9
Grand Total		**10,116.7**	**5,471.1**	**15,587.8**	**8,096.2**	**5,471.1**	**13,567.3**

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

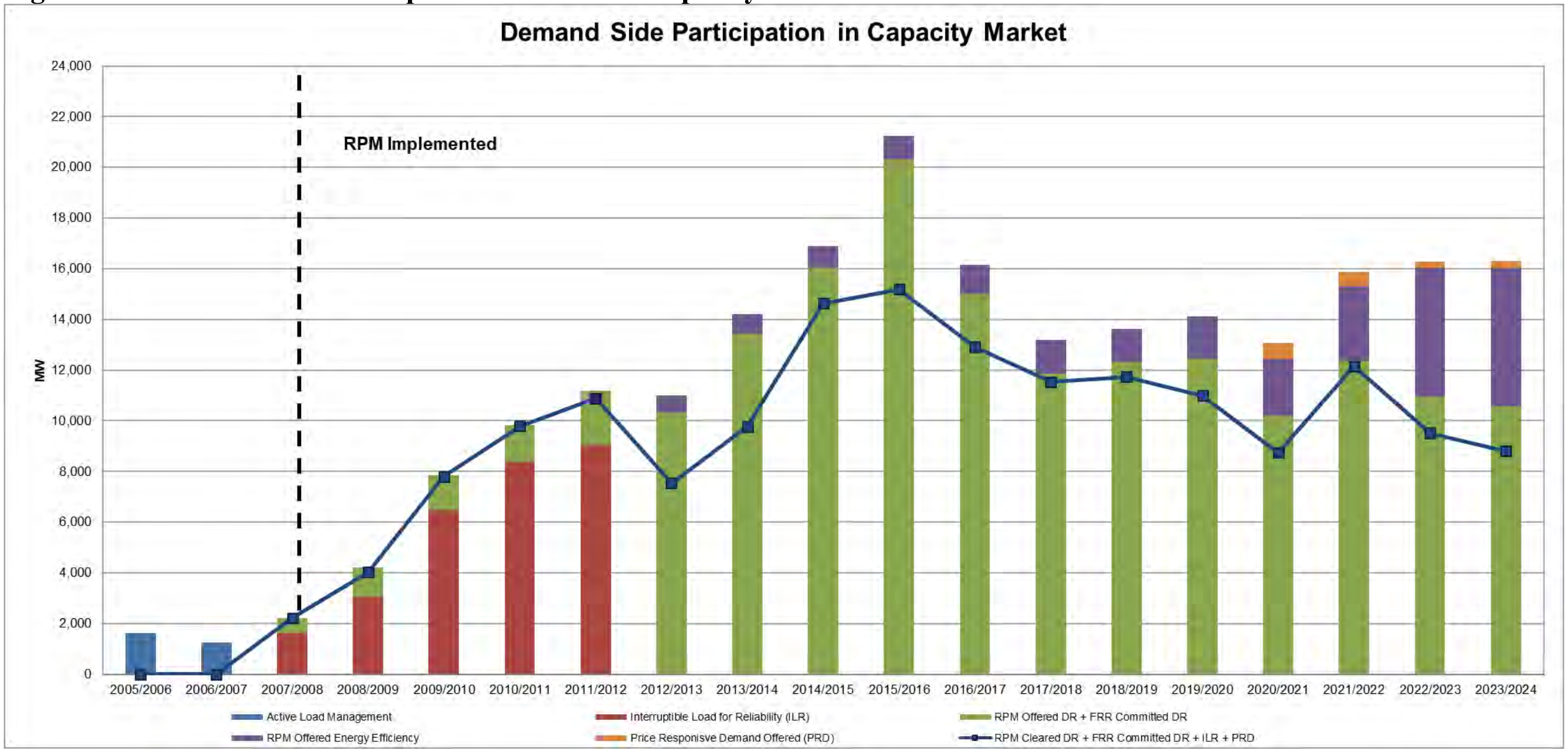
2023/2024 RPM Base Residual Auction Results

Table 3C – Breakdown of Annual and Seasonal Capacity Performance Resources by Resource Type and Season that Offered and Cleared in the 2023/2024 BRA (in UCAP MW)

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual Capacity Performance	Summer Capacity Performance	Winter Capacity Performance	Annual Capacity Performance	Summer Capacity Performance	Winter Capacity Performance
GEN	140,313.9	47.0	665.8	131,256.3	47.0	474.1
DR	9,939.6	177.1	-	7,919.1	177.1	-
EE	5,221.1	250.0	-	5,221.1	250.0	-
Grand Total	**155,474.6**	**474.1**	**665.8**	**144,396.5**	**474.1**	**474.1**

2023/2024 RPM Base Residual Auction Results

Figure 1 – Demand Side Participation in the PJM Capacity Market



Renewable Resource Participation

1,294.1 MW of wind resources cleared the 2023/2024 BRA as compared to 1,728.1 MW of wind resources that cleared the 2022/2023 BRA. Of the 1,294.1 MW of wind resources cleared in the 2023/2024 BRA, 820.0 MW were cleared as the annual Capacity Performance Product and 474.1 MW were cleared as the winter seasonal Capacity Performance product. The nameplate capability of wind resources that cleared in the 2023/2024 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,075.1 MW, which is 443.2 MW less than the 8,518.3 MW of wind energy nameplate capability that cleared in the 2022/2023 BRA.
1,868.4 MW of solar resources cleared the 2023/2024 BRA as compared to 1,511.6 MW of solar resources that cleared the 2022/2023 BRA. Of the 1,868.4 MW of solar resources cleared in the 2023/2024 BRA, 1,821.4 MW were cleared as the annual Capacity

Performance Product and 47 MW were cleared as the summer seasonal Capacity Performance product. The nameplate capability of solar resources that cleared in the 2023/2024 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 4,414.1 MW, which is 1,171.3 MW greater than the 3,242.8 MW of solar energy nameplate capability that cleared in the 2022/2023 BRA.

Price Responsive Demand Participation

A total Nominal PRD Value of 235 MW was elected and committed in the 2023/2024 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing 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 which indicates the Nominal PRD Value in MWs 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. As shown in the 2023/2024 Planning Parameters, 235 MW of PRD across the RTO has elected to participate in the 2023/2024 BRA: 87 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 38 MW in the EMAAC LDA (with 15.4 MW located in the DPL-South 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.

LDA Results

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 and DEOK were modeled as LDAs in the 2023/2024 RPM Base Residual Auction. The MAAC, BGE and DPL-South LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained

2023/2024 RPM Base Residual Auction Results

LDA and the immediate higher level LDA. Table 4 contains a summary of the clearing results in the LDAs from the 2023/2024 RPM Base Residual Auction.

Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

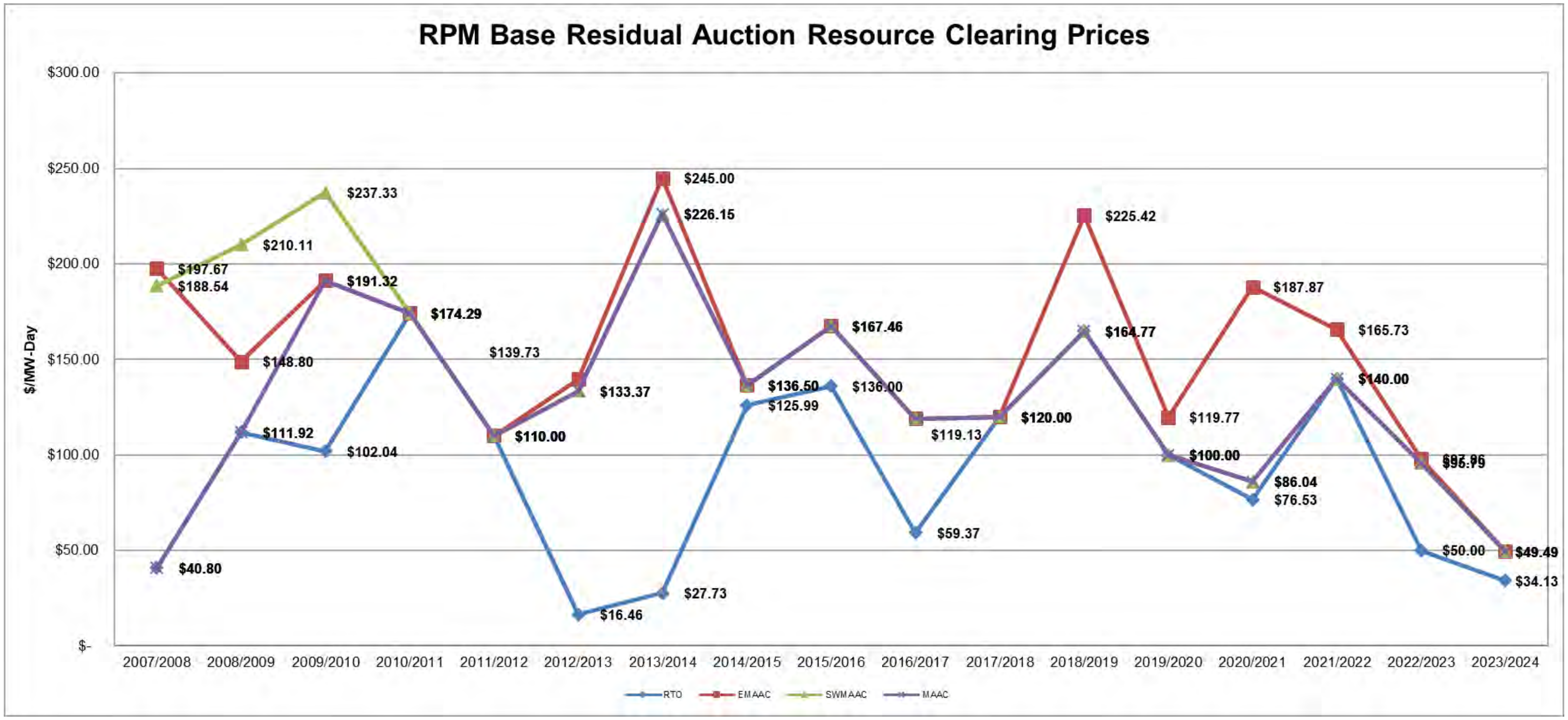
Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED	DAY	DEOK
Offered MW (UCAP)*	156,614.5	67,876.7	8,940.2	3,597.7	2,892.3	30,990.7	1,384.7	5,969.7	3,391.4	10,043.2	1,959.5	10,518.5	29,018.2	1,321.9	2,134.2
Cleared MW (UCAP)**	144,870.6	62,929.4	8,374.9	3,508.7	2,416.0	30,097.5	1,324.0	5,839.5	3,344.6	9,531.4	1,899.9	10,113.7	25,358.3	1,261.6	1,964.5
System Marginal Price	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13	$34.13
Locactional Price Adder***	$0.00	$15.36	$0.00	$0.00	$20.46	$0.00	$20.46	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RCP for Capacity Performance Resources	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$69.95	$49.49	$49.49	$34.13	$34.13	$49.49	$34.13	$34.13	$34.13

* 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 w ithin the LDA
*** Locational Price Adder is w ith respect to the immediate parent LDA

Since the MAAC, BGE, and DPL-South LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2023/2024 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.

2023/2024 RPM Base Residual Auction Results

Figure 2 – Base Residual Auction Resource Clearing Prices



* 2014/2015 through 2023/2024 Prices reflect the Annual Resource Clearing Prices.

2023/2024 RPM Base Residual Auction Results

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2023/2024 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 205,607.8 MW of installed capacity was eligible to be offered into the 2023/2024 Base Residual Auction, with 1,601.2 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2023/2024 auction decreased slightly from that of the previous auction and FRR commitments increased by 203.6 MW from the 2022/2023 Delivery Year to 33,500.7 MW.

A total of 160,873.6 MW of capacity was offered into the Base Residual Auction. This is a decrease of 11,332.9 MW from that which was offered into the 2022/2023 BRA. A total of 44,734.2 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, (3) having been excused from offering into the auction or (4) are not required to offer into the auction and elected to not offer into the auction. Resources were excused from the must offer requirement are generally for the following reasons: approved retirement requests, resources categorically exempt from the Capacity Performance must-offer requirement, resources which received an exemption from the must-offer or Capacity Performance must-offer requirement and excess capacity owned by an FRR entity.

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2023/2024 RPM Base Residual Auction Results

Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

	RTO[1]															
Auction Supply (all values in ICAP)	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012[2]**	**2012/2013**	**2013/2014[3]**	**2014/2015[4]**	**2015/2016[5]**	**2016/2017[6]**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4	199,375.5	207,559.1	208,098.0	202,477.4	203,300.6	207,579.6	207,555.1	211,625.2	207,339.8	204,006.6
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1	7,620.2	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
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**	**206,995.7**	**212,208.8**	**216,510.2**	**208,778.3**	**209,025.2**	**212,401.0**	**212,995.6**	**216,350.2**	**208,988.9**	**205,607.8**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5	1,230.1	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
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1	33,612.7	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
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7	3,255.2	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	7,826.4	8,923.8	1,960.0	9,714.6
Total Eligible RPM Capacity: Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**	**38,098.0**	**25,929.6**	**25,319.4**	**21,304.6**	**19,454.8**	**18,158.0**	**23,077.8**	**23,901.0**	**36,782.4**	**44,734.2**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**	**192,449.2**	**172,206.5**	**160,873.6**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1	153,048.1	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
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7	15,043.1	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
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4	806.5	907.8	1,112.6	1,289.0	1,205.5	1,517.4	2,062.9	2,713.8	4,656.4	5,019.7
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**	**192,449.2**	**172,206.5**	**160,873.6**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[1]RTO numbers include all LDAs.
[2]All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.
[3]2013/2014 includes ATSI zone and generation
[4]2014/2015 includes Duke zone and generation
[5]2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
[6]2016/2017 includes EKPC zone

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR) and Demand Resource Factor, when applicable, for the Delivery Year.

In UCAP terms, a total of 156,614.5 MW were offered into the 2023/2024 BRA, comprised of 141,026.7 MW of generation capacity, 10,116.7 MW of capacity from DR, and 5,471.1 MW of capacity from EE resources. Of those offered, a total of 144,870.6 MW of capacity was cleared in the BRA.

Of the 144,870.6 MW of capacity that cleared in the auction, a total of 131,777.4 MW cleared from Generation Capacity Resources, 8,096.2 MW cleared from DR, and 5,471.1 MW cleared from EE resources, of which, 474.1 MW cleared as matched seasonal CP resources. Capacity that was offered but not cleared in the BRA Auction will be eligible to offer into the Third Incremental Auction for the 2023/2024 Delivery Year.

Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

	RTO*															
Auction Results	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8	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
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6	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
EE Offered	-	-	-	-	652.7	756.8	831.9	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
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**	**178,587.7**	**184,380.0**	**178,838.5**	**179,891.2**	**185,539.5**	**183,351.5**	**186,504.8**	**167,698.4**	**156,614.5**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2	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
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	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
EE Cleared	0.0	0.0	0.0	0.0	568.9	679.4	822.1	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
Total Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**	**164,561.2**	**169,159.7**	**167,003.7**	**166,836.9**	**167,305.9**	**165,109.2**	**163,627.3**	**144,477.3**	**144,870.6**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6	14,026.5	15,220.3	11,834.8	13,054.3	18,233.6	18,242.3	22,877.5	23,221.1	11,743.9

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

***Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

***Starting 2020/2021: Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2023/2024 BRA. A total of 5,217.9 MW of incrementally new generation capacity in PJM was available for the 2023/2024 BRA. This incrementally new generation capacity includes new Generation Capacity Resources and capacity upgrades to existing and planned Generation Capacity Resources. The increase is offset by generation capacity deratings on existing Generation Capacity Resources of 8,582.4 MW. The quantity of DR decreased by 395.7 MW and EE increased by 363.3 MW of installed capacity as compared to the 2022/2023 BRA.

Table 7 also illustrates the total amount of resource additions and reductions over 16 Delivery Years since the implementation of the RPM construct. Over the period covering the first 17 RPM BRAs, 73,740.9 MW of new generation capacity was added, which was partially offset by 64,405.2 MW of capacity de-ratings or retirements over the same period. Additionally, 9,720.0 MW of new DR and 5,019.7 MW of new EE resources were offered over the course of the sixteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last 17 RPM auctions was 24,075.4 MW.

2023/2024 RPM Base Residual Auction Results

Table 7 – Incremental Capacity Resource Additions and Reductions to Date

	RTO*																	
Capacity Changes (in ICAP)	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014[1]**	**2014/2015[2]**	**2015/2016**	**2016/2017[3]**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**	**Total**
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	1,737.5	1,582.8	8,207.0	6,806.0	6,973.3	5,055.6	6,327.8	4,257.5	1,196.9	10,578.5	5,217.9	67,785.3
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,253.9	-1,924.1	-1,550.1	-6,432.6	-4,992.0	-9,760.1	-3,620.8	-2,923.1	-3,016.1	-1,691.7	-14,491.6	-8,582.4	-64,405.2
Net Increase in Demand Resource	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	2,514.4	4,200.5	-5,310.7	-3,077.7	-82.4	86.4	-1,811.4	1,864.1	-1,234.0	-395.7	9,720.0
Net Increase in Energy Efficiency	0.0	0.0	0.0	0.0	0.0	632.3	101.1	73.1	101.3	204.8	176.4	-83.5	311.9	545.5	650.9	1,942.6	363.3	5,019.7
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1503.1**	**3973.3**	**7,210.0**	**2,907.8**	**2,620.2**	**6,076.2**	**-3,291.9**	**-5,688.1**	**1,268.9**	**3,803.0**	**-24.5**	**2,020.2**	**-3,204.5**	**-3,396.9**	**18,119.8**

* RTO numbers include all LDAs
** Values are with respect to the quantity offered in the previous year's Base Residual Auction.
1) Does not include Existing Generation located in ATSI Zone
2) Does not include Existing Generation located in Duke Zone
3) Does not include Existing Generation located in EKPC Zone

Table 7A provides a further breakdown of the generation increases and decreases for the 2023/2024 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2023/2024 Delivery Year

LDA Name	Increases	Decreases
EMAAC	126.6	(942.4)
MAAC*	512.5	(3,535.1)
Total RTO**	**5,217.9**	**(8,582.4)**

All Values in ICAP terms
*MAAC includes EMAAC
**RTO includes MAAC

Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant increase in generating capacity from combined cycle, and solar in the 2023/2024 BRA as compared to the 2022/2023 BRA. The capacity offered in the 2023/2024 BRA resulted from both new generating resources and uprates to existing resources. As shown in Figure 3, the largest growth remains in combined cycle plants.

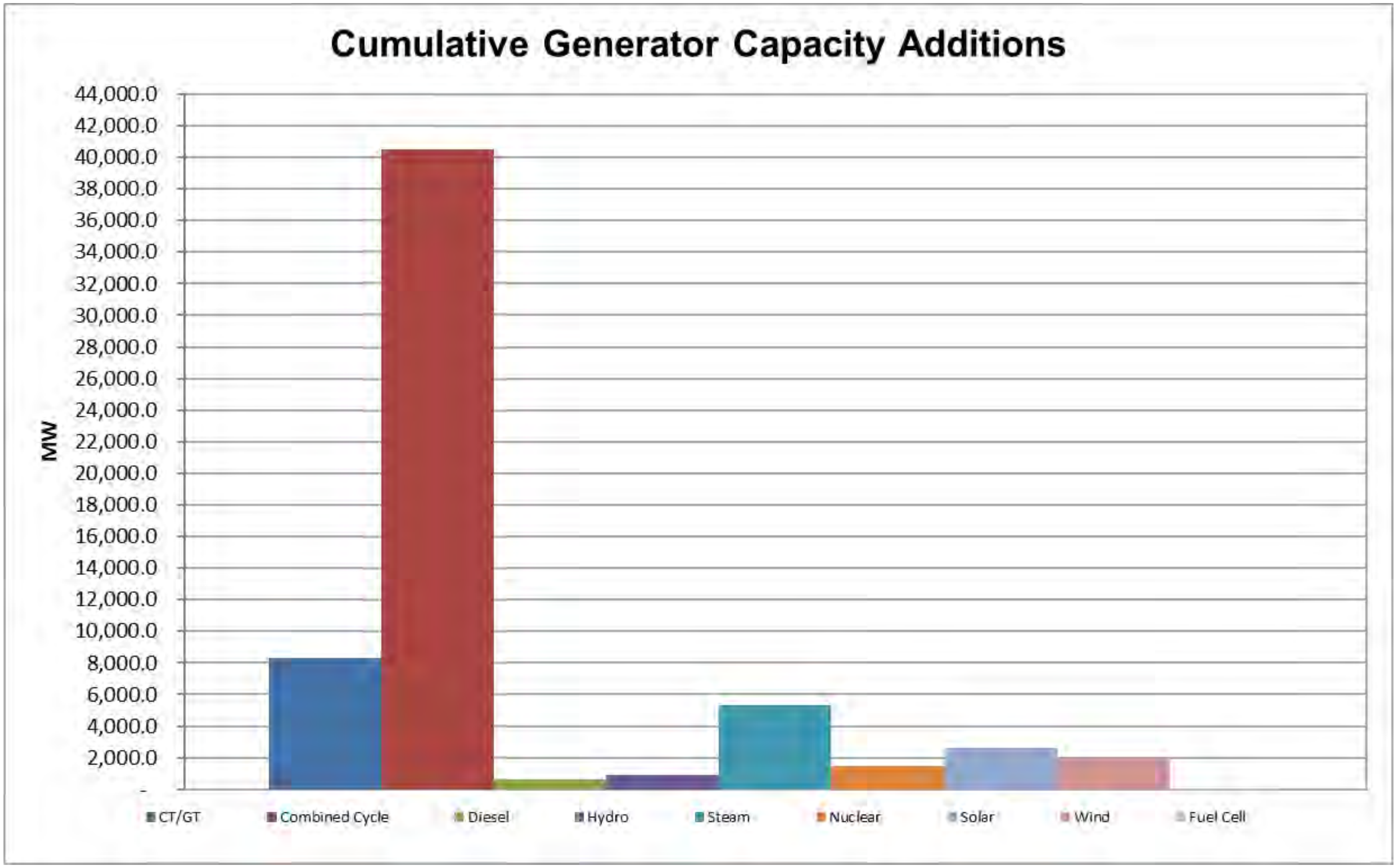
2023/2024 RPM Base Residual Auction Results

Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2023/2024

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Fuel Cell	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3						19.0
	2008/2009			27.0					66.1		93.1
	2009/2010	399.5		23.8		53.0					476.3
	2010/2011	283.3	580.0	23.0					141.4		1,027.7
	2011/2012	416.4	1,135.0			704.8		1.1	75.2		2,332.5
	2012/2013	403.8		7.8		621.3			75.1		1,108.0
	2013/2014	329.0	705.0	6.0		25.0		9.5	245.7		1,320.2
	2014/2015	108.0	650.0	35.1	132.9			28.0	146.6		1,100.6
	2015/2016	1,382.5	5,914.5	19.4	148.4	45.4		13.8	104.9	30.0	7,658.9
	2016/2017	171.1	4,994.5	38.3		24.0		32.1	54.3		5,314.3
	2017/2018	131.0	5,010.0	124.8	6.0	90.0		27.0			5,388.8
	2018/2019	1,032.5	2,352.3	29.9				82.8	127.1		3,624.6
	2019/2020	167.0	6,145.0	29.9				152.3	73.0		6,567.2
	2020/2021		2,410.0	26.3	4.0			94.3	30.2		2,564.8
	2021/2022			19.9				237.8	65.7		323.4
	2022/2023	14.0	5,626.8					1,440.8	345.1		7,426.7
	2023/2024		1,323.0					401.9	34.5		1,759.4
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0					47.0
	2008/2009					131.0					131.0
	2009/2010										-
	2010/2011	160.0		10.7							170.7
	2011/2012	80.0				101.0					181.0
	2012/2013										-
	2013/2014										-
	2014/2015			9.0							9.0
	2015/2016										-
	2016/2017					21.0					21.0
	2017/2018					991.0					991.0
	2018/2019										-
	2019/2020										-
	2020/2021										-
	2021/2022										-
	2022/2023										-
	2023/2024										-
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0				536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4				500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5		796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3				577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7		1,062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8		785.5
	2013/2014	56.4	59.0	0.3		215.0	47.0		39.6		417.3
	2014/2015	104.9		0.5	41.5	138.6	107.0	7.1	73.6		473.2
	2015/2016	216.8	72.0	4.7	15.7	63.4	149.2	2.2	24.1		548.1
	2016/2017	436.6	420.0	3.3	7.4	484.3	102.6	1.7	14.8		1,470.7
	2017/2018	71.9	212.5	5.1	105.9	64.8	11.0	0.4	2.1		473.7
	2018/2019	33.4	548.0	2.4	22.9	11.9	79.3	-	14.9	-	712.8
	2019/2020	29.3	72.5	3.9	5.2	65.3	-	-	46.8	-	223.0
	2020/2021	9.3	588.8	1.2	4.6	5.7		1.0	14.7		625.3
	2021/2022	100.2	549.9	7.1	3.6	91.9	-	24.2	18.4	-	795.3
	2022/2023	674.1	316.4	7.7	-	334.9	99.0	50.0	10.3	-	1,492.4
	2023/2024	434.0	99.0			16.0		17.1	2.2		568.3
	Total	8,337.6	40,500.1	589.3	894.4	5,308.3	1,501.3	2,625.1	1,928.4	30.0	61,714.5

2023/2024 RPM Base Residual Auction Results

Figure 3: Cumulative Generation Capacity Increases by Fuel Type



2023/2024 RPM Base Residual Auction Results

Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2023/2024 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 16,422.3 MW of cleared UCAP in the 2023/2024 BRA which equates to 17,491.8 MW of ICAP Offered.

Table 9 – Changes to Generation Retirement Decisions since Commencement of RPM in 2007/2008

	RTO*	
Generation Resource Decision Changes	**ICAP Offered**	**UCAP Cleared**
Withdraw n Deactivation Requests	13,606.9	13,423.2
Postponed or Cancelled Retirement	3,153.5	2,286.7
Reactivation	731.4	712.4
Total	**17,491.8**	**16,422.3**

RPM Impact to Date

As illustrated in Table 5, for the 2023/2024 auction, the capacity exports were 1,540.9 MW and the offered capacity imports were 1,601.2 MW. The difference between the capacity imports and exports results is a net capacity import of 60.3 MW. In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 60.3 MW. Therefore, RPM's impact on PJM capacity interchange is 2,676.3MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2023/2024 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2023/2024 compared to what would have happened absent this implementation is 95,253.0 MW.

2023/2024 RPM Base Residual Auction Results

Table 10 shows the details on RPM's impact to date in ICAP terms.

Table 10 – RPM's Impact to Date

Change in Capacity Availability	Installed Capacity MW
New Generation	48,105.5
Generation Upgrades (not including reactivations)	12,058.3
Generation Reactivation	1,550.7
Forward Demand and Energy Efficiency Resources	14,739.7
Cleared ICAP from Withdrawn or Cancelled Retirements	16,100.5
Net increase in Capacity Imports	2,698.3
Total Impact on Capacity Availability in 2023/2024 Delivery Year	**95,253.0**

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2023/2024 RPM BRA clearing prices relative to 2022/2023 BRA clearing prices are provided below, separated out by changes to the demand-side and supply-side of the market.

Changes that impacted the Demand Curve:

- The 2023/2024 RTO Reliability Requirement was 163,166 or only 103 MW lower than in 2022/2023.
- 235 MW of PRD across the RTO has elected to participate in the 2023/2024 BRA. This is only 5 MW more than the amount that participated in the 2022/2023 BRA.
- The Net CONE increased in the RTO and for all of the modeled LDAs, except for BGE where it decreases. The Net CONE of the RTO increased by 5.6% and the increased in LDA Net CONE values ranged from -3.1% for the BGE LDA to 15% for the COMED LDA.

2023/2024 RPM Base Residual Auction Results

Changes that impacted the Supply Curve:

- The default MSOC was eliminated and all units subject to mitigation were required to use unit specific netEAS offset values.
- Significantly less resources were subject to MOPR in the 2023/2024 BRA, because of the implementation of the new MOPR rules, relative to the 2022/2023 BRA.
- New generation capacity of 3,734.5 MW cleared in the BRA, which comprised of 3,329.7 of new generation and 404.8 MW of uprates.
- Intermittent Resource and storage (ELCC Resources) capacity accreditation was based on ELCC methodology.

Gross Avoidable Costs for Existing Generation

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TABLE OF CONTENTS

Executive Summary iii

I. Introduction 6
- A. Purpose of ACRs and this Analysis 6
- B. Analytical Approach 7

II. Selection of Plant Types within PJM Fleet 10

III. Gross Costs for Existing Generation 11
- A. Multi-Unit Nuclear Plants 11
- B. Single-Unit Nuclear Plants 16
- C. Coal Plants 19
- D. Natural Gas-Fired Combined-Cycle Plants 24
- E. Simple-Cycle Combustion Turbines 30
- F. Oil- and Gas-Fired Steam Turbines 35
- G. Onshore Wind Plants 38
- H. Large Scale Solar Photovoltaic Plants 42

Executive Summary

Starting with the 2022/23 Delivery Year, PJM Interconnection, L.L.C. (PJM) is required under the Open Access Transmission Tariff (OATT or tariff) to update Default Gross Avoidable Cost Rates (ACRs) every four years.[1] This study informs PJM's filing by developing updated gross cost estimates for various existing generation types.

PJM uses Default Gross ACRs (minus unit-specific net energy and ancillary services (E&AS) revenues) to determine default offer thresholds for mitigating market power in its capacity market. For several years, the Default Gross ACRs were used only for mitigating so-called "buyer-side" market power; capacity resources that were subject to the Minimum Offer Price Rule (MOPR) were subject to default offer floors and could offer at lower prices only if accepted through a unit-specific review of actual costs.[2] However, in March 2021, the Federal Energy Regulatory Commission (FERC) ordered PJM to expand the application of Default ACRs to its mitigation of supplier market power, after finding that the existing offer caps were excessive.[3] Any resources subject to Market Seller Offer Caps (MSOCs) could now offer above the default ACRs only by demonstrating higher costs through unit-specific reviews. Thus, PJM's updated Default Gross ACRs will be used for mitigating supplier market power (via MSOC) as well as for MOPR purposes in PJM's Base Residual Auctions for 2026/27 and the following three delivery years.

To conduct this update of the Default ACRs, PJM retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to analyze the gross avoidable costs for several types of existing generation. We have done so based on bottom-up analysis of costs for representative plants, drawing on data and the combined experience of Brattle and S&L. We also solicited and incorporated stakeholder input through three rounds of presentations before the Market Implementation Committee (MIC) between October and December.

Our approach recognizes that existing generation resources vary considerably in their characteristics and costs, both across resource types and even within each type. This variability

1 PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14(h-2)(3)(B).

2 See Minimum Offer Price Rule (MOPR)—Attachment DD § 5.14(h-2).

3 See Market Seller Offer Cap (MSOC)—Attachment DD § 6.4.

must be considered in developing coherent "types" and in developing default offer thresholds for each, trading off the risks of under-mitigation against the risks of over-mitigation and/or a burdensome amount of unit-specific reviews.

To inform PJM's determination of a single Default Gross ACR for each resource type, we reviewed the range of characteristics of resources in the PJM market and identified the primary cost drivers among those characteristics for each resource type. We identified for each resource type the characteristics of a "representative plant" that is widely representative of most of the fleet and reflects the median MW in terms of cost structure. We also identified the characteristics for "representative low-cost" and "representative high-cost" plants to inform the range of costs PJM may see for each type of existing generation resource.

Given the assumed characteristics, we then estimated the avoidable gross costs of the representative plants to inform PJM's filing of Default Gross ACRs. The cost estimates are based on S&L analysis of FERC Form 1 data and the Nuclear Energy Institute's (NEI's) "Nuclear Costs in Context" study and its own proprietary database, and Brattle analysis.

We also provide estimates for the Variable Operation and Maintenance (VOM) costs as a benchmark to inform PJM's E&AS net revenue analysis when determining Net ACRs. The classification of costs categories as gross versus variable align with PJM's current market rules concerning the costs that are includable in the Gross ACRs versus those that can be included in cost-based energy offers (and thus accounted for in the E&AS revenue component of Net ACRs). Accordingly, the costs of major maintenance and overhauls directly related to the production of electricity are included in variable costs as a "maintenance adder."

Table ES-1 below shows the resulting gross costs for each existing generation resource type, expressed in 2022 dollars per-megawatt (MW) of nameplate capacity. Variable costs are presented separately, within the body of this report. Note that throughout this report, our results are presented as "gross costs" rather than "Gross ACRs" because the formal term reflects a tariff rate filed by PJM and approved by FERC, and our study only informs those rates.

TABLE ES-1: EXISTING GENERATION GROSS COSTS
(IN 2022 DOLLARS PER NAMEPLATE MW PER DAY)

Resource Type	Representative Plant $/MW-day
Multi-unit Nuclear	**$537**
Single-unit Nuclear	**$591**
Coal	**$94**
Natural Gas CC	**$113**
Simple Cycle CT	**$52**
ST O&G	**$64**
Onshore Wind	**$147**
Solar PV	**$70**

I. Introduction

A. Purpose of ACRs and this Analysis

In the presence of structural market power in capacity markets, PJM as market operator needs to be able to mitigate offers outside of reasonable bounds of competitive levels. Concerns surround both supplier market power and buyer market power. Supplier market power is deemed a threat where jointly-pivotal market sellers fail the Three Pivotal Supplier ("TPS") test, which all typically do.[4] Under such circumstances, resource offers would be subject to Market Seller Offer Caps (MSOC). Buyer market power—in the form of resources being offered at artificially lower prices—is deemed a concern under special circumstances and applicable resources would be subject to the Minimum Offer Price Rule (MOPR). MOPR applicability has recently been narrowed after much litigation.[5]

PJM will approach both instances by setting default offer thresholds for various resource types, such that higher-priced offers on MSOC-applicable resources could trigger a unit-specific review to consider setting a higher unit-specific MSOC; lower-priced offers on MOPR-applicable resources could trigger a unit-specific review to set a lower unit-specific MOPR. Default thresholds will be determined by a generic resource type-specific Gross Avoidable Cost Rate (ACR) minus resource-specific net revenues from energy and ancillary services markets (net E&AS offset).

Until recently, MSOCs were set uniformly across all existing resources, given by the Net Cost of New Entry (Net CONE) times an average "balancing ratio" of 85% based on an assumed number of Performance Assessment Intervals (PAIs). However, in March 2021, the Federal Energy Regulatory Commission (FERC) found the MSOCs to be unjust and unreasonable.[6] FERC found those rates to be too high, due to an unrealistically high estimate of the number of expected PAIs. FERC ordered PJM to use more specific Avoidable Cost Rates, as it uses for MOPR, and as it had used for MSOC purposes prior to the implementation of Capacity Performance in 2016.

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4 PJM, Market Seller Offer Cap (MSOC) Reform, February 28, 2022.

5 Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000, September 29, 2021.

6 Federal Energy Regulatory Commission, Order Granting Complaints and Ordering Additional Briefing, Docket Nos. EL 19-47-000 and EL 19-63-000, March 18, 2021.

Thus, this updated ACR study will be used for both purposes, in fulfillment of PJM's requirement to periodically update its Default Avoidable Cost Rates (ACRs) every four years.[7] The last such study was conducted by us in 2020, but future studies will be conducted every four years.

For this study, PJM requested that we estimate Gross Costs for existing generation resource types. The types would be defined to span most of the PJM fleet, where each type includes similar resources with similar cost structures; types would not be defined for resource classes that exhibit highly idiosyncratic and varying avoidable costs. For each type, we were asked to develop bottom-up cost estimates of the gross fixed costs for a "representative" plant, For informational purposes we also provided a "representative low" and "representative high" for lower and higher-cost sub-groups within each type. Additionally, PJM requested that we determine the Variable Operation and Maintenance (VOM) costs for each resource type for informational purposes to aide PJM in determining E&AS revenues.

As PJM applies the study results to determine default offer thresholds, it will need to balance the need to mitigate the exercise of market power against the administrative burden and risks of over-mitigation. Over-mitigation is possible due to information asymmetries between PJM and capacity sellers, even in unit-specific reviews. That could result, for example, in a resource's MSOC being set below its true competitive costs—which could discourage participation in the market. Over-mitigation can be avoided in part by setting default MSOCs reasonably high so that many resources would not need a unit-specific review to justify higher offers; and by setting default MOPRs reasonably low for symmetrical reasons.

B. Analytical Approach

To calculate the gross default costs we first identified types that span most of the installed capacity in the PJM footprint and have sufficiently little variation of gross fixed costs within the type. We then analyzed the fleet and identified defining characteristics of the median plant by capacity; and then calculated the gross costs that would be avoided if such a plant retired. The calculations are consistent with PJM's tariff for the scope of costs allowable in Gross ACRs.

For the definition of types, we received an initial list from PJM that was based on the previously identified types from the 2020 Gross ACR study. These types were chosen to span a large

[7] PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 5 Capacity Resource Commitment, Section 5.14(h-2)(3)(B).

portion of the overall PJM fleet and such that each type is coherent and has common cost characteristics within it. We then iterated upon the defined types with PJM and market stakeholders and included one additional type due to stakeholder feedback. A small remaining portion of the fleet that we did not characterize as "types" with a Default Gross ACR had more idiosyncratic cost characteristics among individual plants (e.g., due to older, non-standard technology) so did not lend themselves well to defining a standardized estimate of costs; absent a Gross ACR, these plants will have to rely on unit-specific reviews for nonzero capacity offers.

For each defined resource type, we identified the characteristics of a "representative plant" that is widely representative of the individual plants within that type. The "representative plant" standard that we agreed on with PJM staff and reviewed with stakeholders was a median for the population of PJM plants in each type, with the median being defined on a capacity (MW) basis. Since it would have been impractical to develop cost estimates for every plant in the fleet, we instead identified the median plant as one with median values of the main cost drivers: (1) the unit size; (2) the plant age and technology vintage; (3) the plant location in PJM; and (4) the configuration of the units, including pollution controls. We then estimated the costs for such a plant as described below.

While we agreed with PJM and stakeholders that the representative plant would be used to determine the Default Gross ACRs, we also sought to inform the range of costs PJM might see for each type. We thus defined a "representative high-cost" and a "representative low-cost" plant for each type, considering the range of characteristics and especially clusters thereof. This was unnecessary, however, for single-unit nuclear plants since the population consists of only two plants.

Given the assumed representative characteristics, we then estimated the costs of the representative plants to inform the gross costs, as well as the variable O&M costs to inform PJM's net E&AS analysis. Gross costs reflect the fixed costs of operating an existing generation resource for an additional year that could be avoided if the plant retires.[8] Our cost estimates for most types of thermal plants are based on S&L's regression analyses of FERC Form 1 filings for plants with characteristics similar to the representative plants for each resource type, benchmarked and adjusted using confidential cost estimates from S&L's project database. For nuclear plants, where FERC Form 1 submissions were deemed inconsistent, we relied on NEI's

[8] Given the very limited prevalence of "mothballing," meaning a unit that does not operate for the Delivery Year but is maintained in a state such that it may be brought back into service in a future year, we only consider the costs that are avoidable if a unit retires.

latest "Nuclear Costs in Context" study, with adjustments to reflect the representative plant. For wind and solar plants, for which FERC Form 1 data is sparse, we relied on S&L's extensive project database.

For most types, property taxes and insurance constitute a relatively small fraction of total cost, but they are less straightforward to quantify uniformly, and we have refined our approach since our 2020 study and over the course of this study based on stakeholder feedback. Our approach to estimating these costs varies by resource type given data availability, and is described under each type presented below.

One aspect of this study that required careful consideration was to distinguish which costs to include in the gross costs and which to consider as variable costs. Only the gross costs would determine resource types' Default Gross ACRs, while variable costs would presumably be accounted for in resources' Default Net ACRs for capacity offer mitigation purposes if generators include them in their cost-based energy offers. To avoid double counting any such costs, it is important to categorize these costs consistently with PJM's rules regarding energy market offers. We followed PJM guidance regarding its tariff and operating agreements.[9] Among other cost categories, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder that includes activities such as repair, replacement, and major inspection.[10] Therefore, consistent with tariff, our estimated gross costs include Fixed Capital Costs and Fixed Operation & Maintenance (FOM) costs but not major maintenance costs for systems directly related to electric production. In the case of nuclear plants, however, we provide an indicative estimate of the gross costs with major maintenance included for informational purposes in the hypothetical case if PJM were to determine that major maintenance should be included in the Gross ACR

9 PJM staff reviewed the specifications in their tariff and operating agreements, and provided guidelines to follow based on their interpretation. The PJM Open Access Transmission Tariff (OATT) Attachment DD section 6.8(c) specifies that "[v]ariable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate." Section 6.8 also lists eleven components of Avoidable Cost Rates. The PJM Operating Agreement Schedule 2 further specifies the expenses allowed to be included in the maintenance adder as a variable cost as part of energy offers, rather than in the Gross ACR: "Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses." Schedule 2 states that "preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, compressed air, closed cooling water, heat tracing/freeze protection, and water treatment" cannot be included in cost-based energy offers, and thus are included in the Gross ACR. We understand that PJM interprets this to mean that all maintenance costs for systems directly related to electric production can be included in the operating costs maintenance adder for cost-based energy offers, and thus are excluded from the Avoidable Cost Rates. See PJM, PJM Open Access Transmission Tariff, Attachment DD, Section 6 Market Power Mitigation, Section 6.8(c).

10 PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

and adapts its tariff accordingly. For the remainder of plant types, given PJM's guidance, we identify the types of maintenance costs included in the gross costs and those included in the variable cost maintenance adder, and estimate the costs of each accordingly, as reported below.

II. Selection of Plant Types within PJM Fleet

Based on PJM input, the approach described above, and stakeholder feedback, we defined the following resource types for estimating gross costs:

- Multi-unit nuclear
- Single-unit nuclear
- Coal
- Natural gas-fired combined-cycle turbines (NG CC)
- Simple-cycle combustion turbines (Simple Cycle CT), previously limited to natural gas combustion turbines
- Oil and gas-fired steam turbines (ST O&G), new type based on stakeholder feedback
- Onshore wind
- Large-scale (>1 MW) solar photovoltaic plants (Solar PV)

These types are similar to those in the 2020 ACR study, but expanded based on stakeholder feedback. We added an oil and gas-fired steam turbine type and amplified the simple-cycle combustion turbine type to include oil peaker plants as well as gas plants compared to the 2020 ACR determination.[11] Table 1 shows a breakdown of the current capacity of the PJM fleet. The chosen resource types combined cover about 94% of the entire PJM fleet.

[11] Newell, et al., Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency, March 17, 2020 ("2020 Gross ACR Study").

TABLE 1: PJM FLEET CAPACITY BY PLANT TYPE

Plant Type	Total MW (Summer ICAP)	% of Total PJM Capacity	Recommendation
NGCC	**55,828**	**28%**	**Included**
Coal	**41,554**	**21%**	**Included**
Nuclear	**32,556**	**16%**	**Included**
Simple Cycle CT	**28,496**	**14%**	**Included**
Wind	**9,911**	**5%**	**Included**
ST O&G	**9,240**	**5%**	**Included**
Solar	**7,790**	**4%**	**Included**
Pumped Storage	5,243	3%	Unit-specific review
Hydro	3,319	2%	Unit-specific review
Other	3,427	2%	Unit-specific review
PJM Total Installed Capacity	**197,364**	100%	

Notes and Sources: ABB, Energy Velocity Suite.

The remaining resource types, for which gross costs were not determined, represent a small percentage of PJM's capacity. These resource types either have very few plants in their population and/or highly idiosyncratic costs, making them better candidates for unit-specific reviews rather than a standardized ACR.

III. Gross Costs for Existing Generation

A. Multi-Unit Nuclear Plants

Most nuclear plants in PJM have multiple units installed at the same site. In total, there are currently 14 multi-unit nuclear plants operating in the PJM footprint. The capacity of multi-unit nuclear plants in PJM are mostly in the range of 1,750–2,500 MW, and in most cases these plants are 30–50 years old. There are six states in PJM with nuclear plants, with the most located in Illinois and Pennsylvania.[12] Figure 1 below summarizes the age, size, and locations of these plants.

[12] The Hope Creek plant in New Jersey is classified as a multi-unit plant because it is co-located with the Salem nuclear plant. Figure 1 shows them as if they were a single 3-unit plant.

Based on our experience estimating costs for nuclear plants, the most significant cost drivers for nuclear plants are the plant size and number of units, reactor type such as the boiling water reactor (BWR) versus the pressurized water reactor (PWR), the location (which impacts property taxes and operating costs), the business model (merchant generation vs. regulated cost-of-service generation), and the operator's fleet size.

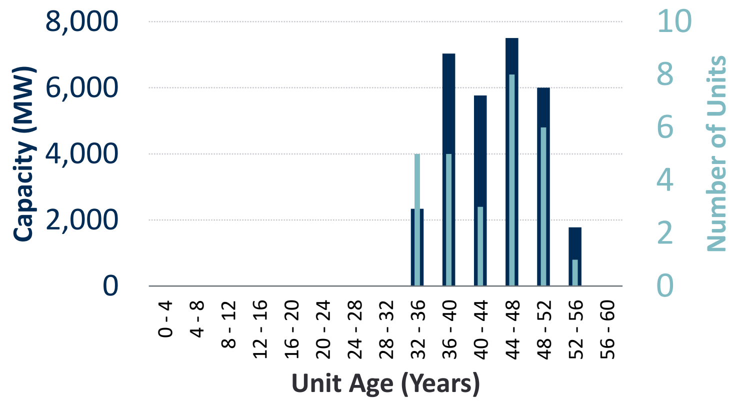
Representative Multi-Unit Nuclear Plant Characteristics

To choose a representative multi-unit nuclear plant we first determined the median plant size of the most frequent size bin of the nuclear fleet, which was between 2,200 MW to 2,400 MW as shown in Figure 1, Panel (B). We then filtered the multi-unit fleet data by this size bin (2,200 MW to 2,400 MW) and compared the median age of the filtered population to the median age of the unfiltered total multi-unit nuclear fleet and found that both were aligned, so we defined the representative age as the median of the fleet (44-years old). We then compared the reactor types, the locations, and the owners' business model and size in this filtered population to the overall fleet. Based on this approach, the representative multi-unit nuclear plant is a 44-year-old 2,400 MW (comprised of two 1,200 MW units) BWR merchant plant in Illinois with an owner that operates multiple plants.

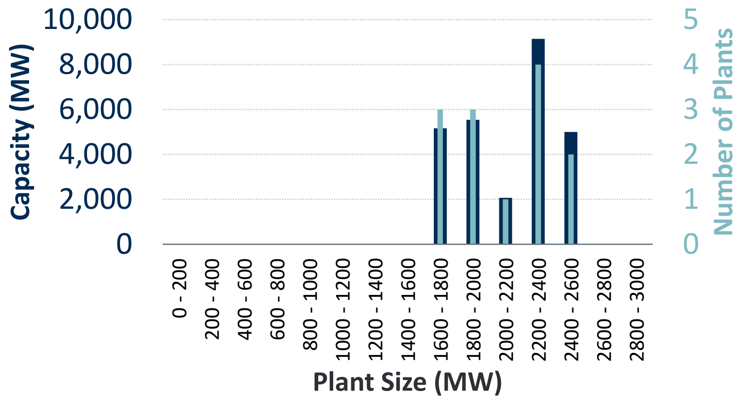
Given the limited number of nuclear plants and limited size variation, we did not alter the plant size for the representative low and high cost plants. For the representative low-cost plant, we chose a pressurized water reactor plant in Virginia, since PWRs have lower operating costs and Virginia has lower labor costs. For the representative high-cost plant, we assumed a plant similar to the representative plant but with the plant owner only operating a single plant, which would have higher costs due to reduced economies of scale.

FIGURE 1: MULTI-UNIT NUCLEAR FLEET CHARACTERIZATION

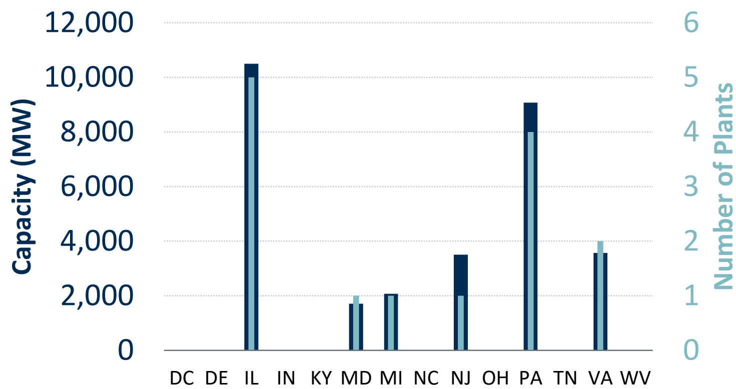
(A) UNIT AGE



(B) PLANT SIZE



(C) PLANT LOCATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Multi-Unit Nuclear Plant

Our cost estimates for nuclear plants rely the 2022 NEI "Nuclear Plants in Context" study, with adjustments to best reflect the representative plant and PJM's characterization of "gross" versus variable costs, as described below.[13] Corresponding to the NEI report's , we present nuclear cost components as ongoing capital expenditures and operating costs, then add property taxes, which NEI did not estimate.

Ongoing Capital Expenditures: NEI's capital cost category includes capital spares, regulatory, infrastructure, information technology, enhancements, and sustaining costs (including insurance costs). To estimate the capital cost contribution to gross costs (and variable costs) for PJM multi-unit nuclear plants, we started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of inflation at 7.66%.[14] We then adjusted this value downward by 16.73% to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator.[15] These adjustments yielded a total capital cost of $4.93/MWh in 2022 dollars. From this total, Capital Spares (1.2% of total capital costs) are excluded from the gross costs and counted as variable costs instead, consistent with PJM's tariff. Sustaining costs (37.2% of total capital costs) also are considered variable and excluded from the gross costs, since this category reflects investments in systems directly related to electric production that are necessary to maintain plant performance. In contrast to our prior approach in the 2020 Gross ACR Study, and in response to stakeholder feedback, we included the Enhancements component (36.3% of total capital costs) in the gross costs. These costs are part of continuing the life the plant, and they are incurred fairly consistently by the fleet over time; and they belong in gross costs as opposed to variable costs because they are not directly related to electricity production. The remaining 25.3% of capital costs include upgrades to the plant that are expected to occur on an annual basis and are not directly related to electricity production, so they too are included as a gross case. The resulting contribution of capital costs to multi-unit nuclear plants' gross costs is $3.04/MWh, and $1.89/MWh as part of variable costs (all in 2022 dollars).

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13 Nuclear Energy Institute, Nuclear Costs in Context, October 2022 ("NEI Report").

14 U.S. Bureau of Labor Statistics, Consumer Price Index US City Average. Value obtained from 2022 January to October average CPI divided by 2021 average CPI or 291.735/270.970 = 1.0766.

15 NEI tabulated values included sensitivities for these characteristics, each of which were considered as a percentage change from the national average. The averages of these percentages were applied to the national average CapEx to yield the 16.73% net adjustment.

Non-Fuel Operating Costs: NEI's operating cost category includes engineering, loss prevention, materials and services, fuel management, operations, support services, training, and work management. We started with the 2021 average operating costs for all nuclear plants in the U.S. of $18.07/MWh, plus a year of GDP inflation at 7.66%.[16] We then adjusted this value upward by 1.74% to account for the representative plant characteristics including its location, boiling water reactor, multiple units, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $19.79/MWh in 2022 dollars. The components of operating costs primarily reflect labor costs that are not directly attributable to the production of electricity and so are included in the gross costs. We interpret the Materials & Services costs (1.5% of total operating costs) to account for consumables required to operate the nuclear plants and thus include those costs as variable operating costs but exclude them from the gross costs. The remaining 98.5% of the total operating costs are included in the gross costs. We applied these percentages to the total operating costs for a multi-unit BWR plant to calculate the variable and fixed operating costs. The resulting contribution of operating costs to multi-unit nuclear plants' gross costs is $19.50/MWh, and $0.30/MWh as part of variable costs (all in 2022 dollars).

Property Taxes: Property tax costs were determined using S&L's project database and expertise. S&L's discussions with operators of nuclear facilities determined broad ranges of taxes are assessed on nuclear facilities depending on the location. We selected a median annual value of $1.01/MWh from this dataset and applied the same value to all nuclear units.

These capital, operating, and property tax cost components are combined to estimate the total gross costs shown in Table 2. The result for the representative multi-unit nuclear plant in PJM is $537/MW-day (in 2022 dollars). The estimated variable costs for the representative multi-unit nuclear plant are $2.19/MWh. For the representative low-cost plant, estimated gross costs are $476/MW-day and variable costs are $2.22/MWh. For the representative high-cost plant, estimated gross costs are $552/MW-day and variable costs are $2.20/MWh.

[16] See footnote 14.

TABLE 2: MULTI-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Multi-Unit Nuclear Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	2,400	2,400	2,400
Gross Costs	*$/MW-day*	$476	**$537**	$552
Capital Costs	*$/MW-day*	$72	**$69**	$69
Fixed Operating Costs	*$/MW-day*	$381	**$445**	$460
Property Taxes	*$/MW-day*	$23	**$23**	$23
Non-Fuel Variable Costs	*$/MWh*	$2.22	$2.19	$2.20
Operating Costs	*$/MWh*	$0.25	$0.30	$0.31
Major Maintenance	*$/MWh*	$1.96	$1.89	$1.90

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[17]

As described in Section I.A above, PJM's tariff specifies that major maintenance costs can be included in variable costs in cost-based energy offers, under a maintenance adder and includes activities such as repair, replacement, and major inspection. If PJM were to determine that major maintenance should instead be considered in gross costs and adapts its tariff accordingly, this would move the major maintenance adder ($1.89/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $43/MW-day, to $580/MW-day. For the representative low-cost plant, this would move $1.96/MWh out of variable costs and increase the gross costs by $45/MW-day to result in $521/MW-day. For the representative high-cost plant, this would move $1.90/MWh out of variable costs and increase the gross costs by $43/MW-day to result in $596/MW-day.

B. Single-Unit Nuclear Plants

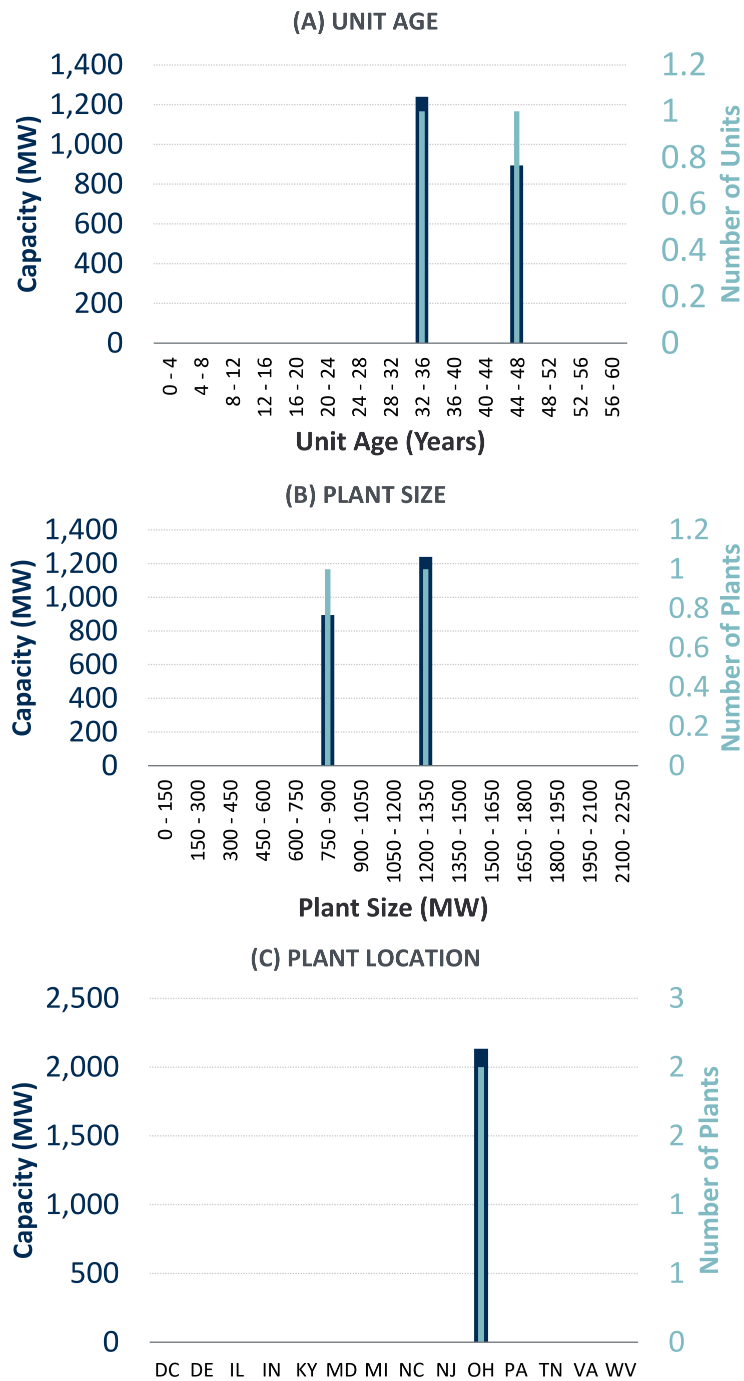
There are currently only two single-unit nuclear plants in the PJM market: the 894 MW Davis Besse plant and 1,240 MW Perry plant in Ohio.[18] Due to the small number of plants and the limited variation among them, we specified a single representative plant to be a 38-year-old 1,200 MW Boiling Water Reactor (BWR) unit in Ohio. With such a small population, we did not

[17] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

[18] See footnote 12, on the treatment of the Hope Creek plant in New Jersey.

designate a representative high or representative low-cost plant. Figure 2 below summarizes the age, size, and locations of these plants.

FIGURE 2: SINGLE-UNIT NUCLEAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Single-Unit Nuclear Plant

Costs for the single-unit nuclear plant are estimated from NEI data in the same way as for multi-unit plants. The capital and operating costs are higher per MWh, but the property taxes are assumed to be the same per MWh.

Ongoing Capital Expenditures: following the same approach outlined above for multi-unit nuclear plants, we estimated annual avoidable capital costs of $3.38/MWh as part of gross costs and $2.11/MWh as variable costs based. We started with the 2021 average capital costs for all U.S. nuclear plants of $5.50/MWh, plus a year of GDP inflation at 7.66%.[19] We then adjusted this value downward by 7.27% to account for the representative plant characteristics, including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. As with multi-unit nuclear plants, the gross costs exclude Capital Spares and Sustaining costs but include Enhancements and the remaining capital costs, using the same percentages as for multi-unit nuclear plants.

Non-Fuel Operating Costs: We estimated avoidable fixed operating costs of $21.52/MWh and variable operating costs of $0.33/MWh for a single-unit BWR nuclear plant, just as described above for multi-unit nuclear plants. We started with the 2021 average operating costs for all U.S. nuclear plants of $18.07/MWh, plus a year of GDP inflation at 7.66%.[20] We then adjusted this value upward by 12.32% to account for the representative plant characteristics including its location, boiling water reactor, single-unit, and merchant status within a multiple-plant portfolio of the operator. These adjustments yielded a total operating cost for our reference technology of $21.85/MWh in 2022 dollars. As with multi-unit nuclear plants, the gross costs includes 98.5% of that, with only Materials & Services costs attributed to variable costs.

Table 3 below shows the resulting gross costs for a representative single-unit nuclear plant in PJM to be $591/MW-day (in 2022 dollars). The estimated variable costs for a single-unit nuclear plant are $2.44/MWh (in 2022 dollars).

[19] See footnote 14.

[20] See footnote 14.

TABLE 3: SINGLE-UNIT NUCLEAR GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

	Units	Single-Unit Nuclear Plant
Capacity	*Nameplate MW*	1,200
Gross Costs	*$/MW-day*	**$591**
Capital Costs	*$/MW-day*	**$77**
Fixed Operating Costs	*$/MW-day*	**$491**
Property Taxes	*$/MW-day*	**$23**
Non-Fuel Variable Costs	*$/MWh*	$2.44
Operating Costs	*$/MWh*	$0.33
Major Maintenance	*$/MWh*	$2.11

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. The major maintenance costs per MWh depend on the capacity factor, which we assumed to be 95% corresponding to the average nuclear capacity factor in 2021.[21]

Similar to the multi-unit plant, if PJM determines major maintenance should be considered in gross costs instead of variable energy costs and adapts its tariff accordingly, this would move the major maintenance adder ($2.11/MWh) out of variable costs and increase the gross costs of the representative multi-unit nuclear plant by $48/MW-day, to $639/MW-day.

C. Coal Plants

The fleet of existing coal plants in PJM comprises a wide range of sizes, ages, and locations. There are over 120 existing coal units currently in the PJM market at approximately 60 different plant sites. Plant capacities range from less than 100 MW to nearly 3,000 MW with the average plant size of about 700 MW across all plants and 1,100 MW for plants that are at least 100 MW. Over half of the coal capacity is between 35–60 years old, with one plant dating back to 1942, and a few plants having come online in the last 10 years. West Virginia has the most installed capacity, followed by Pennsylvania and Ohio. The majority of coal plants have a dry lime or wet limestone flue-gas desulfurization (FGD) unit installed. Figure 3 below summarizes the age, size, locations, and pollution controls of these plants.

Coal plants of similar age tend to have similar plant size, configuration, and technology. The primary drivers of cost variability among plants are age (which typically dictates the capacity,

[21] Monitoring Analytics LLC, PJM's Independent Market Monitor, 2021 State of the Market Report for PJM Volume 2: Detailed Analysis, March 10, 2022.

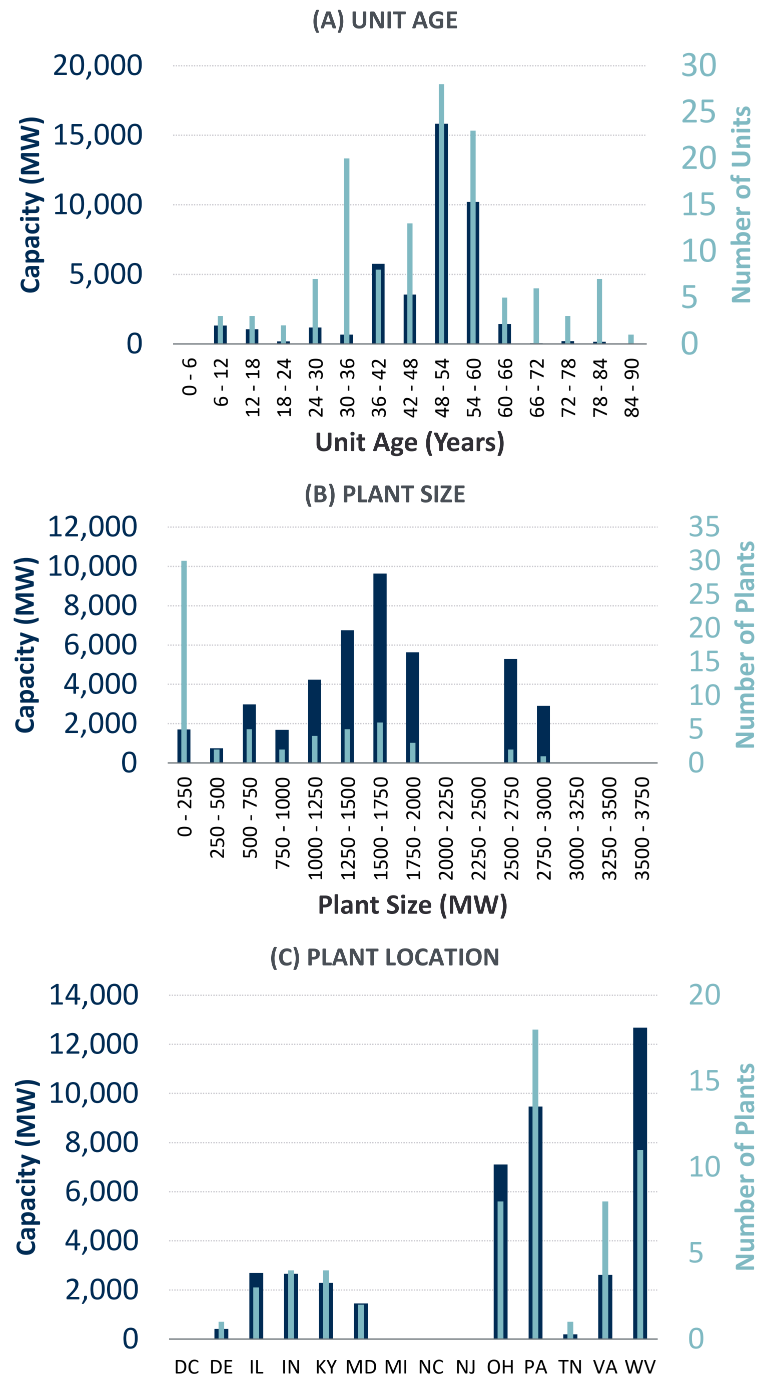
configuration, and technology), followed by the location and the types of post-combustion controls installed at the plant.

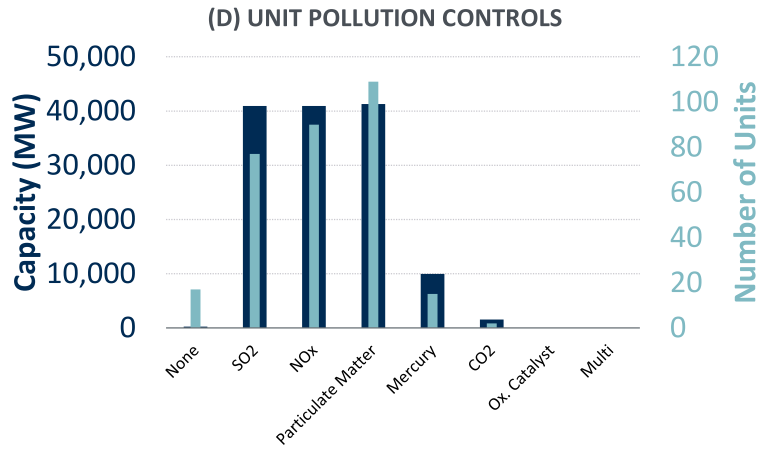
Representative Coal Plant Characteristics

Given that the age of a coal plant influences other cost drivers, we first determined the median plant age within the most frequent age bin of the coal fleet, which was between 48 to 54 years old as shown in Figure 3, Panel (A). We then filtered the coal fleet data by this age bin (48 to 54 years old) and compared the median age of the filtered population to the median age of the unfiltered total fleet. Both measurements were well aligned and were approximately 52 years old. Next, we determined the median capacity of the filtered population and reviewed the plant configurations of the filtered population. Then we reviewed the location of the filtered population and the installed pollution controls these plants had. Based on this approach, the representative coal plant is a 52-year-old 1,500 MW plant (with two 750-MW units) in Pennsylvania that burns Appalachian coal and has a wet limestone FGD unit.

For the representative low-cost plant and representative high-cost plant, we varied the age and capacity of the plant as the main cost differentiators. Because most coal plants in PJM have some type of sulfur dioxide control technology and the majority of them have wet FGD units, we did not change that assumption from the representative plant. To determine the representative high-cost plant, we filtered the fleet data for plants 30-years or younger and determined the median plant size and configuration of this filtered population, which was approximately a 100 MW plant consisting of one unit. We then reviewed the locations of these filtered plants. Based on this approach, the representative high-cost plant is a 30-year old 100-MW plant (one 100-MW unit) with FGD in West Virginia. For the representative low-cost plant, we only varied the capacity of the plant from the representative plant since larger plants would have lower per MW costs, and defined it as a 52-year-old 1,800 MW plant (with two 900-MW units) with FGD in Pennsylvania.

FIGURE 3: COAL FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Coal Plant

We estimated the total annual costs for operating the representative coal plant using data recently released by the EIA and FERC.[22] We reviewed the O&M costs, ongoing capital spending, and cost relationships across a broad range of plant configurations and developed our cost estimates by accounting for differences in unit sizes, number of units at the site, and ages in the reported costs relative to the representative plants. Our adjustments to the reported costs included estimation of staffing requirements, consumption of FGD reagent and other items, and disposal of ash and FGD sludge. The costs of staffing and other fixed expenses account for the economies of scale associated with larger unit sizes and multiple units at a site. We then validated the results against S&L's proprietary data for similar operating coal plants. Finally, where dollar values were referenced from a different year, we escalated the costs to 2022 using annual GDP inflation.[23]

Similar to the nuclear plants, we separated the costs that can be included in the gross costs from those included in the variable cost component of cost-based energy offers. Based on S&L's analysis of FERC Form 1 data and regression model for technically similar plants, a 52-year-old 1,500 MW coal plant would be expected to invest about $36 million in capital expenditures per year into the systems directly attributable to electricity production, which would be accounted

[22] EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018; Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

[23] See footnote 14.

for in the variable cost "maintenance adder" based on PJM's current market rules.[24] Assuming a 50% capacity factor, the maintenance adder contributes about $5.47/MWh to variable costs.[25] Meanwhile, the gross costs estimate includes fixed operating costs that are not directly attributable to electricity production, such as labor, administrative costs, preventative maintenance to auxiliary equipment (buildings, HVAC, water treatment), insurance, and support services.

Property tax rates vary by municipality or even by property where sometimes there are negotiated payment in lieu of taxes (PILOT) agreements, and plant values are not assessed in a uniform manner. To estimate property taxes for the representative coal plant, we surveyed actual property taxes payed by plants that were close to the representative plant size and applied the median value. We also leveraged this analysis to estimate insurance costs. Like property taxes, insurance costs depend on the value of the plant, although the costs are generally not publicly available. S&L has in the past shown that insurance costs tend to be roughly three times as high as property taxes paid by large thermal plants in S&L's project database, and we applied this multiplier. Both turned out to be very small.

Table 4 below shows that the estimated gross costs for the representative coal plant are $94/MW-day (in 2022 dollars), and the variable costs are estimated at $10.92/MWh. For the representative low-cost coal plant, estimated gross costs are $88/MW-day variable costs are $10.47/MWh. For the representative high-cost coal plant, estimated gross costs are $142/MW-day, and variable costs are $9.61/MWh.

24 PJM, Operating Agreement of PJM Interconnection, L.L.C., Schedule 2, Section 4.

25 The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

TABLE 4: COAL PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Coal Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,800	1,500	100
Gross Costs	*$/MW-day*	$88	**$94**	$142
Labor	*$/MW-day*	$38	**$41**	$60
Fixed Expenses	*$/MW-day*	$48	**$51**	$79
Property Taxes	*$/MW-day*	$0.5	**$0.5**	$0.5
Insurance	*$/MW-day*	$1.5	**$1.5**	$1.5
Non-Fuel Variable Costs	*$/MWh*	$10.47	$10.92	$9.61
Operating Costs	*$/MWh*	$5.00	$5.45	$5.62
Maintenance Adder	*$/MWh*	$5.47	$5.47	$3.99

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and insurance. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 50% capacity factor for the low-cost and median representative plants, and 62% for the high-cost representative plant.[26]

D. Natural Gas-Fired Combined-Cycle Plants

Nearly all natural gas-fired combined-cycle (CC) plants have been built over the past 25 years, with more than 22,000 MW installed in the past 5 years, and most of the rest built in the early 2000s. Plants built in the early 2000s are in the 500 MW to 1,000 MW range while more recent projects typically exceed 1,000 MW. Many of the gas CCs have been built in regions with access to low-cost gas via pipelines or within gas supply basins, predominantly in Pennsylvania, followed by Virginia, Ohio, and New Jersey. Most are equipped with Selective Catalytic Reduction (SCR) to reduce emissions of nitrogen oxides (NO_x). Figure 4 below summarizes the age, size, locations, and pollution controls of these plants.

The main drivers of cost variability among CCs are the capacity, age, turbine type, plant configuration, and whether or not a plant has firm gas transportation service. Location is a secondary driver, through its effects on the costs of labor, property taxes, and firm fuel.

[26] The capacity factors estimated are based on Figure 3-1 Capacity Factor vs. Age for All Coal Plants from the EIA's Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modelling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

Determination of Representative Natural Gas-Fired Combined-Cycle Plant Characteristics

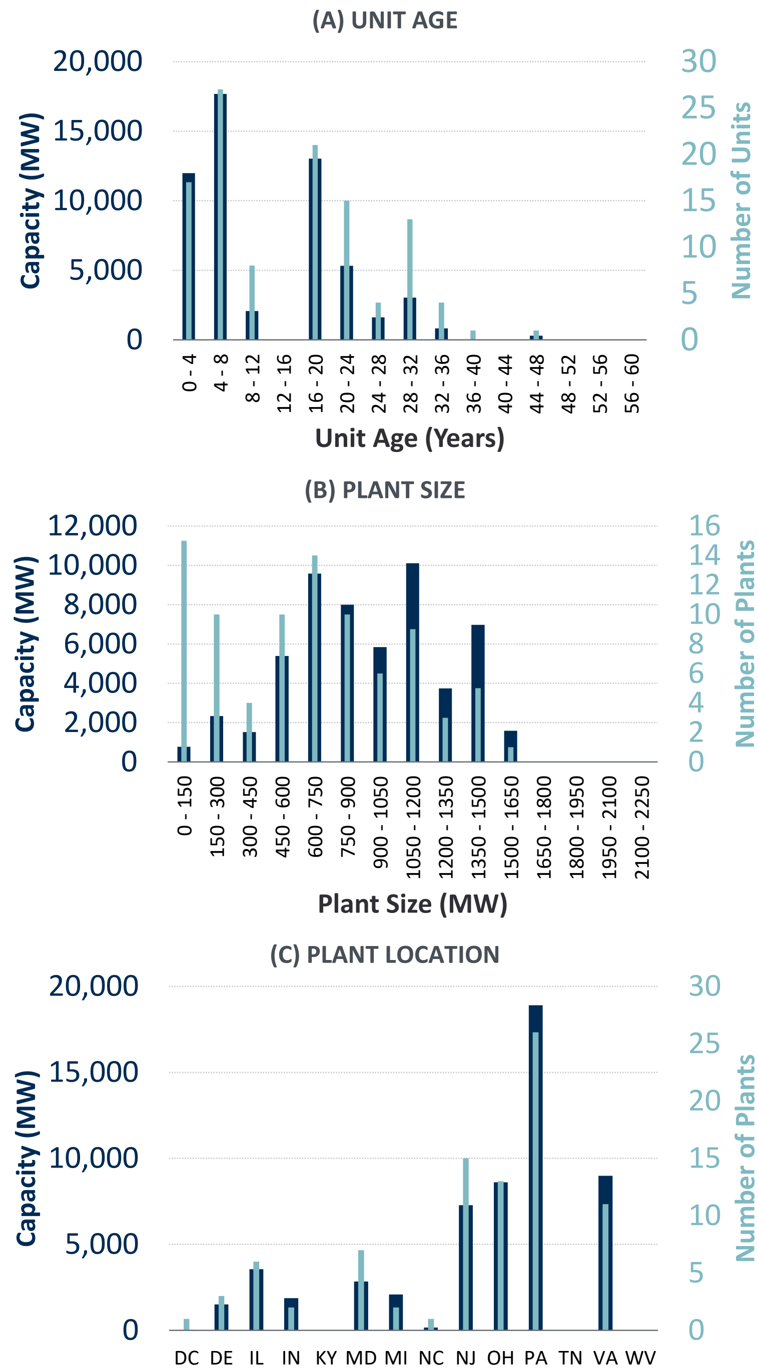
We relied on input from PJM indicating that the majority of existing CC plants have firm gas transportation contracts up to their economic maximum (EcoMax), and therefore the representative plant would be subject to this cost. Then we determined the median plant size of the CC fleet, which was 669 MW in the 600 MW to 750 MW bin as shown in Figure 4, Panel (B). We then filtered the CC fleet data for plants between 600 MW to 750 MW and compared the median age of the filtered population to the median age of the unfiltered total CC fleet and found that both were aligned, so we defined the representative age as the median of the fleet (11-years old). We then compared the plant configuration, location and the installed pollution controls in this filtered population to determine that most plants are in a 2×1 configuration, nearly all plants have SCR installed, and most are located in Pennsylvania. 11 years ago, F-class turbines were the predominant turbine technology, which had standardized sizes when employed in a 2×1 configuration. We adjusted the reference size to 750 MW to account for this standardization. Based on this approach, the representative gas CC plant is an 11-year-old 750 MW plant with two F-class gas turbines and one steam turbine (2×1) configuration in Pennsylvania that has SCR technology installed and has firm gas transportation service.

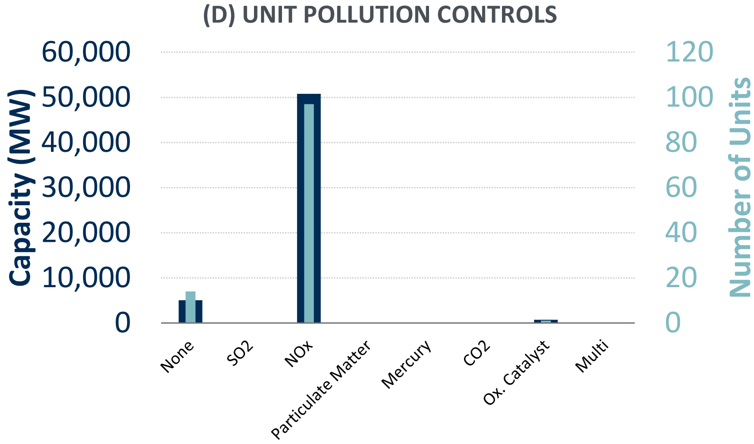
The representative high-cost and low-cost plants reflect the two modes of the bi-modal distribution of ages of CC plants in PJM. The older plants are smaller and have higher costs per MW-day, where newer plants are larger and have lower costs per MW-day with their economies of scale. Since nearly all CC plants in PJM have SCR installed for NO_x pollution control, we did not vary this assumption for the representative high or low-cost plants. Because the majority of the CC feet has firm gas up to EcoMax we also assume that the representative low-cost and representative high-cost plants have firm gas transport service as well.

For the representative high-cost plant, we first identified a plant size that was representative of the smaller plants in the fleet. We split the CC fleet into plants smaller than 750 MW and found the median of this sub-population, which were plants between 300 MW to 450 MW. We then filtered the CC sub-population for plants between 300 MW to 450 MW and chose a 400 MW median to represent the smaller/older CCs. New Jersey has the second most CCs in PJM so we chose this location for the representative older/smaller plant. The median CC plant age in New Jersey is approximately 30-years old. We assessed the plant configuration and turbine type of plants in this size range to be an F-class single unit. Based on this approach, the representative high-cost CC plant is a 30-year-old, 400 MW plant, with one F-class turbine in a 1×1 configuration in New Jersey.

For the representative low-cost plant, we identified plants in the 1,050–1,200 MW range, which represents a large proportion of the capacity and a high number of plants as shown in Figure 4, Panel (B). We filtered the CC fleet data by this size bin to obtain the representative low-cost age at a median of 5 years old. We used the CC fleet data filtered by this size to determine the plant configuration, turbine type, and location of the remaining plants. CC plants around this size and age tended to be larger with H-class turbines in a 2×1 configuration. Based on this approach, the representative low-cost CC plant is a 5-year-old 1,100 MW plant with two 550 MW H-class turbines in a 2×1 configuration in Pennsylvania.

FIGURE 4: NATURAL GAS-FIRED COMBINED CYCLE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for the Representative Natural Gas-Fired Combined-Cycle Plants

To estimate the costs of the representative plants, we relied on the same methodology used to develop cost estimates for gas CCs in the PJM 2022 CONE Study.[27] Similar to how costs are specified in the 2022 CONE Study, we included the hours-based major maintenance costs specified in Long-Term Service Agreements (LTSAs) under variable O&M costs alongside operating costs associated with chemicals and consumables.

We used the cost information from the 2022 CONE Study to estimate components of the fixed O&M, variable O&M, and major maintenance for the representative low-cost plant (H-class 2×1). Other public sources and S&L's project database containing a broad range of CC configurations were used for estimating the cost components for the 750 MW and 400 MW F-class representative plants.

We adjusted the cost data from public sources to account for differences in turbine sizes, configurations, locations, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.[28] These adjustments accounted for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site. The costs of major maintenance and consumables were derived using a 62% capacity factor, representative of CCs in PJM. Property taxes and insurance were estimated using the values

[27] Newell, et al., PJM CONE 2026/2027 Report, April 21, 2022 ("2022 CONE Study").

[28] Adjustments come from S&L project database and public sources including FERC Form 1 and EIA, Generating Unit Annual Capital and Life Extension Costs Analysis Final Report on Modeling Aging-Related Capital and O&M Costs, prepared by Sargent & Lundy, May 2018.

from the 2022 CONE study[29] with downward adjustments made for the older, less valuable plant.

Firm gas transportation costs were estimated at updated average tariff rate of $8.06/Dth per month incorporating reservation and usage charges for major pipelines servicing Pennsylvania under the FT-1 rate schedules.[30] We calculated the average heat rate for all natural gas-fired combined-cycle plants in the PJM fleet to be 7,212 Btu/kWh.[31] We then multiplied the nameplate plant capacity for the representative plants with the heat rate to estimate the average annual gas requirement. We then calculated the annual firm gas cost of $46/MW-day using the average tariff rate of $8.06/Dth per month applied to the annual gas requirement.

Table 5 below shows that the estimated gross costs for the representative plant are $113/MW-day and variable costs are $2.71/MWh (in 2022 dollars). The estimated gross costs for the representative low-cost plant are $94/MW-day and variable costs are $2.36/MWh. Estimated gross costs are higher for the smaller 400 MW representative high-cost plant at $160/MW-day due to the reduced economies of scale. The variable costs for the representative high-cost plant are $2.60/MWh.

Note that the $113/MW-Day gross costs of the representative existing CC plant are similar to the Fixed O&M costs for new CCs from the 2022 CONE Study as part of the Quadrennial Review.[32] Accounting for updates incorporated into the final submitted CONE values[33] and deflating those estimates to 2022 dollars, the Fixed Operation & Maintenance cost for the new CCs in the WMACC CONE Areas (most closely corresponding to the "PA" location of the representative existing CC) plant is $83/MW-day. This is $11/MW-day less than the $94/MW-day we are estimating for the gross costs of the comparably sized "Low-Cost" existing plant. The difference is primarily attributable to updated tariffed rates used to estimate the costs of firm fuel, partially offset by lower property taxes and insurance, and other adjustments.

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29 2022 CONE Study.

30 The tariff rate used in calculation of firm gas costs was the average of TETCO M3 rate and Transco Zone 6 rate. See Texas Eastern Transmission FERC Gas Tariff, M3-M3 effective August 1, 2022, and Transcontinential Gas Pipeline Company FERC Gas Tariff, Delivery Zone 6 and Receipt Zone 6 effective November 1, 2022.

31 Based on average full load heat rates with data from ABB, Energy Velocity Suite. Many combined-cycle plants employ duct firing to produce higher-pressure steam to increase plant capacity when operating in high ambient temperatures. However, the use of duct firing in CCs causes the efficiency to drop significantly and plants are not designed to be operated constantly with duct firing throughout a year; therefore, we calculate the annual gas requirement using the average full load heat rate without duct-firing.

32 PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

33 *Ibid*, Attachment D.

TABLE 5: COMBINED-CYCLE PLANTS' GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Natural Gas Combined Cycle Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	1,100	750	400
Gross Costs	*$/MW-day*	$94	**$113**	$160
Labor	*$/MW-day*	$17	**$21**	$32
Fixed Expenses	*$/MW-day*	$52	**$72**	$120
Property Taxes	*$/MW-day*	$6	**$5**	$2
Insurance	*$/MW-day*	$19	**$15**	$6
Non-Fuel Variable Costs	*$/MWh*	$2.36	$2.71	$2.60
Operating Costs	*$/MWh*	$0.75	$0.52	$0.94
Maintenance Adder	*$/MWh*	$1.61	$2.19	$1.66

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general, and firm gas transportation service. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders assume a 62% capacity factor.

E. Simple-Cycle Combustion Turbines

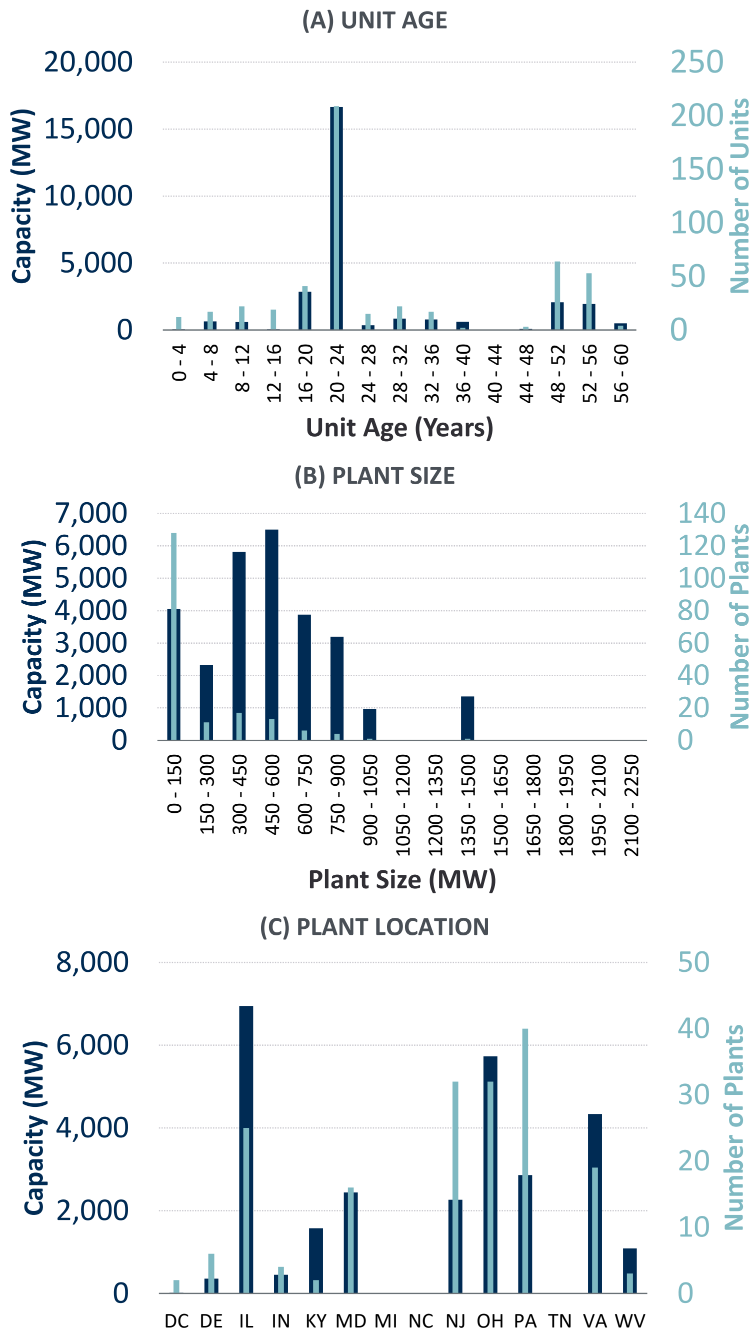
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. There are many CT plants in the PJM fleet under 150 MW, but these plants cumulatively do not constitute a large amount of capacity compared to the larger plants in the 300–600 MW range. Most were built 20–24 years ago and the states with the most CTs include Ohio, Illinois, Pennsylvania, New Jersey, and Virginia. Unlike CCs, most CTs are not built with an SCR unit. Figure 5 below summarizes the age, size, locations, and pollution controls of these plants. The primary cost drivers for CTs are capacity, age, turbine type and configuration, and location.

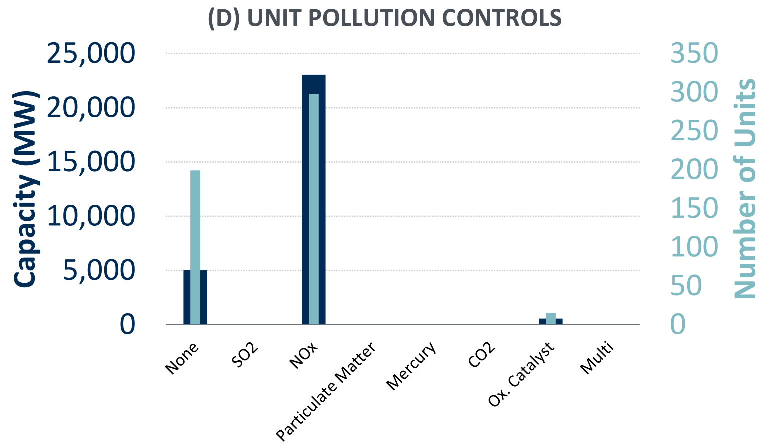
Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics

The median size of the fleet was 320 MW between the 300 MW to 450 MW size bin, as shown in Figure 5, Panel (B). We compared the median age of the CT fleet to the median age of the filtered population and found that both were approximately 20 years old. 20 years ago, F-class turbines were the predominant turbine technology. We then reviewed the location and configuration of the filtered population. Based on this approach, the representative CT plant is a 20-year-old 320 MW plant with two F-class turbines (2×160 MW) located in Illinois. Unlike CC plants, the majority of existing CT plants do not have firm gas transportation contracts up to EcoMax, according to PJM, so transportation costs were not included.

Because nearly all CT plants were built around the same time, we did not vary the age for the representative low-cost and representative high-cost plants and instead chose the low and high cost representative plant based on other factors. As shown in Figure 5 Panel (B), there are many plants that are less than 150 MW. To determine the representative low-cost plant, we filtered the 20-year-old CT fleet for plants smaller than 150 MW and determined the median capacity of this filtered population, which was 100 MW. Plants of this size were most frequently in Pennsylvania and typically use two LM600 aeroderivative turbines. Based on this approach, the representative high-cost CT is a 100 MW plant with two LM6000 aeroderivative turbines (2×50 MW) in Pennsylvania. To determine the representative low-cost plant, we filtered 20-year-old plants for sizes above 450 MW and found the median size of this filtered population, which was approximately 640 MW. These plants were most frequently in Illinois. Many plants of this size use several E-class turbines. Therefore, the representative low-cost CT is a 640 MW plant with eight E-class turbines (8×80 MW) in Illinois.

FIGURE 5: SIMPLE CYCLE COMBUSTION TURBINE FLEET CHARACTERIZATION





Notes and Sources: ABB, Energy Velocity Suite.

Cost Estimates for Representative Simple-Cycle Combustion Turbine Plants

To estimate costs, we reviewed cost estimates reported by the 2022 CONE Study, cost estimates from the EIA, and S&L's project database.[34] We then developed the cost estimates for existing CTs similar to the representative plants by adjusting the publicly reported costs for differences in turbine sizes, configurations, locations, and ages. We validated the results of our cost estimates against proprietary data in S&L's project database for similar plants in operation. The adjustments account for staffing requirements and the economies of scale associated with larger turbine sizes and multiple turbines at a site.

The CT technologies included in the ACR study are significantly different from the selected single GE model 7HA.02 reference technology from the 2022 PJM CONE study, thus estimation of their property taxes and insurance was performed using the most representative references available in S&L's project database. Both property taxes and insurance were estimated based on a regression analysis of similar technologies with adjustments made for the size, type, and age of the CTs in this study. The high-cost plant is an aeroderivative, which is a fundamentally different technology, so costs were estimated from a different data set of similar plants.

The E-class and F-class turbines that operate as peaking units would be expected to trigger major maintenance events based on the number of starts. For this reason, we estimated the variable cost maintenance adder assuming a 10% capacity factor and 12 hours of operation per start. The LM6000 turbines however, would likely trigger major maintenance based on hours of operation therefore their maintenance adder is independent of the number of starts per year.

[34] 2022 CONE Study; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

Table 6 below shows the resulting gross and variable costs for the simple cycle CT plants. The estimated gross costs of the representative CT are $52/MW-day and the variable costs are $4.29/MWh (in 2022 dollars). For the representative low-cost plant, the estimated gross costs are $43/MW-day and variable costs are $4.29/MWh. For the representative high-cost plant, estimated gross costs are $69/MW-day and variable costs are $5.39/MWh.

We also validated these costs against the Fixed O&M costs accepted in PJM's tariff as part of the 2022 CONE Study.[35] Accounting for subsequent updates in later affidavits, and deflating those estimates to 2022 dollars, the published Fixed Operation & Maintenance cost for the same area as the representative plant is $93/MW-day. This value included the cost of firm gas contracts, which amounted to approximately $49/MW-day in 2022 dollars. Excluding the firm gas cost, the 2022 CONE study Fixed Operation & Maintenance cost for new CTs becomes $44/MW-day, which is close to our representative plant gross costs of $52/MW-day. This difference is primarily attributable to the staffing assumptions made for the representative 2×160 MW existing plant compared to the 1×353 MW new plant in the CONE study.

TABLE 6: SIMPLE-CYCLE COMBUSTION TURBINE PLANTS GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Simple Cycle Combustion Turbine Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	640	320	100
Gross Costs	*$/MW-day*	$43	**$52**	$69
Labor	*$/MW-day*	$6	**$10**	$23
Fixed Expenses	*$/MW-day*	$8	**$12**	$28
Property Taxes	*$/MW-day*	$16	**$16**	$3
Insurance	*$/MW-day*	$13	**$13**	$16
Non-Fuel Variable Costs	*$/MWh*	$4.29	$4.29	$5.39
Operating Costs	*$/MWh*	$0.42	$0.42	$0.97
Maintenance Adder	*$/MWh*	$3.88	$3.88	$4.43

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses in the gross costs includes preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, and administrative and general. The maintenance adder assumes a 10% capacity factor with 12 hours per start. Actual major maintenance costs will vary with the number of starts, not strictly with MWh as expressed in this table, and will depend on actual duty cycles and maintenance agreement terms.

[35] PJM Interconnection, L.L.C., Docket No. ER22-2984-000 Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, pdf page 364.

F. Oil- and Gas-Fired Steam Turbines

Steam turbine plants fueled by oil and gas (ST O&G) have a wide range of sizes. The majority of ST O&G plants are less than 25 MW but collectively do not contribute much capacity to the fleet. The average size is about 250 MW, which is skewed by a few very large plants on the order of 700 to 1,700 MW. Most of the larger plants and thus most of the capacity is located in Pennsylvania. Smaller plants are in Ohio, Maryland, and New Jersey. Ages of ST O&G plants range from 2–85 years old, with most capacity being 40–50 years old. Figure 6 below summarizes the age, size, locations, and pollution controls of these plants. The primary drivers of cost for ST O&G plants are age, capacity, location, and plant configuration.

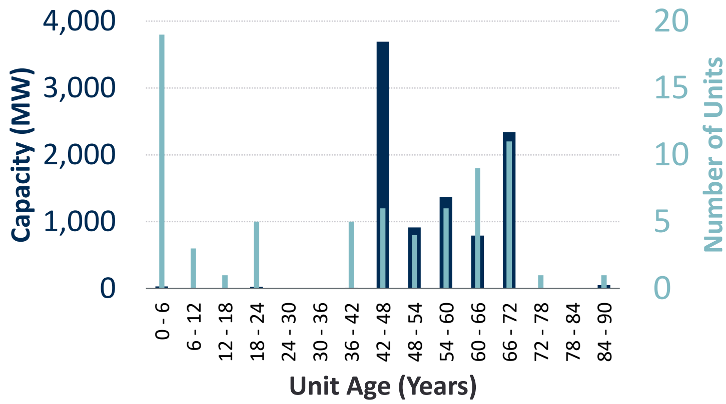
Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics

The median MW in PJM's ST O&G fleet is in a 900 MW plant. We filtered the ST O&G fleet by this approximate size and compared the age of the filtered fleet with the age of the whole fleet. The age bucket contributing the most capacity to the ST O&G fleet are plants aged 42–48 years old, shown in Figure 6, Panel (A). We defined the representative age to be in this bucket (47-years old), which aligned with the ages of the filtered fleet. After further filtering for age, we ensured that the location of our representative plant reflected the location distribution of the whole fleet. The majority of existing ST O&G plants do not have firm gas transportation contracts up to EcoMax, according to PJM. Based on this approach, the representative ST O&G plant is a 47-year-old, 900 MW plant in Pennsylvania, without firm gas.

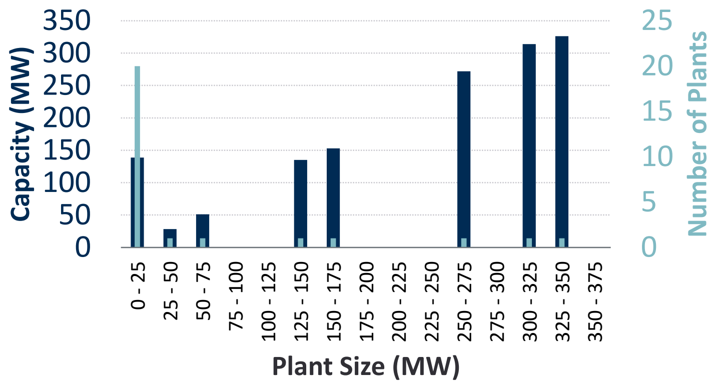
Since the majority of both ST O&G plants and capacity are in Pennsylvania, we did not vary the location for the representative low- and high-cost plants. To reflect the many small plants in the fleet, we filtered for plants under 900 MW. For plants in Pennsylvania under this size, we chose an approximate median of 350 MW to be the representative high-cost plant size. We then filtered the fleet for plants of approximately 350 MW and found that the median age of these smaller plants was 65 years old. Based on this approach, the representative high-cost ST O&G plant is a 65-year-old, 350 MW plant in Pennsylvania. To identify a representative low-cost plant, we began by selecting a larger plant to reflect economies of scale and filtered for plants above 900 MW. We determined a representative high-cost plant size of 1,300 MW. These larger plants have a median age of 47-years old. Based on this approach, the representative low-cost ST O&G plant is a 47-year old, 1,300 MW plant in Pennsylvania.

FIGURE 6: OIL AND GAS-FIRED STEAM TURBINE FLEET CHARACTERIZATION

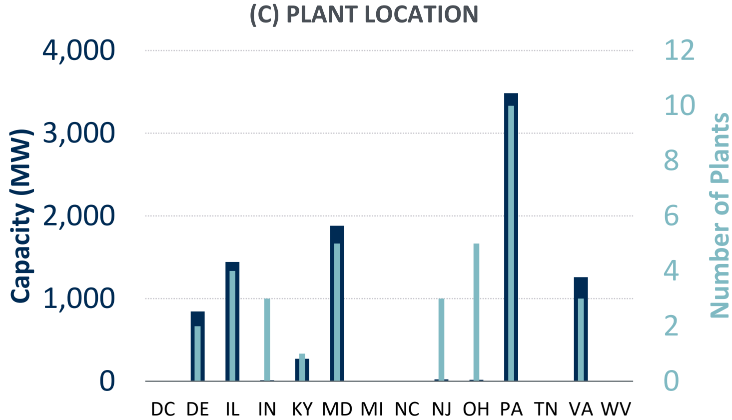
(A) UNIT AGE

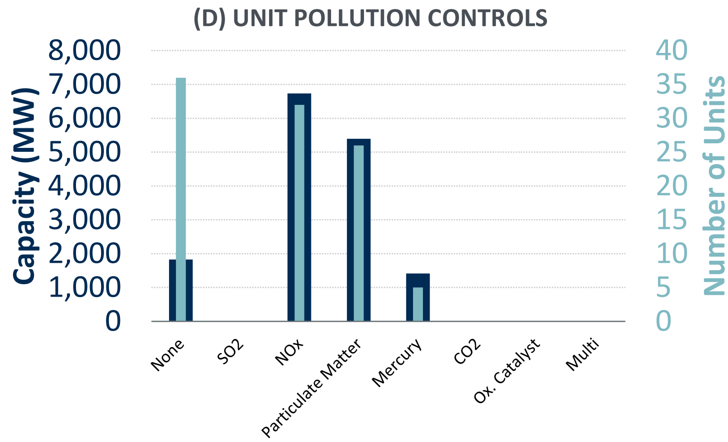


(B) PLANT SIZE



(C) PLANT LOCATION





Notes and Sources: ABB, Energy Velocity Suite. In Panel (B), the distribution is truncated at 375 MW to maintain legibility, but ST O&G plants range up to 1,700 MW with nine plants above 375 MW.

Cost Estimates for Representative Oil and Gas-Fired Steam Turbine Plant

To estimate the costs of the representative plants, we relied primarily on public cost information from the FERC Form 1, and S&L's project database.[36] We then developed the cost estimates for the representative plants accounting for differences in plant sizes, plant location, and ages based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation. For property taxes and insurance, we used the same survey approach as for coal described in Section III.C above, but in this case based on actual ST O&G plants in PJM. We again estimated insurance costs at three times as high as property taxes. Both turned out to be very small.

Table 7 below shows that the estimated total gross costs for the representative plant are $64/MW-day (in 2022 dollars) and variable costs are $5.81/MWh. For the representative low-cost ST O&G plant, estimated gross costs are $53/MW-day and variable costs are $5.51/MWh. For the smaller 350 MW representative high-cost plant, gross costs are significantly higher, at $102/MW-day, due to the reduced economies of scale; variable costs are $16.26/MWh.

[36] Federal Energy Regulatory Commission, FERC Form 1, Plant Cost Data, 2010 through 2019.

TABLE 7: STEAM OIL & GAS PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Oil and Gas-Fired Steam Turbine Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	1,300	900	350
Gross Costs	*$/MW-day*	$53	**$64**	$102
Labor	*$/MW-day*	$21	**$26**	$43
Fixed Expenses	*$/MW-day*	$26	**$32**	$53
Property Taxes	*$/MW-day*	$1.6	**$1.6**	$1.6
Insurance	*$/MW-day*	$4.8	**$4.8**	$4.8
Non-Fuel Variable Costs	*$/MWh*	$5.51	$5.81	$16.26
Operating Costs	*$/MWh*	$1.19	$1.19	$1.19
Maintenance Adder	*$/MWh*	$4.32	$4.62	$15.07

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include preventive maintenance on auxiliary equipment (buildings, HVAC, water treatment, freeze protection, etc.), information technology, miscellaneous supplies, support services, administrative and general expenses. The estimated maintenance adder costs per MWh are variable based on the capacity factor. The maintenance adders for the low-cost and representative plant assume a 20% capacity factor and the maintenance adder for the high-cost plant assumes a 10% capacity factor.

G. Onshore Wind Plants

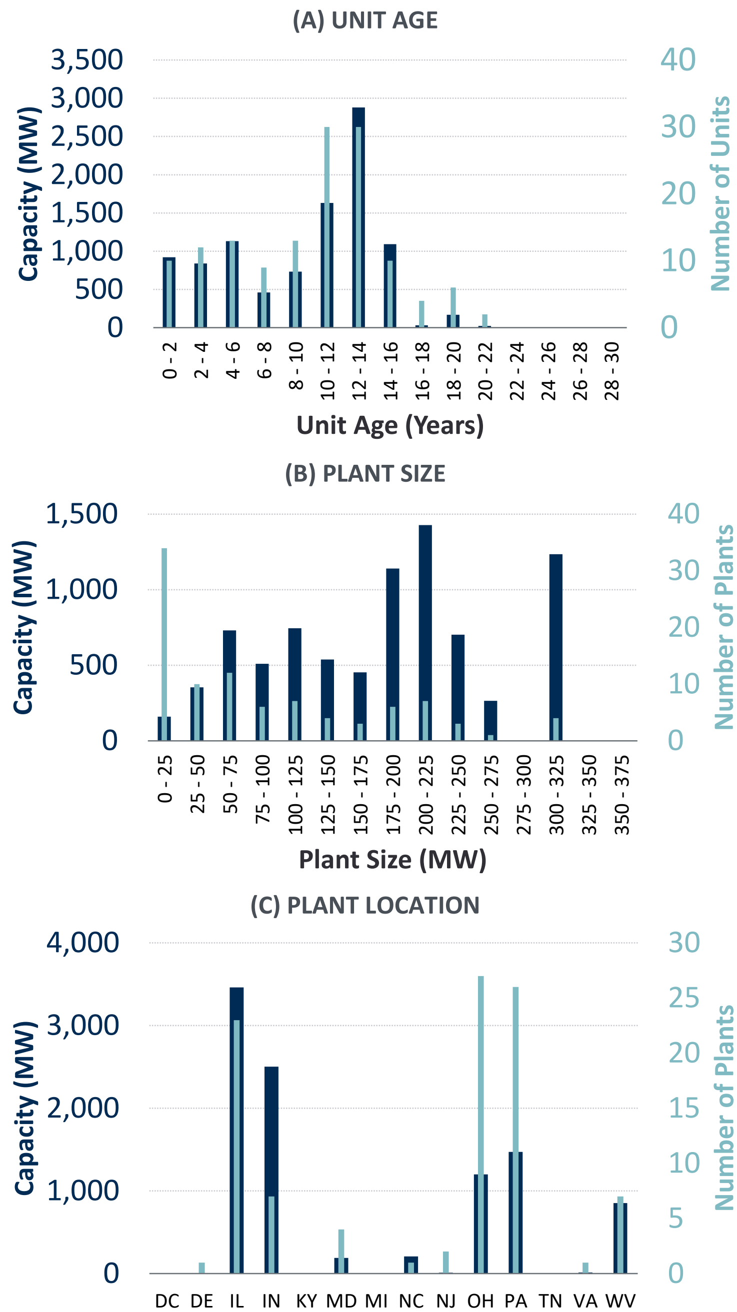
Over the past 15 years, nearly 10,000 MW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by the numerous small plants (less than 25 MW); however, 17 are at least 200 MW as shown in Figure 7 Panel (B) below. Plants larger than 100 MW make up of over 80% of the total capacity in PJM, and most are located in Illinois and Indiana, while smaller plants are located in Pennsylvania and Ohio. Ages of wind plants range from less than a year old to 20 years old. Figure 7 below summarizes the age, size, and locations of these plants. The primary cost drivers for wind plants tend to be the size and location, then the age and density of individual wind turbines at a plant site.

Determination of Representative Onshore Wind Plant Characteristics

To determine the representative onshore wind plant, we filtered the wind fleet for plants greater than 100 MW (since these plants contribute to more than 80% of the total capacity) and determined the median plant size of this filtered population, which was approximately 200 MW. We then found the median age of this filtered fleet, which was approximately 12 years old and reviewed the most frequent location, which was Illinois. Based on this approach, the representative onshore wind plant is a 12-year-old, 200 MW plant in Illinois.

To account for the size and age variation of the fleet, we varied these characteristics when determining the representative low-cost and representative high-cost plant. We filtered the wind fleet for plants less than 100 MW and determined a median size of 30 MW for the representative high-cost plant. We then found the median age of this filtered fleet, which was similar to the age for representative plants, so we maintained a 12-year-old plant. The most frequent location of these smaller plants was Pennsylvania. Based on this approach, the representative high-cost plant is a 12-year-old 30 MW plant in Pennsylvania. We increased the capacity for the representative low-cost plant to be a 300 MW plant, the median size for plants above 200 MW. By filtering for larger plants, we determined that the median age was slightly younger than the representative high-cost plant (10 years old) and the most frequent location was in Illinois. Based on this approach, the representative low-cost plant is a 10-year-old 300 MW plant in Illinois.

FIGURE 7: ONSHORE WIND PLANTS FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 375 MW to maintain legibility, but wind plants range up to about 900 MW with two plants larger than 375 MW.

Cost Estimates for Representative Onshore Wind Plants

We estimated fixed and variable O&M and capital costs for the representative wind plants by first reviewing recent public sources and S&L's project database.[37] We then developed the cost estimates for the representative plants accounting for differences in MW capacity, plant location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative wind plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the total fixed operating expenses based on S&L's project database for similar sized wind plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 8 below shows resulting gross costs for the representative plant of $147/MW-day (in 2022 dollars). We assumed that all of the costs necessary to operate a wind plant (and a solar PV plant) are fixed and belong in the gross costs, with no variable costs. The representative low-cost plant's estimated gross costs are $140/MW-day, and the representative high-cost plant's gross costs are $204/MW-day.

[37] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 8: ONSHORE WIND PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Onshore Wind Plant		
	Units	**Representative Low-Cost Plant**	**Representative Plant**	**Representative High-Cost Plant**
Capacity	*Nameplate MW*	300	200	30
Gross Costs	*$/MW-day*	$140	**$147**	$204
Labor	*$/MW-day*	$26	**$27**	$50
Fixed Expenses	*$/MW-day*	$95	**$99**	$126
Property Taxes	*$/MW-day*	$12	**$13**	$17
Insurance	*$/MW-day*	$8	**$8**	$11
Non-Fuel Variable Costs	*$/MWh*	$0.00	$0.00	$0.00
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled wind turbine and balance-of-plant maintenance, parts and consumables, operations monitoring, land lease, general and administrative costs.

H. Large Scale Solar Photovoltaic Plants

Large-scale solar photovoltaic (PV) plants tend to be fairly small in PJM, with most plants under 10 MW and a few in the 50–100 MW range. All of the solar PV plants have been built in the past 15 years, with the most capacity added in Virginia, New Jersey, and North Carolina. Figure 8 below summarizes the age, size, and locations of these plants.

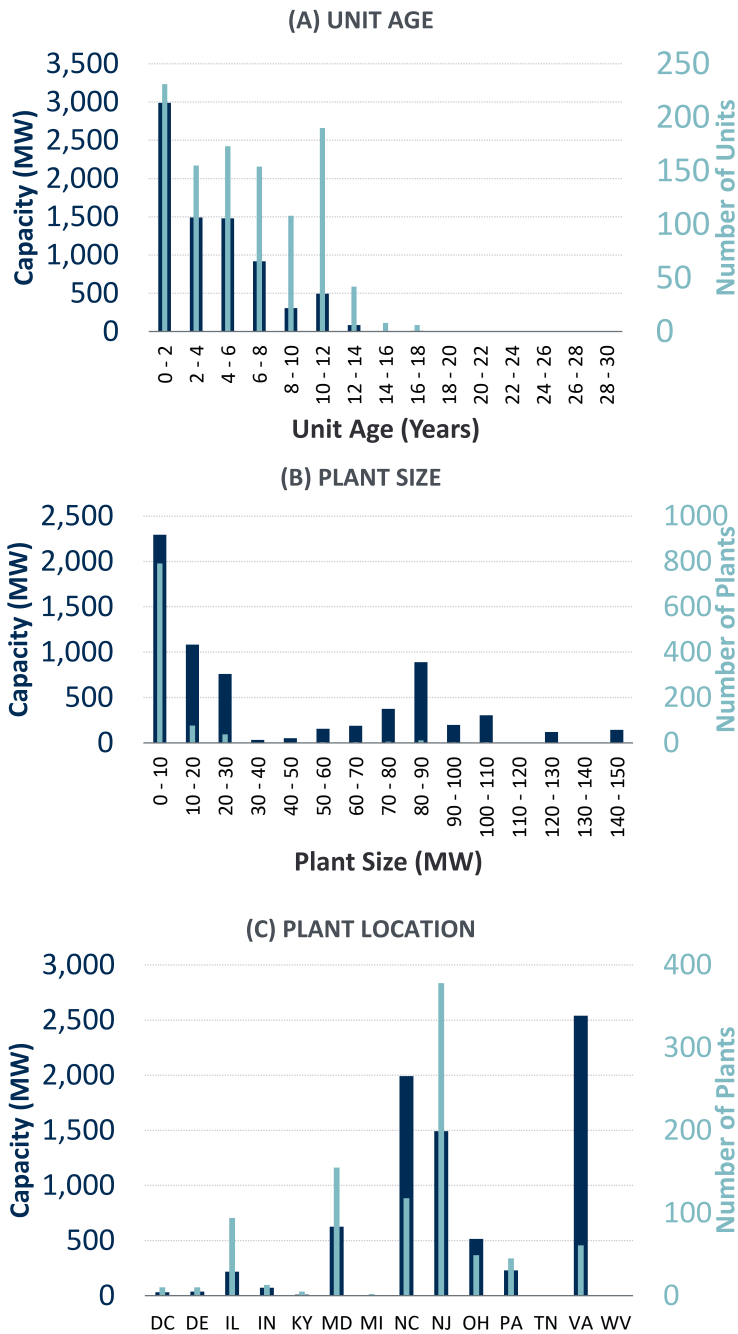
The age of a solar plant influences the plant capacity since more recent plants have tended to be built larger than in the past. Location also impacts the costs of solar PV plants due to differences in labor costs and property taxes.

Determination of Representative Large Scale Solar Photovoltaic Plant Characteristics

Because the age of a solar plant influences the plant size, to choose a representative solar plant we first determined the median age of the fleet, which was 5 years old. We filtered the solar fleet data by this age and compared the median plant size of this population to the median plant size of the fleet, which was approximately 10 MW. Then we reviewed the location of the fleet and the population with age and size filters. Based on this approach, the representative plant is a 10 MW single-axis tracking solar PV plant in New Jersey built 5 years ago.

For the representative high and low-cost plants, we varied size and age as the cost differentiators. The solar fleet is largely small plants 10 MW and under. For higher-cost plants under 10 MW, the median capacity is 2 MW. We filtered the solar fleet for plants of this size and determined these plants were slightly older than our representative plant (7 years old). We then analyzed the location of these smaller plants and found that they aligned with the most common location of the overall fleet, so we maintained the location as New Jersey. The representative low-cost plant would be much larger, but we avoided plants less than 5 years old because of the maintenance warranties that apply to younger plants and are not representative of the entire fleet. We filtered the entire fleet data by plants between 80–90 MW. The larger plants were most frequently located in North Carolina. Based on this approach, the representative low-cost plant is an 80 MW 5-year-old plant in North Carolina.

FIGURE 8: LARGE SCALE SOLAR FLEET CHARACTERIZATION



Notes and Sources: ABB, Energy Velocity Suite. In panel (B), the distribution is truncated at 150 MW to maintain legibility, but Solar PV plants range up to 500 MW with five plants larger than 150 MW.

Cost Estimates for Representative Large Scale Solar Photovoltaic Plants

We estimated fixed and variable O&M and capital costs for the representative solar PV plants by reviewing recent public sources and S&L's project database.[38] We then developed the cost estimates for the representative solar PV plants accounting for differences in the solar panel type, tracking type, plant size, location, and ages relative to the representative plants based on regression analyses of data from S&L's project database and validated the results against proprietary data for similar plants in operation.

The representative solar plants were assumed to pay property taxes or have a negotiated payment in lieu of taxes (PILOT) agreement with the local jurisdiction. S&L found these costs to be accurately represented as a fixed fraction of the overnight capital cost of the installation based on S&L's project database for similar sized solar plants. Insurance includes liability insurance, property insurance, and equipment insurance, and the cost of insurance will depend on the location's specific risks such as potential for damage from hail, or other natural disasters. Values in the table below represent S&L's estimates based on systems in locations without any atypical regional risks, and have not been adjusted for any other regional cost sensitivities.

Table 9 below shows that we estimated gross costs for the representative solar PV plant to be $70/MW-day (in 2022 dollars). Similar to onshore wind plants, we assumed that all of the costs necessary to operate a solar PV plant are fixed costs that are not directly attributable to the production of electricity, and thus did not include any variable costs for the solar PV plants. We estimated the representative low-cost gross costs to be $65/MW-day and the representative high-cost plant to be $74/MW-day.

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[38] National Renewable Energy Laboratory (NREL), 2022 Annual Technology Baseline, 2022; U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

TABLE 9: SOLAR PV PLANT GROSS AND NON-FUEL VARIABLE COSTS (2022 DOLLARS)

		Large Scale Solar Photovoltaic Plant		
	Units	Representative Low-Cost Plant	Representative Plant	Representative High-Cost Plant
Capacity	*Nameplate MW*	80	10	2
Gross Costs	*$/MW-day*	$65	**$70**	$74
Labor	*$/MW-day*	$20	**$22**	$25
Fixed Expenses	*$/MW-day*	$30	**$33**	$36
Property Taxes	*$/MW-day*	$5	**$4**	$4
Insurance	*$/MW-day*	$10	**$10**	$10
Non-Fuel Variable Costs	*$/MWh*	$0.00	$0.00	$0.00
Operating Costs	*$/MWh*	$0.00	$0.00	$0.00
Maintenance Adder	*$/MWh*	$0.00	$0.00	$0.00

Notes and Sources: gross costs are expressed in 2022 dollars per nameplate MW. Fixed Expenses include scheduled and unscheduled PV and BOP equipment maintenance, vegetation management, module cleaning, major maintenance reserve funds, land lease, general and administrative costs.

Interconnection Process Reform Task Force Update

Jason Connell
Infrastructure Planning

Planning Committee
May 11, 2021

Task Force Update

- First meeting was April 23
  - Education – existing interconnection process summary
  - Review the work plan
    - Targeting completion by year end
  - Interest identification
    - Study Process
    - Cost Concerns
    - Interim Operation/Agreements
    - Application requirements

Backlog Update

- PJM is reprioritizing its interconnection queue work
  - AG1 System Impact Studies will remain on schedule for August
  - AG2 Feasibility Studies will be postponed until at least January 2022
  - Staff will shift focus to backlogged studies
  - Staff augmentation over the next six months
- Next IPRTF meeting is June 1, 2021

PJM Interconnection Queue Status Update

Onyinye Caven
Interconnection Projects
Planning Committee
May 11, 2021

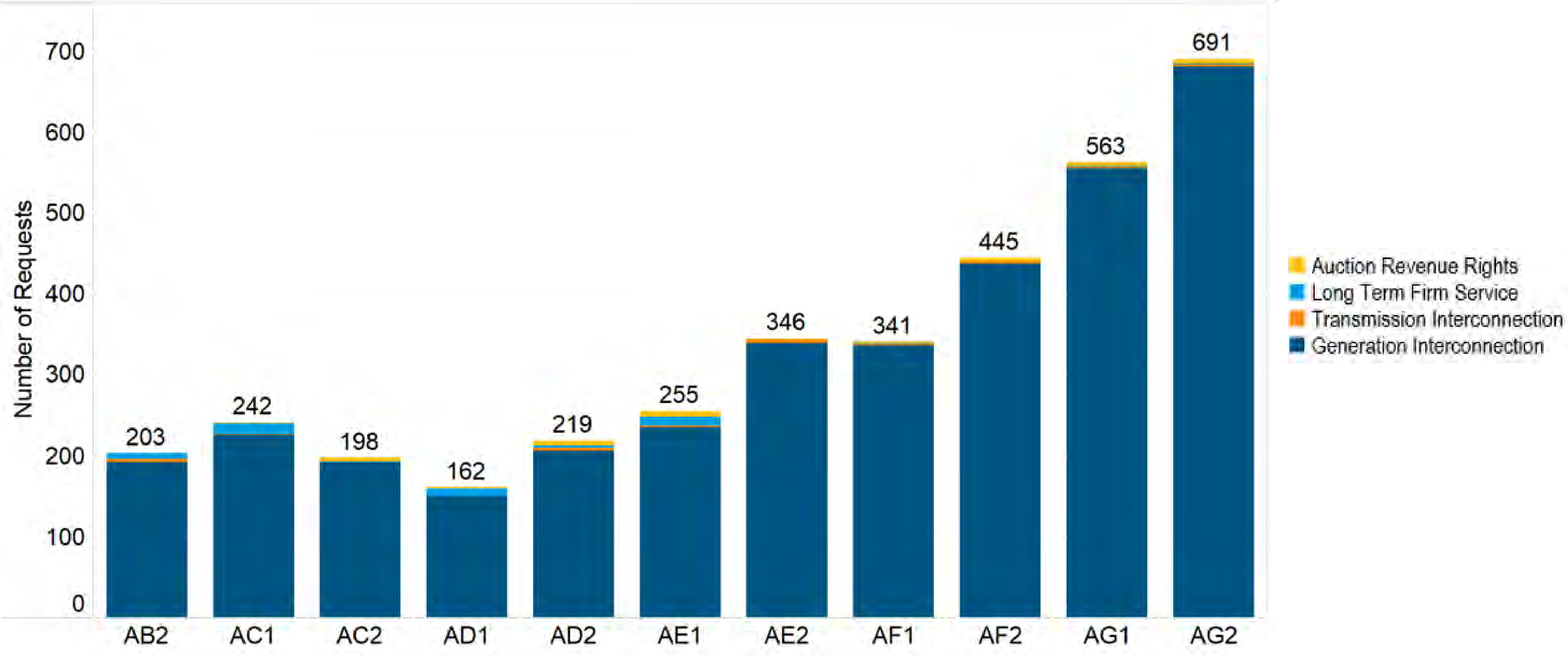
Overview

- Queue Trends: AB2 (November 2015) – AG2 (March 2021)
- AG2 Queue Overview

Note: Data provided is a snapshot of the Interconnection Queue as of April 30, 2021

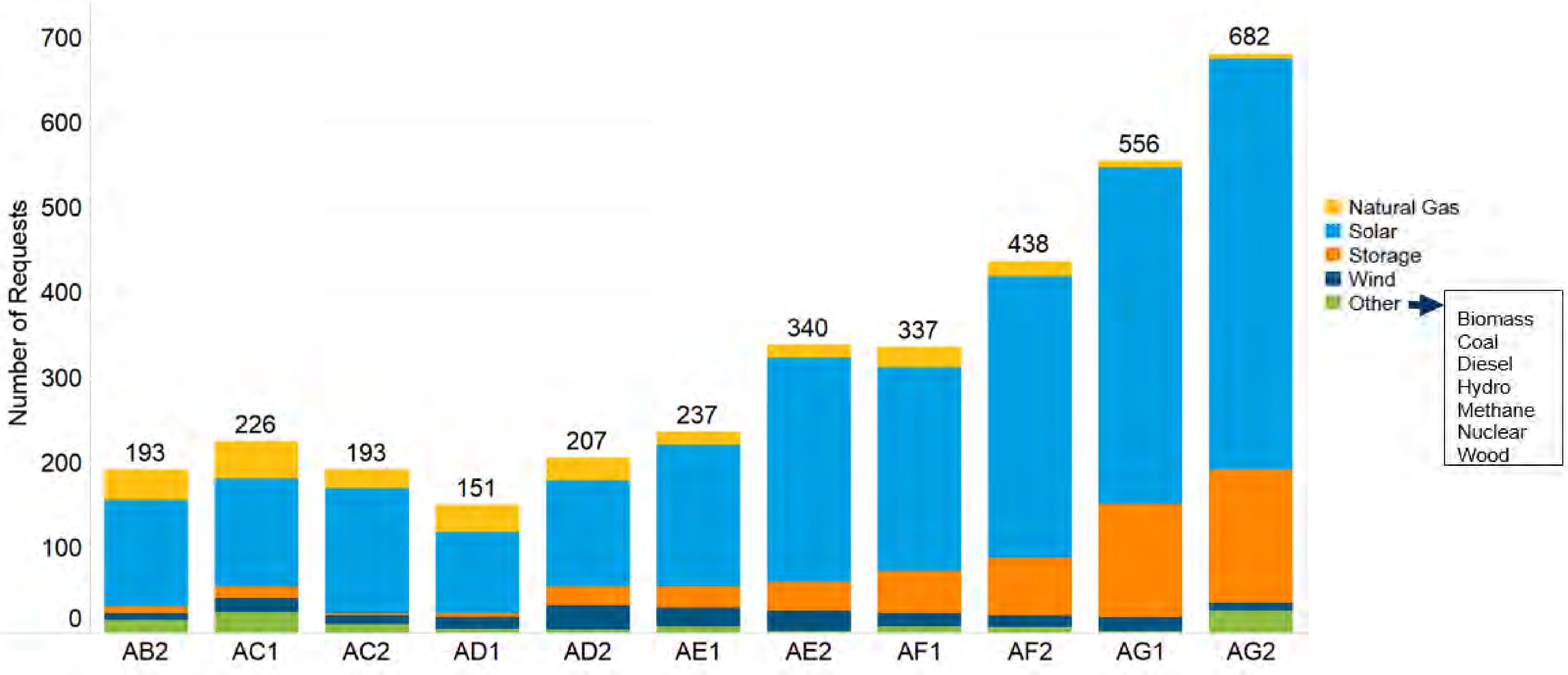
Recent Queue Trends: AB2 – AG2

Total New Service Requests by Application Type



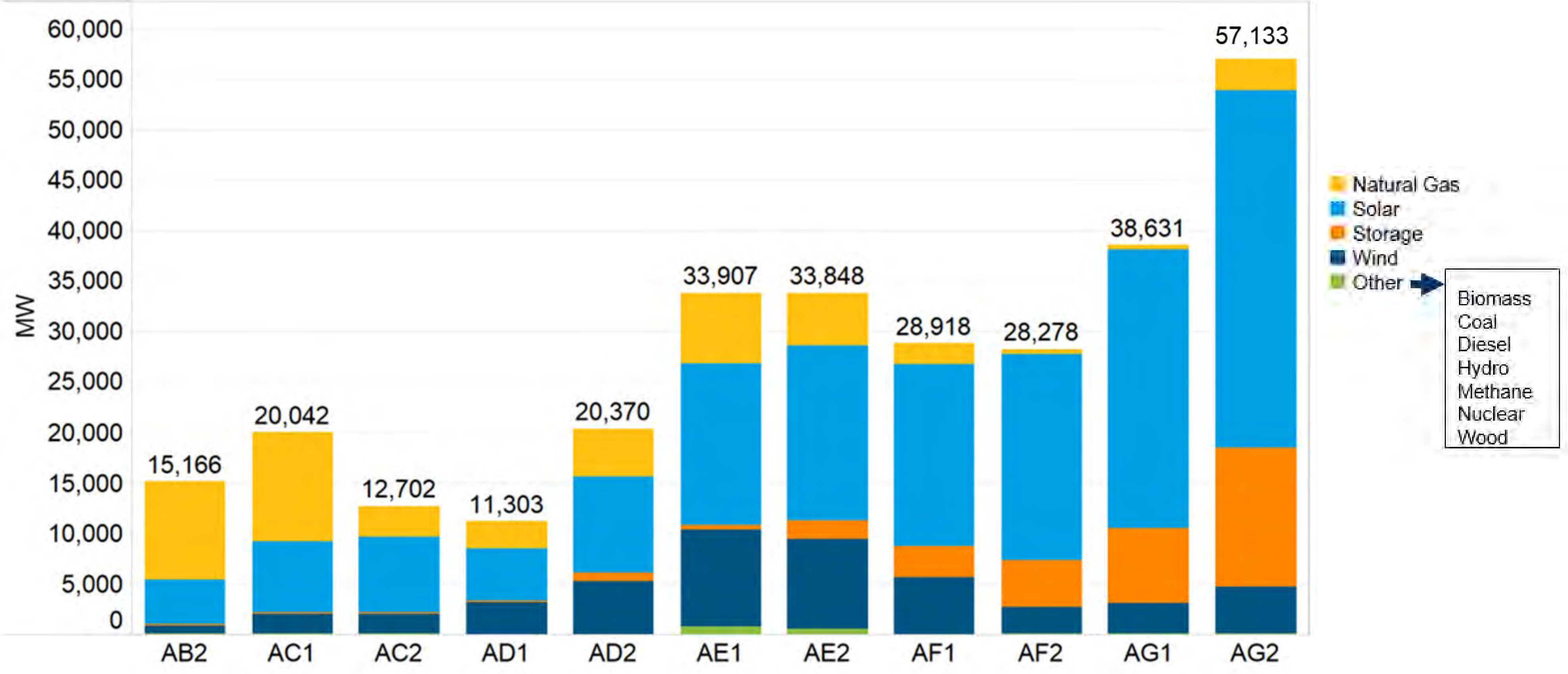
Recent Queue Trends: AB2 –AG2

Generation Interconnection Requests – Total Number



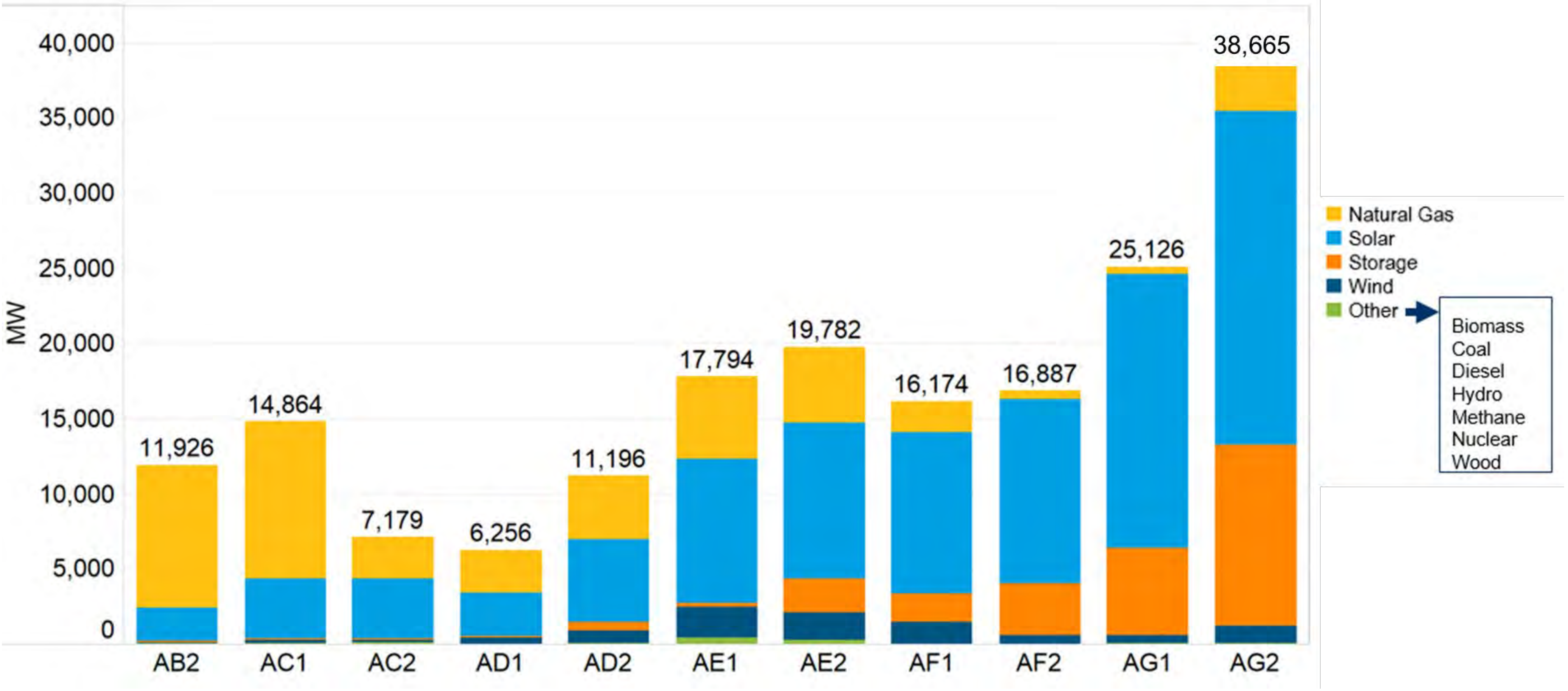
Recent Queue Trends: AB2 – AG2

Generation Interconnection Requests – Requested Energy



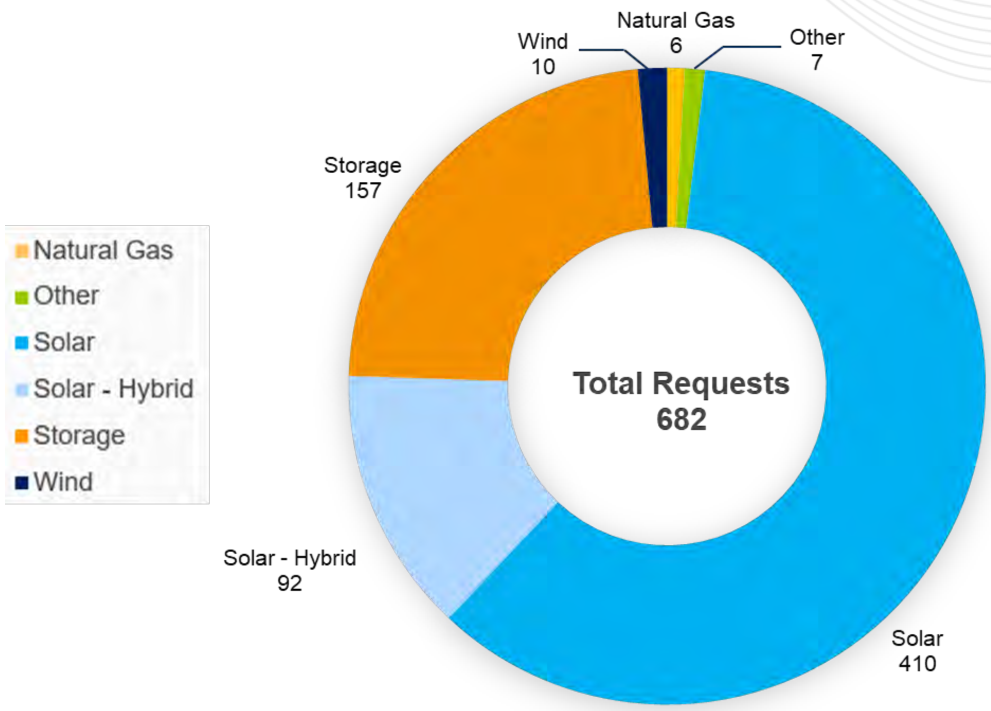
Recent Queue Trends: AB2 – AG2

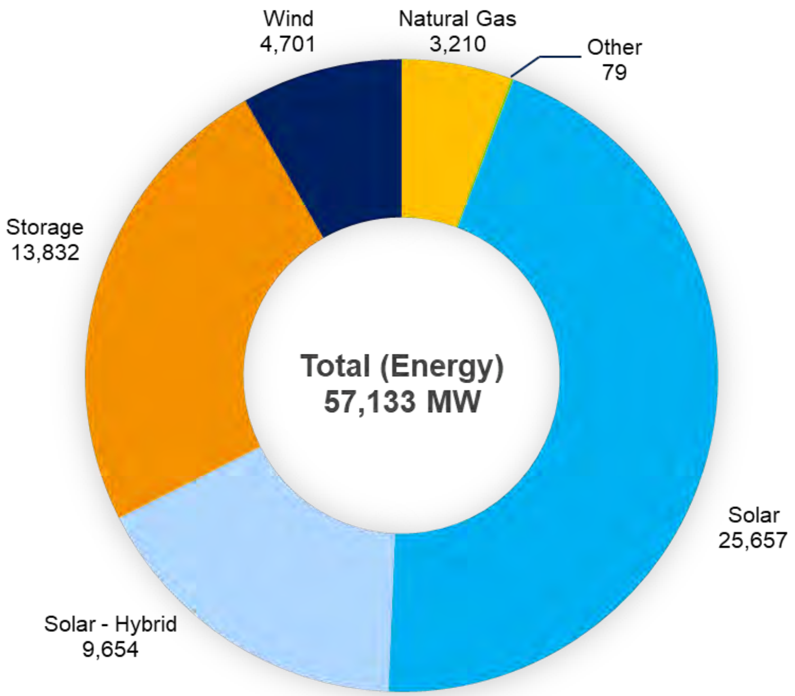
Generation Interconnection Requests – Requested CIRs



AG2 Queue Overview (Generation Interconnection Requests)

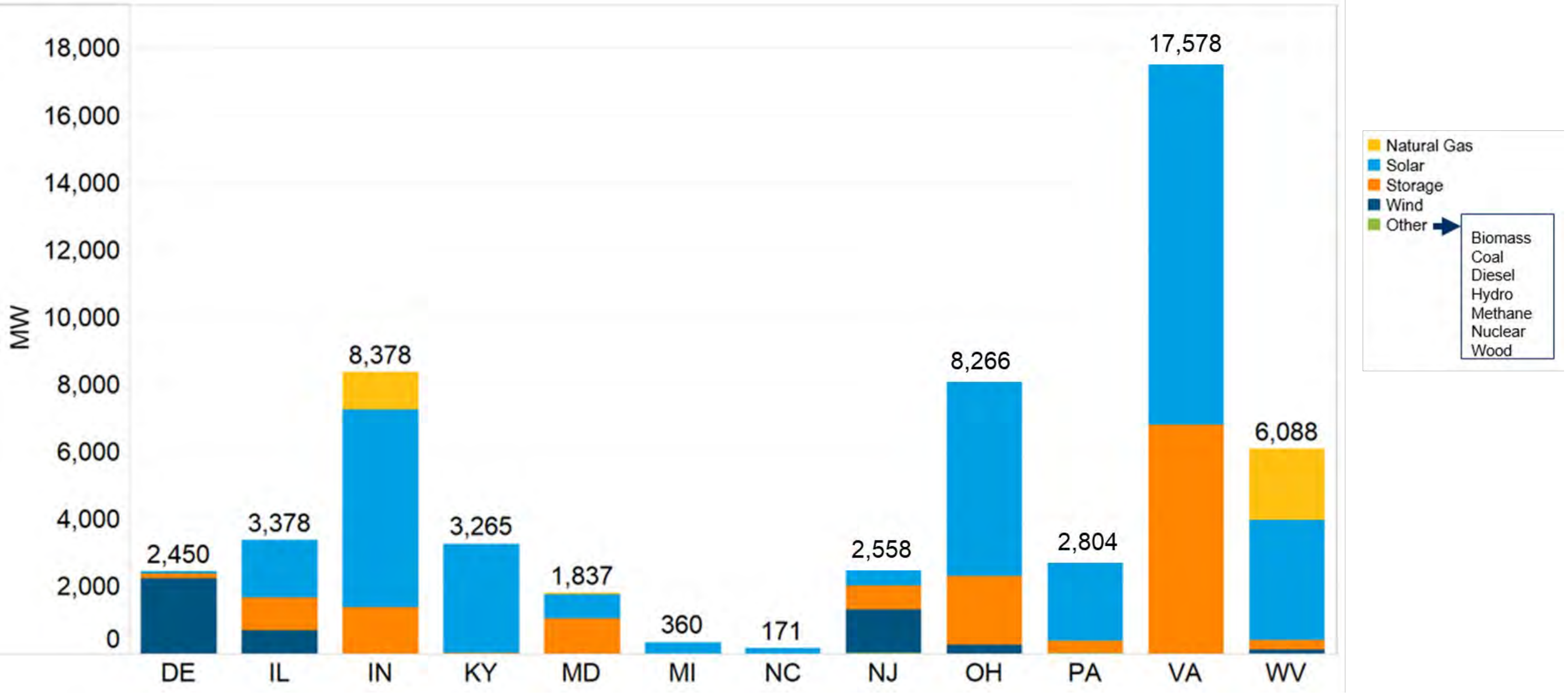
AG2 Queue Overview
Generation Interconnection Requests by Fuel Type





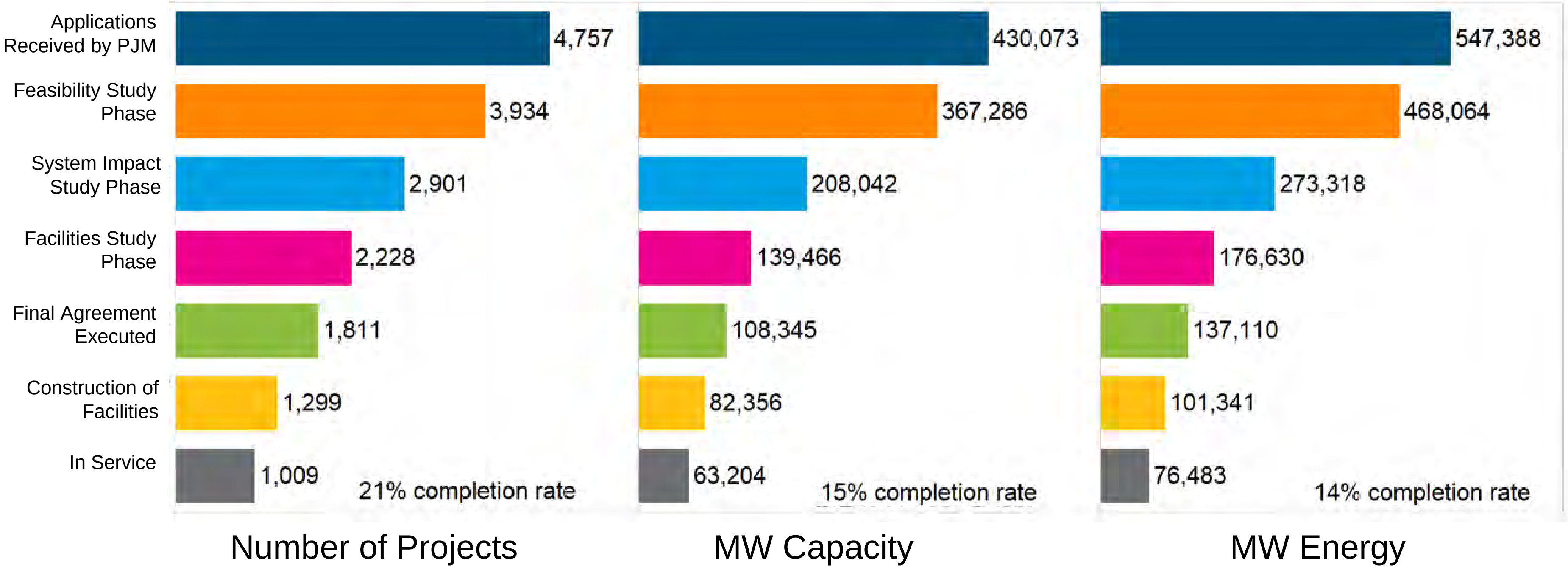
AG2 Queue Overview

All Fuel Types by State - Requested Energy



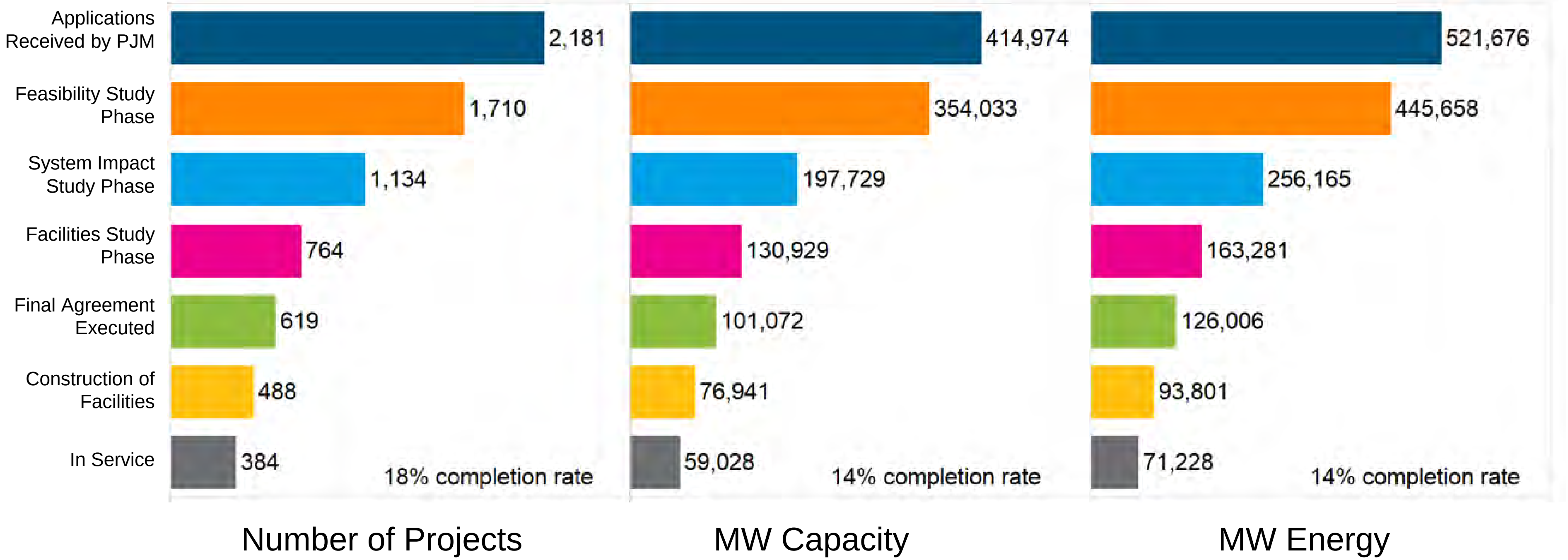
A – AG2 Queue and Active Queue Projects

Generation Phase Progression: A – AG2
All Generation Requests



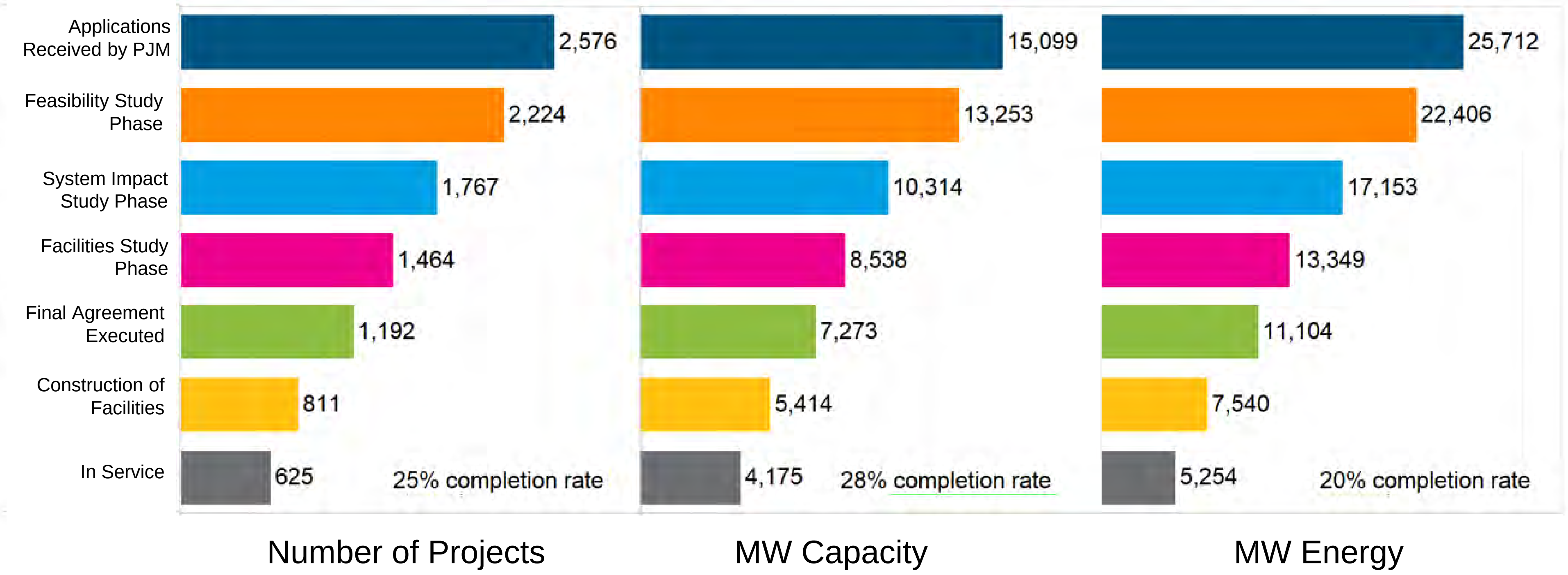
Generation Phase Progression: A – AG2

Large Generation Requests (> 20 MW)

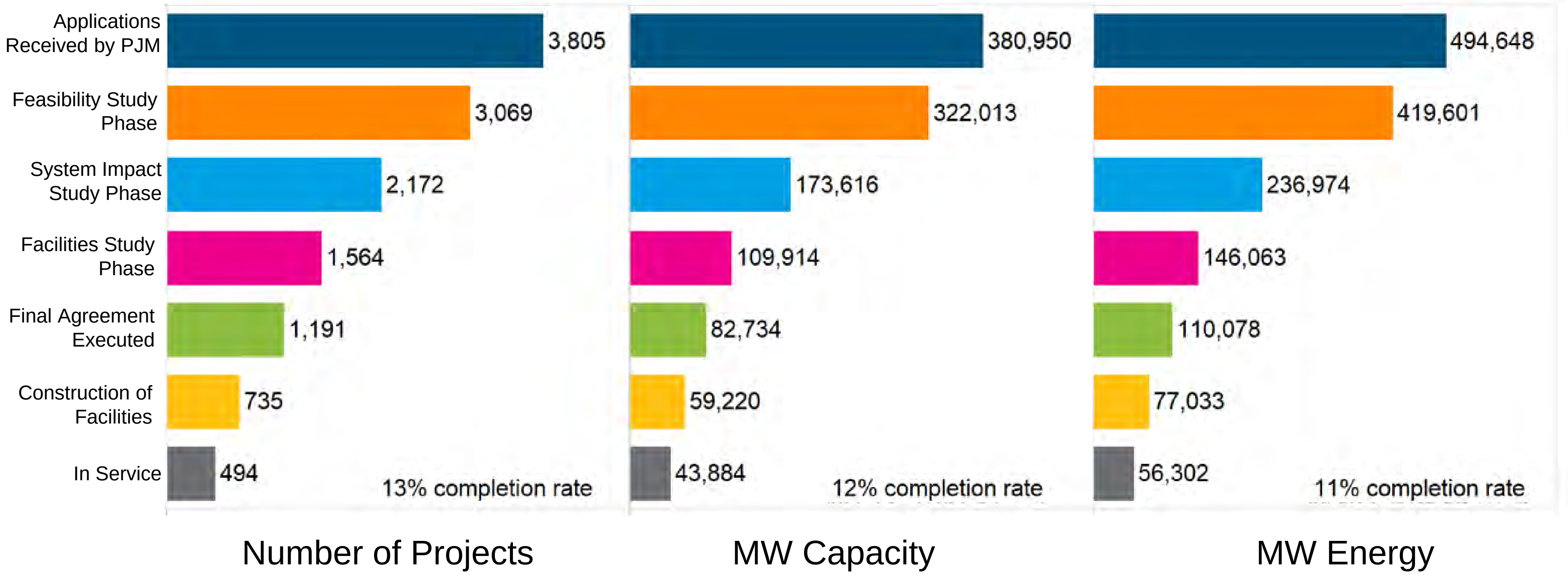


Generation Phase Progression: A – AG2

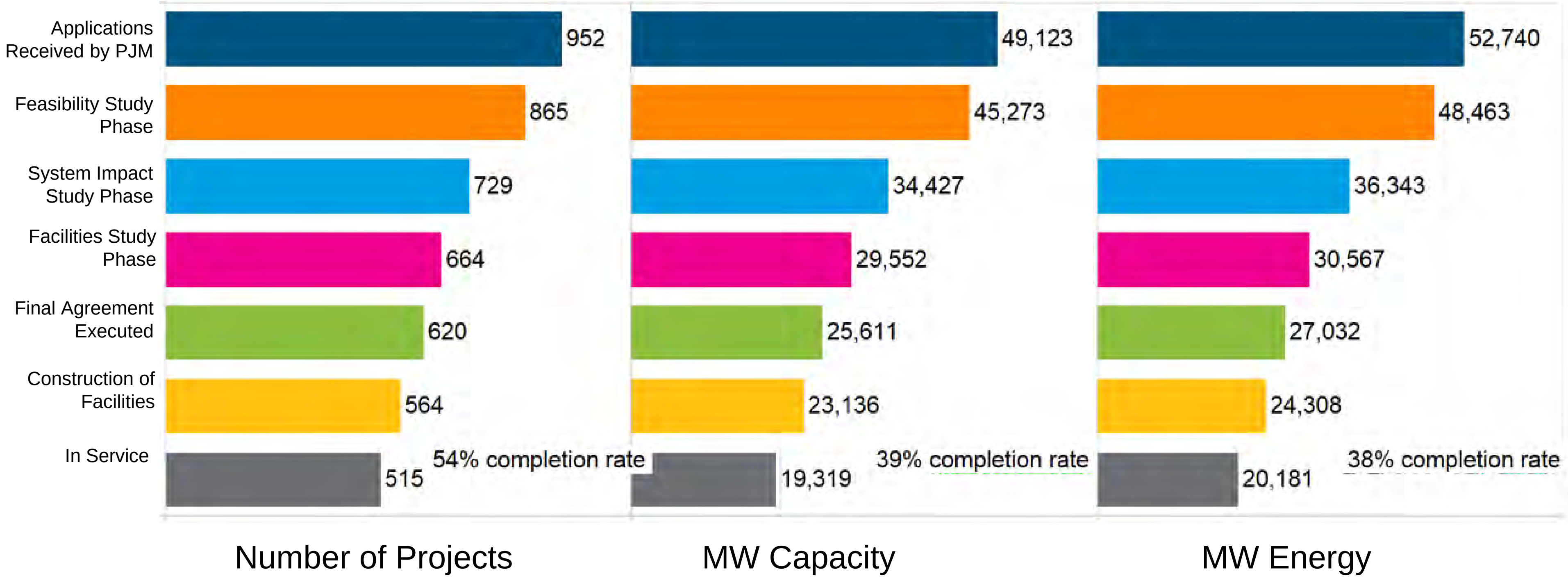
Small Generation Requests (≤ 20 MW)



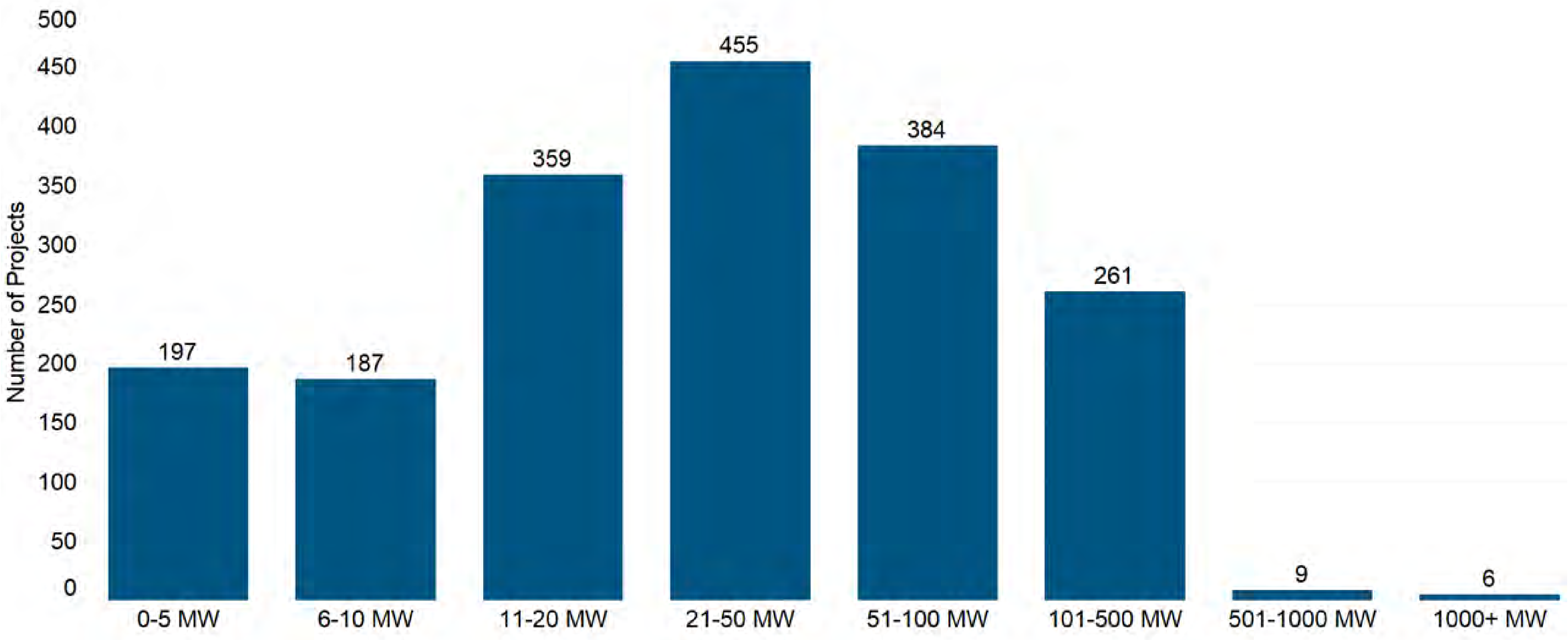
Generation Phase Progression: A – AG2
New Facility Requests



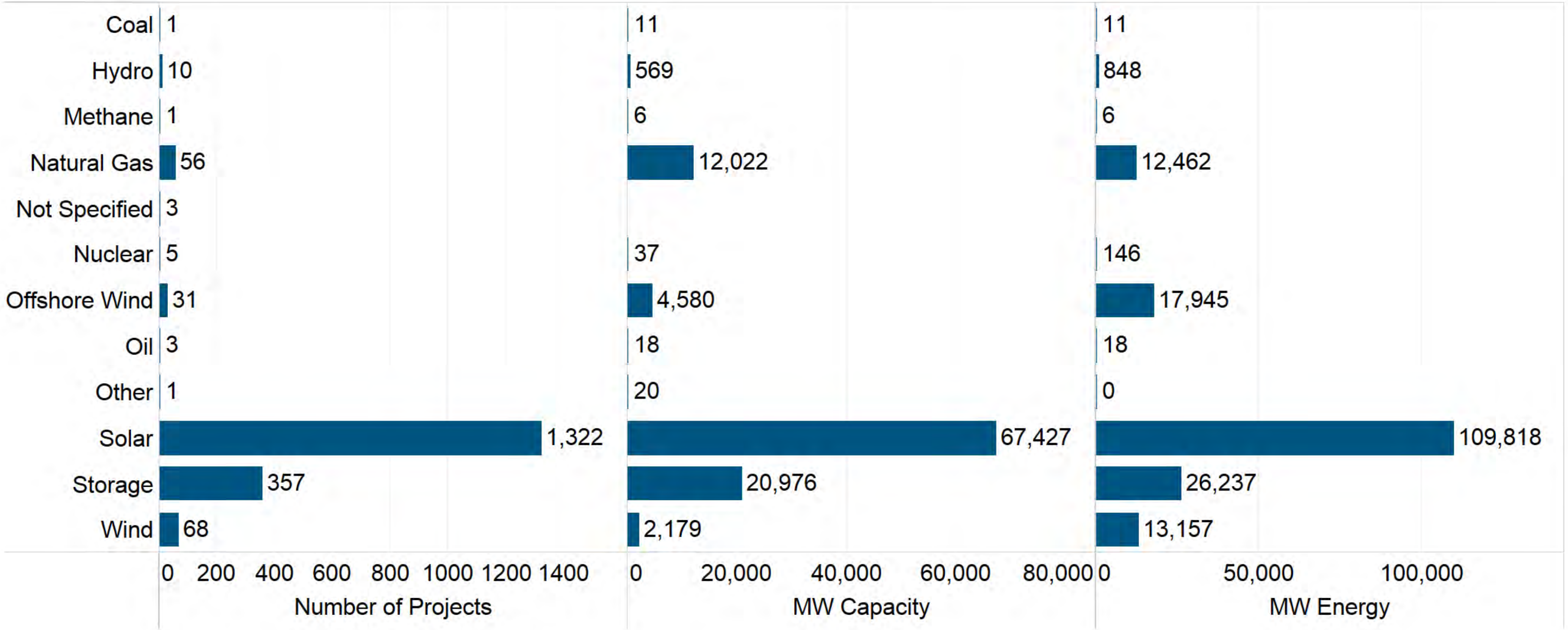
Generation Phase Progression: A – AG2
Uprate Generation Requests



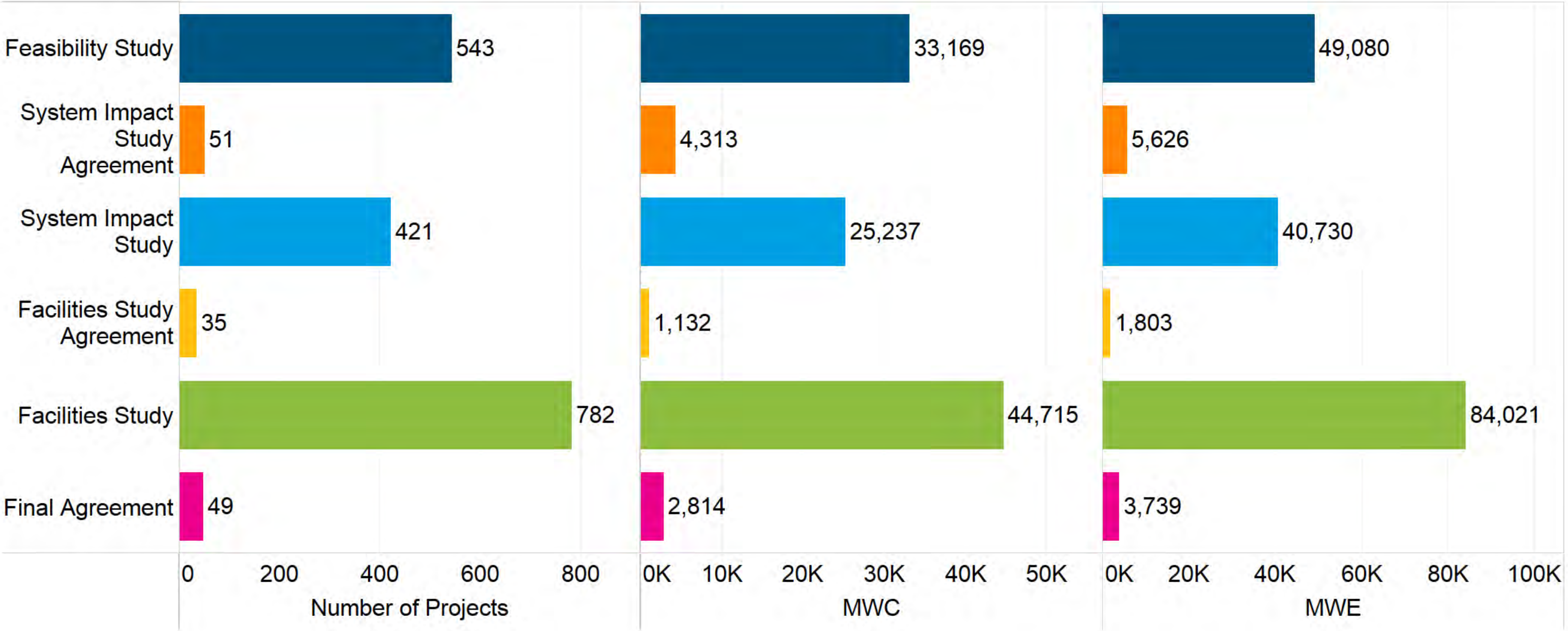
Active Projects in the Queue
Project Size Distribution



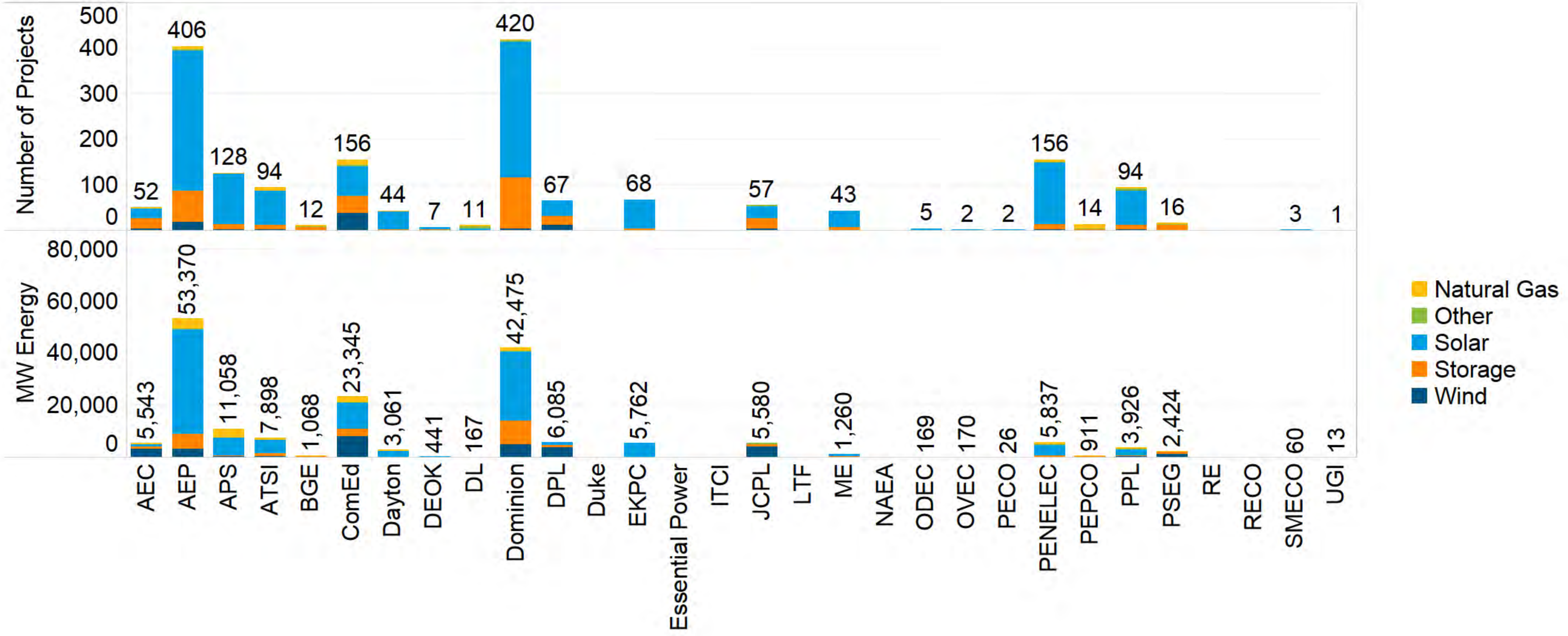
Active Projects in the Queue
Fuel Type Distribution



Active Projects in the Queue
Distribution of Study Phases



Active Projects in the Queue
Distribution by Transmission Owner Zone



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PJM Interconnection Queue Status Update

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

INDIANA MICHIGAN POWER
An AEP Company

OVEC ANALYSIS

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.

TABLE OF CONTENTS

Page

Jurisdiction and Venue 1

Relief Requested 1

Background 2

I. Overview of the Debtors' Business Operations 4

II. The OVEC Intercompany Power Purchase Agreement 5

Basis for Relief 6

A. Rejection of the OVEC ICPA is a Proper Exercise of the Debtors' Business Judgment 8

B. This Court Should Grant the Requested Relief *Nunc Pro Tunc* 12

Reservation of Rights 14

Notice 14

Conclusion 16

TABLE OF AUTHORITIES

Page(s)

Cases

In re Albrechts Ohio Inns, Inc.,
152 B.R. 496 (Bankr. S.D. Ohio 1993)........8

Class Five Nev. Claimants v. Dow Corning Corp. (In re Dow Corning Corp.),
280 F.3d 648 (6th Cir. 2002)........6

In re Enron Corp.,
No. 01 B 16034, 2006 WL 898033 (Bankr. S.D.N.Y. Mar. 24, 2006)........11

EOP-Colonnade of Dall. LP v. Faulkner (In re Stonebridge Techs., Inc.),
430 F.3d 260 (5th Cir. 2005)........13

In re Fashion Two Twenty, Inc.,
16 B.R. 784 (Bankr. N.D. Ohio 1982)........8, 9

In re Fleishman,
138 B.R. 641 (Bankr. D. Mass. 1992)........7

Grp. of Instl. Inv'rs v. Chi., M., St. P. & Pac. R.R. Co.,
318 U.S. 523 (1943)........11

In re HQ Glob. Holdings,
290 B.R. 507 (Bankr. D. Del. 2003)........9

Leasing Serv. Corp. v. First Tenn. Bank N.A.,
826 F.2d 434 (6th Cir. 1987)........7

In re Level Propane Gases, Inc.,
297 B.R. 503 (Bankr. N.D. Ohio 2003), *aff'd*, No. 02-16172, 2007 WL 1821723 (N.D. Ohio June 22, 2007)........9

Cal. ex rel. Lockyer v. FERC,
383 F.3d 1006 (9th Cir. 2004)........11

Midway Motor Lodge of Elk Grove v. Innkeepers Telemgmt. & Equip. Corp.,
54 F.3d 406 (7th Cir. 1995)........7

In re Mirant Corp., 318 B.R. 100, 107-08 *(N.D. Tex. 2004)*........11

Mirant Corp. v. Potomac Elec. Power Co. (In re Mirant Corp.),
378 F.3d 511 (5th Cir. 2004)........10, 11, 12, 13

In re Murexco Petrol., Inc.,
15 F.3d 60 (5th Cir. 1994) 6

In re N. Am. Royalties, Inc.,
276 B.R. 860 (Bankr. E.D. Tenn. 2002) 7

NLRB v. Bildisco & Bildisco,
465 U.S. 513 (1984)....................7, 8, 10, 11

Orion Pictures Corp. v. Showtime Networks, Inc. (In re Orion Pictures Corp.),
4 F.3d 1095 (2d Cir. 1993)....................8, 9

Osprey-Troy Officentre, LLC v. World All. Fin. Corp.,
502 F. App'x 455 (6th Cir. 2012) 7

Pa. Water & Power Co. v. Fed. Power Comm'n,
343 U.S. 414 (1952)....................11

Pac. Shores Dev., LLC v. At Home Corp. (In re At Home Corp.),
392 F.3d 1064 (9th Cir. 2004) 13, 14

In re Pesce Baking Co., Inc.,
43 B.R. 949 (Bankr. N.D. Ohio 1984) 9

Phar-Mor, Inc. v. Strouss Bldg. Assocs.,
204 B.R. 948 (N.D. Ohio 1997)....................8, 9

In re QSL Medina, Inc.,
No. 15-52722 (AMK) (Bankr. N.D. Ohio Dec. 15, 2015), ECF No. 105 13

In re Richendollar,
No. 04-70774, 2007 WL 1039065 (Bankr. N.D. Ohio Mar. 31, 2007) 8

Sharon Steel Corp. v. Nat'l Fuel Gas Distrib. Corp.,
872 F.2d 36 (3d Cir. 1989)....................9

Stewart Title Guar. Co. v. Old Republic Nat'l Title Co.,
83 F.3d 735 (5th Cir. 1996) 6

Summit Land Co. v. Allen (In re Summit Land Co.),
13 B.R. 310 (Bankr. D. Utah 1981) 9

Thinking Machs. Corp. v. Mellon Fin. Servs. Corp. # 1 (In re Thinking Machs. Corp.),
67 F.3d 1021 (1st Cir. 1995)....................13, 14

In re Trans World Airlines, Inc.,
261 B.R. 103 (Bankr. D. Del. 2001) 11

Westbury Real Estate Ventures, Inc. v. Bradlees Stores, Inc. (In re Bradlees Stores, Inc.),
194 B.R. 555 (Bankr. S.D.N.Y. 1996) 7

Statutes

11 U.S.C. § 105 .... 12, 13

11 U.S.C. § 365 .... 7, 8

11 U.S.C. § 1107 .... 1, 2

11 U.S.C. § 1108 .... 1, 2

16 U.S.C. § 824 10

28 U.S.C. §§ 157 and 1334 1

28 U.S.C. §§ 1408 and 1409 1

Other Authorities

3 Collier on Bankruptcy § 365.09[1] (15th ed. 2006) 8

Fed. R. of Bankr. P. 1007(d) 15

Fed. R. of Bankr. P. 1015(b) 2

Fed. R. of Bankr. P. 2002, 6006 and 9014 1

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.

[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 and Debtors in Possession

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

[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.

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[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

Judah L. Rose

INFRASTRUCTURE AND PROJECT FINANCE

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

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND SUMMARY 1

II. RECENT WHOLESALE POWER PRICING TRENDS 23

III. UPDATED MARKET MODELING ASSUMPTIONS 27

IV. UPDATED MODELING ASSUMPTIONS – COAL 38

V. UPDATED MODELING ASSUMPTIONS – OTHER 44

VI. ELECTRICITY PRICE PROJECTIONS – ALL-HOURS ELECTRICAL ENERGY 52

VII. POWER PLANT DISPATCH AND REALIZED ELECTRICAL ENERGY PRICES 59

VIII. ELECTRICITY PRICE PROJECTIONS – CAPACITY PRICES AND FIRM POWER PRICES 62

IX. PROJECTIONS OF REVENUES AND GROSS MARGINS 69

X. PROJECTIONS OF DEMAND CHARGES AND NET MARGINS 72

XI. CONCLUSION 78

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.

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[2] Allegheny Energy Supply Company LLC, Appalachian Power Company, Buckeye Power Generating LLC, The Dayton Power and Light Company, Duke Energy Ohio Inc., FirstEnergy Solutions Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company comprise of the sponsoring companies.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony contains the following sections:

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

Q. WHAT SPECIFIC FORECASTS ARE YOU PROVIDING?

A. I provide the following forecasts:

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

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

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

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

Q. HOW IS YOUR SUMMARY ORGANIZED?

A. My summary has four main parts:

- **Approach and Updated Assumptions;**
- **PJM Market Price Forecast** – Firm Electricity, Electrical Energy, Capacity Prices and Annual Price Volatility;
- **Plant Specific Forecasts** – Dispatch, Revenues, Gross Margins, Demand Charges, Net Margins;
- **Annual Cost and Price Volatility and Hedge Value;** and
- **Conclusions**

I.1 APPROACH

Q. SUMMARIZE YOUR APPROACH.

A. My approach has three parts. First, I compare the costs of power from Clifty Creek and Kyger Creek with the costs of purchasing the same amount of power from the market under ICF's Base Case conditions. I base my recommendations on the operations of Clifty Creek and Kyger Creek on the cash going-forward economics *i.e.,* excluding sunk costs. I also compare market purchases and the costs of OVEC power including sunk costs. I do not opine on the treatment of sunk costs in terms of recoverability, though I present perspectives on their treatment.

Second, I consider a second scenario using the EIA natural gas price reference case forecast instead of ICF's updated natural gas price base case forecast. This is the only public forecast that uses a theoretically correct methodology. Gas prices are an important uncertainty. This is especially relevant because ICF forecasts that over the next 8 years, demand for natural gas will increase so much that we expect US production will increase from 74 Bcfd to 98 Bcfd – (*i.e.* by 32%). This demand will come from numerous sources including major increases in natural gas exports.

Third, I compare the annual volatility of the costs of the two procurement approaches (*i.e.,* ICPA contract and market) basing the comparison on recent historical data. I do not opine on what if any trade-offs should be made between cost and volatility to the extent the results indicate there is a trade-off, though I do believe expected costs and cost volatility are both appropriate considerations.

Q. SUMMARIZE YOUR ASSUMPTION UPDATES.

A. Key updates include:

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

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

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

I.2 MARKET PRICE FORECASTS

Q. WHAT ARE FIRM ALL-HOURS POWER PRICES?

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

[3] 2025 is a full year for comparison.
[4] The capacity price is averaged across the 8760 hours of the year and added to the all-hours average electrical energy price. The result is a single $/MWh price often referred to as a unit contingent firm price or a bundled price.

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

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

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

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

[5] 2025 is considered full year.

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

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

- **Extreme Conditions** - The winter of 2015/2016 was one of the warmest in US history, and oil prices fell from $108/barrel in early 2014 to less than $30/Barrel in early 2016.
- **Historically Low Prices** - AEP Dayton electrical energy prices were the lowest since 2005, and Henry Hub, Louisiana natural gas prices were the lowest since 1999. Gas prices at Dominion South, another gas price market location north of Pittsburgh, were the lowest ever.
- **Evidence of Non-sustainability** – Between 2014 and 2016, US drilling for oil and gas dropped 75 percent and there were over 100 bankruptcies in small and mid-size oil and gas producers.
- **Price Increases Between 2016 and 2017 and 2018 YTD** – Many spot and forward prices increased over the course of 2016, 2017 through early 2018. The increase in 2017 occurred in spite of 2017 being a warm winter compared to average.
- **Modeling** - Computer model simulations capturing the long-term dynamics of the power and related industries support higher average prices than 2016. This modeling also accounts for general inflation, long-term conditions including regulatory changes, rising demand for gas, etc.

Q. WHAT ARE ELECTRICAL ENERGY PRICES?

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

Q. WHAT IS YOUR FORECAST OF ELECTRICAL ENERGY PRICES?

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

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

A. The key drivers of higher electrical energy prices over time include higher natural gas prices, and higher energy demand as weather returns to average conditions, load growth and retirements, potential new regulations, new unit costs and general inflation (*i.e.,* average economy wide inflation measured using GDP deflator).

Q. WHAT IS YOUR CAPACITY PRICE FORECAST?

A. PJM purchases and OVEC can sell capacity three years forward and the price is expressed as $/MW-day, $/kW-month and $/kW-year. I forecast that [BEGIN CONFIDENTIAL] [redacted] Thus, my updated forecast is [redacted] than my forecast in the Direct Testimony for 2018 to 2025. [END CONFIDENTIAL] This reflects several factors. First, there are changes in historical PJM auction results which I directly incorporate in my forecast. This includes the more than 80% increase in PJM RTO capacity prices the May 2018 auction relative to the May 2017 auction. Second, my post auction forecasts are modestly lower. This is because lower gas prices lead to higher dispatch for marginal capacity price setting units, and I assumed slightly lower physical heat rates for new combined cycles for delivery in 2024/2025.

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

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

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

Q. DOES YOUR CAPACITY PRICE FORECAST INCREASE OVER TIME?

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

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

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

[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.

<u>I.3 POWER PLANT FORECASTS</u>

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

[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]

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22 Partial year 2025.

[BEGIN CONFIDENTIAL]

Exhibit 1

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

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

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

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

Exhibit 2

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

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

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

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

[END CONFIDENTIAL]

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

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

[redacted] [END CONFIDENTIAL]

I.4 CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS?

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

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

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

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

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

Accordingly, I conclude the plants should continue to operate.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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

II. RECENT WHOLESALE POWER PRICING TRENDS

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

A. Exhibit 3 below provides wholesale electrical energy market prices for the period from 2009 to 2017.[23] Electrical energy prices are set node-by-node, but PJM reports load weighted zonal averages for demand nodes and hubs and simple averages for supply nodes. Between 2012 and 2017, AEP Dayton Hub all-hours electrical energy prices averaged $33.8/MWh in real 2016 dollars, and $33.1/MWh in nominal dollars. Historically, Clifty Creek and Kyger Creek nodal prices averaged 5.5 percent lower compared to AEP Dayton Hub's all-hours prices. In nominal dollars, the range of AEP Dayton Hub's prices was from $44.1/MWh in 2014 to $27.8/MWh in 2016 or $16.2/MWh – *i.e.,* the lowest prices were in 2016. As noted, 2015/2016 winter weather was among the warmest on record and electrical energy prices and natural gas prices were very low.

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

Exhibit 3
Historical Electrical Energy Prices – All-Hours ($/MWh)

Source	**Year**	**AEP-Dayton Hub**	**Clifty and Kyger Creek Nodal Average[1]**	**AEP-Dayton Hub**	**Clifty and Kyger Creek Nodal Average[1]**
		(2016$/MWh)	**(2016$/MWh)**	**(Nom$/MWh)**	**(Nom$/MWh)**
Historical	2009	36.8	34.9	33.0	31.3
	2010	41.4	39.4	37.6	35.8
	2011	41.8	39.2	38.7	36.4
	2012	33.1	32.0	31.2	30.2
	2013	36.5	33.7	35.0	32.4
	2014	45.1	41.5	44.1	40.5
	2015	31.9	29.9	31.5	29.5
	2016	27.8	26.6	27.8	26.6
	2017	28.6	27.7	29.2	28.2
	2018 YTD	35.1	32.6	36.6	34.0
	2012-2017	**33.8**	**31.9**	**33.1**	**31.2**
	2009-2017	**35.9**	**33.9**	**34.2**	**32.3**

Source: SNL Financial, Ventyx
Notes:
1) The nodal prices for Clifty Creek and Kyger Creek from 2009 to 2015 represents OVEC node. PJM updated its LMP Bus Model on Dec 9, 2015 and added CLFTY and KYGER nodes. 2016 represents average of CLFTY and KYGER nodal prices. These are 8760 hour nodal averages.
2) 2018 YTD represents trades from Jan 1 – May 11, 2018

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

A. As mentioned above, forward PJM capacity prices reflect PJM's auction for three-year forward capacity delivery for June 1 through May 31 of the following year. The auction is called the Base Residual Auction (BRA) and is held in May of each year. Thus, calendar year 2018 capacity prices reflect auction results in May 2014 for the period January 1, 2018 - May 31, 2018, and in May 2015 for June 1, 2018- December 31, 2018. Exhibit 4 shows calendarized 2013 to May 31, 2022 capacity prices from PJM auctions. Over the last 9 years, capacity prices in the RTO sub-region of PJM averaged approximately $36.5/kW-yr in nominal dollars (approximately $100/MW-day). As noted, most of the historic capacity prices do not reflect full implementation of the capacity performance arrangements. Even when PJM procured in the May 2017 auction 100 percent capacity performance product, it used the lowest possible penalty rate from the perspective of the number of hours of emergency; the penalty rate is too low, and hence, bids for the willingness to be exposed to the penalties are too low.

Exhibit 4
PJM Capacity Prices for the RTO Zone (Nom$/kW-yr)

RTO Capacity Prices (Nom$/kW-yr)				
Delivery Period	**Base Residual Auction**	**1st Incremental Auction**	**2nd Incremental Auction**	**3rd Incremental Auction**
2013	8.4	6.8	3.5	1.2
2014	31.0	4.2	6.4	6.0
2015	48.1	10.0	32.8	38.6
2016	33.3	19.3	27.3	25.9
2017	34.6	27.0	10.4	8.5
2018	53.3	18.6	14.7	13.0
2019	46.4	15.1	NA	NA
2020	31.5	NA	NA	NA
2021	41.4	NA	NA	NA
Jan 2022-May 2022	51.1	NA	NA	NA
2013-2021 Average	**36.5**	**14.4**	**15.8**	**15.6**
2018-2021 Average	**43.2**	**16.8**	**14.7**	**13.0**

Source: PJM

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

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

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

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

Source: PJM, Ventyx

Q. HOW ARE GENERATORS COMPENSATED FOR THE COSTS OF PROVIDING ANCILLARY SERVICES?

A. Generators are compensated for ancillary services through either cost-based rates, or the PJM market. The principal payments are to power plants acting as operating reserves which can be quickly deployed by system operators, and give up the opportunity to participate in the energy market. Ancillary service revenues are a very small portion of total costs.

III. UPDATED MARKET MODELING ASSUMPTIONS

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

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

Q. SUMMARIZE YOUR UPDATES.

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

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

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

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

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

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

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

Q. WHAT HAPPENED?

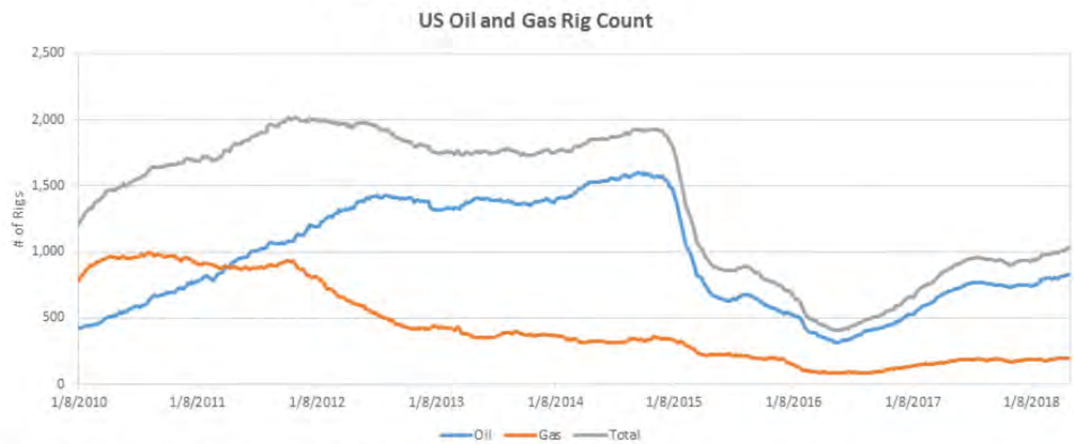
A. All of the above happened. Gas prices recovered 18 to 40 percent depending on location. In 2017, Henry Hub spot prices averaged $2.97/MMBtu, 18 percent above 2016 levels, and Dominion South averaged $2.11/MMBtu, 40 percent above 2016 levels of $1.50/MMBtu (see Exhibit 6). In the year to date 2018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

Exhibit 6
Historical Dominion South Gas Prices

	Henry Hub		Dominion South		Basis WRT HH	
Year	(Nom$/ MMBtu)	(2016$/ MMBtu)	(Nom$/M MBtu)	(2016$/ MMBtu)	(Nom$/ MMBtu)	(2016$/ MMBtu)
2005	8.69	10.53	9.24	11.19	0.55	0.67
2006	6.73	7.91	7.08	8.33	0.35	0.42
2007	6.96	7.97	7.41	8.48	0.44	0.51
2008	8.88	9.97	9.33	10.48	0.45	0.50
2009	3.95	4.40	4.26	4.75	0.31	0.35
2010	4.40	4.84	4.60	5.07	0.21	0.23
2011	4.00	4.32	4.13	4.46	0.13	0.14
2012	2.76	2.92	2.78	2.95	0.02	0.03
2013	3.73	3.89	3.52	3.67	-0.20	-0.21
2014	4.36	4.47	3.30	3.38	-1.06	-1.09
2015	2.64	2.67	1.50	1.52	-1.14	-1.16
2016	2.51	2.51	1.50	1.50	-1.00	-1.00
2017	2.97	2.91	2.11	2.07	-0.86	-0.84
2018 YTD	2.90	2.78	2.50	2.40	-0.40	-0.39
Average 2005-2017	**4.81**	**5.33**	**4.68**	**5.22**	**-0.14**	**-0.11**
Average 2009-2017	**3.48**	**3.66**	**3.08**	**3.26**	**-0.40**	**-0.40**
Average 2012-2017	**3.16**	**3.23**	**2.45**	**2.51**	**-0.71**	**-0.71**

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

Exhibit 7
US Oil and Gas Rig Count



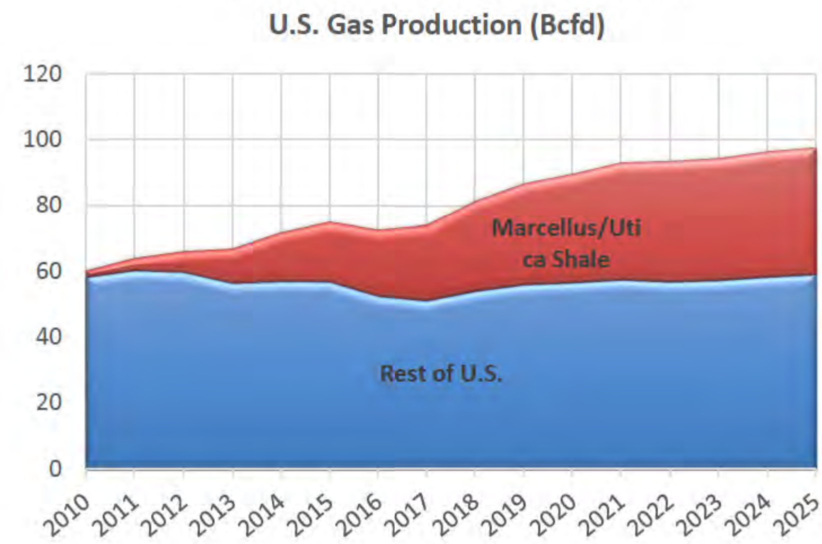
Source: Baker Hughes, from January 8, 2010 to May 4, 2018

Exhibit 8
Marcellus & Utica Gas Production (Bcfd)

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

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

Exhibit 9
Marcellus & Utica Gas Production (Bcfd)



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

Q. WHAT ARE YOUR UPDATED GAS PRICE FORECASTS?

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

Q. WHY IS YOUR CURRENT GAS PRICE FORECAST LOWER?

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

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

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

[redacted]

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]

[END CONFIDENTIAL]

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

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

Exhibit 12

[BEGIN CONFIDENTIAL] [redacted]

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

[redacted]

Notes:

[redacted]

[END CONFIDENTIAL]

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

A. Yes, there will be very large year-by-year volatility due to weather and economic and industry cycles. Volatility will be especially pronounced in demand areas, also referred to as market areas, where there can be large imbalances between natural gas demand for and availability of natural gas delivery infrastructure. I emphasize my forecasts are of expected or probability weighted values and the yearly volatility around these forecasts are expected.

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

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

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

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

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

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

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

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

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

BEGIN CONFIDENTIAL] Exhibit 14

[redacted]

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

[redacted] [END CONFIDENTIAL]

IV. UPDATED MODELING ASSUMPTIONS – COAL

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

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

Exhibit 15
Historical NAPP and Illinois Basin Coal Spot Prices.

	NAPP, Upper Ohio River Barge, 12500 Btu/lb, > 6 lb/MMBtu Sulfur				Illinois Basin Barge, 11000 Btu/lb, 5 lb/MMBtu Sulfur			
	Nom$		2016$		Nom$		2016$	
Year	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2012	49.1	1.96	52.0	2.08	44.5	2.02	47.1	2.14
2013	55.0	2.20	57.3	2.29	42.4	1.93	44.2	2.01
2014	57.5	2.30	58.9	2.36	45.2	2.05	46.3	2.10
2015	50.6	2.02	51.3	2.05	40.0	1.82	40.5	1.84
2016	40.5	1.62	40.5	1.62	35.8	1.63	35.8	1.63
2017	36.3	1.45	35.6	1.42	35.5	1.61	34.8	1.58
2018 YTD	36.6	1.46	35.1	1.40	38.3	1.74	36.7	1.67
Avg (2012-2017)	**46.5**	**1.86**	**47.2**	**1.89**	**40.2**	**1.83**	**40.8**	**1.85**

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

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

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

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

Exhibit 16
Historical Delivered Coal Costs for the OVEC Plants

	Kyger Creek		**Clifty Creek**	
Year	**2016$**	**Nom$**	**2016$**	**Nom$**
2012	2.28	2.15	2.90	2.73
2013	2.20	2.11	2.75	2.63
2014	2.15	2.09	2.99	2.92
2015	1.94	1.92	2.53	2.49
2016	1.91	1.91	2.23	2.23
2017	1.80	1.84	2.20	2.24
2018 Year to Date	1.76	1.83	1.98	2.07
Average (2012-2017)	**2.05**	**2.00**	**2.60**	**2.54**

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

Q. WHAT IS YOUR FORECAST OF COMMODITY COAL PRICES?

A. Over time (see Exhibit 17), I forecast coal prices will remain relatively flat in real terms on average over time. For example, Northern Appalachia high sulfur 6 lb. SO_2/MMBtu coal prices are projected [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[BEGIN CONFIDENTIAL] Exhibit 17

[redacted]

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

[redacted]

Exhibit 20

[redacted]

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

[redacted]

[END CONFIDENTIAL]

V. UPDATED MODELING ASSUMPTIONS – OTHER

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

A. Yes.

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

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

Q. HOW DID THE UPDATED DEMAND FORECAST CHANGE?

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

Exhibit 21
PJM RTO Zone Demand Forecast

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

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

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

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

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

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

Exhibit 22
PJM Demand Resource Participation in Base Residual Auctions

DR Type	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
ILR	2,107	2,110	2,108	2,110	1,594	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
DR Cleared	128	536	893	939	1,365	7,047	9,282	14,118	14,833	12,408	10,975	11,084	10,348	7,820	11,126
EE Cleared	NA	NA	NA	NA	NA	569	679	822	923	1,117	1,339	1,247	1,515	1,710	2,832
Total DSM	**2,235**	**2,646**	**3,001**	**3,049**	**2,959**	**7,616**	**9,961**	**14,941**	**15,755**	**13,525**	**12,314**	**12,331**	**11,863**	**9,531**	**13,958**
Demand Requirements															
Peak Demand	137,421	139,806	142,177	144,592	142,390	144,857	160,634	164,758	163,168	165,412	164,479	161,418	157,188	153,915	152,647
DR as% of Demand Requirements															
% of Peak	1.6%	1.9%	2.1%	2.1%	2.1%	5.3%	6.2%	9.1%	9.7%	8.2%	7.5%	7.6%	7.5%	6.2%	9.1%
% of Target Reserves	11%	13%	14%	14%	13%	34%	39%	59%	63%	52%	48%	49%	46%	37%	58%
Target Reserve Margin %	15.0%	15.0%	15.0%	15.5%	15.5%	16.2%	15.3%	15.3%	15.4%	15.6%	15.7%	15.7%	16.5%	16.6%	15.8%

Source: PJM-ISO

[BEGIN CONFIDENTIAL]

Exhibit 23

[redacted]

[END CONFIDENTIAL]

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

A. Yes.

Q WHAT ARE YOUR ASSUMPTIONS ABOUT FIRM PJM BUILDS AND RETIREMENTS?

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

Exhibit 24
PJM - Firm Builds and Retirements (GW)

	Year	Retirements (MW)	Firm Builds - Combined Cycle (MW)
PJM	2010	786	0
	2011	1,325	1,215
	2012	7,027	1,418
	2013	2,859	0
	2014	2,967	2,246
	2015	9,464	1,724
	2016	393	3,710
	2017	2,084	3,325
	2010-2017	**26,903**	**13,638**
	2018	5,377	7,167
	2019	2,631	4,501
	2020	2,062	2,109
	2021	3,058	620
	2018-2021	**13,128**	**14,397**
	2010-2021	**40,031**	**28,035**

Source: PJM-ISO; SNL Financial, Ventyx

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

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

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

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

Q. WHAT ARE YOU ASSUMING ABOUT NON-CO_2 ENVIRONMENTAL REGULATIONS?

A. My forecast tracks a number of non-CO_2 environmental regulations including CSAPR for SO_x and NO_x control, the Mercury and Air Toxic Standards Rule for mercury control, Section 316(b) for control of cooling water withdrawals, ash handling is controlled through coal combustion residual regulations, and the impacts of EPA's Effluent Limitations Guidelines are also included. In general, the current administration is likely to significantly change environmental regulations in favor of coal generation. Coal generation will benefit from the greatly decreased near-term likelihood of national CO_2 emission regulations and other regulatory initiatives that increase the cost of operating coal plants. ICF has updated its forecasts to account for this development.

Q. WHAT ARE YOU ASSUMING REGARDING CAPITAL AND FINANCING COSTS FOR NEW BUILDS?

A. New combined cycle plants are assumed to be available in summer 2021, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] In equilibrium in the long-term, an important driver of scarcity or capacity prices is the annual costs of new entry (*i.e.,* entry by a new natural gas-fired combined cycle). [BEGIN CONFIDENTIAL] [redacted]

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[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)

	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]

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]	[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.

[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]

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]

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]

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

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

A. Annual wholesale market price volatility is [BEGIN CONFIDENTIAL] [redacted] than volatility in the costs of Clifty Creek and Kyger Creek. The range of average delivered coal cost over the 2012 to 2017 was $2/MMBtu to $2.5/MMBtu or $0.5/MMBtu. This was [redacted] of the average. Total costs ranged from [redacted]. This [redacted] of the average. This compares favorably to the [redacted] for the firm power price – *i.e.,* the volatility of the market is approximately [redacted] [END CONFIDENTIAL]

XI. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS?

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

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

I have not conducted a detailed review of the OVEC contract, and its complex regulatory history, and defer to the PUCO's expertise on how sunk costs be treated with regard to rate recovery for Duke Energy Ohio. However, I note an argument in support of Duke Energy Ohio's request is that the unconventional and unique power supply agreement is the legacy of prudent decisions made long before deregulation. Indeed, it is my understanding that the decision was primarily a response to an urgent national need for the industry to work collaboratively on an important matter of national defense.

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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

Judah L. Rose ICF

Senior Vice President, Managing Director

Education

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

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

Awards and Recognition

One of ICF's Distinguished Consultants, an honorary title given to only three of ICF's 5,000 employees

Experience Overview

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF. He Chairs its Energy Advisory Services Line of Business and works closely with its ICF's Wholesale Power practice and Chairs its Energy Advisory Services Line of Business.

Mr. Rose has approximately 40 years of experience in the energy industry including in electricity market design, power generation, power fuels – coal, natural gas, renewables, environmental compliance, planning, finance, forecasting, and transmission. His clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, consumers and Independent Power Producers. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 5,000 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative.

Mr. Rose frequently provides expert testimony and litigation support. He has provided testimony in over 130 instances in 45 venues including scores of state, federal, international, and other legal proceedings. Mr. Rose has testified in over 24 states and provinces, at the Federal Energy Regulatory Commission, in numerous court settings and internationally.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community in restructuring and financing.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. He has also appeared in TV interviews.

Accomplishment Highlights

- Close to 40 years of experience in the energy industry
- Testimony in over 130 instances in scores of state, federal, international, and other legal proceedings
- Frequent counselor on restructuring and financing of new and existing power plants

Selected Press Interviews

Television "The Most With Allison Stewart," MSNBC, "Blackouts in NY and St. Louis & ongoing Energy Challenges in the Nation," July 25, 2006
CNBC Wake-Up Call, August 15, 2003
Wall Street Journal Report, July 25, 1999
Back to Business, CNBC, September 7, 1999

Journals: Electricity Journal
Energy Buyer Magazine
Public Utilities Fortnightly
Power Markets Week

Magazines: Business Week
Power Economics
Costco Connection

Newspapers: Denver Post
Rocky Mountain News
Financial Times Energy
LA Times
Arkansas Democratic Gazette
Galveston Daily News
The Times-Picayune
Pittsburgh Post-Gazette
Power Markets Week

Wires: Associated Press
Bridge News
Dow Jones Newswires

Testimony

133. Expert Declaration, in support of (1) The motion for preliminary and permanent injunction against FERC (2) The motion for entry of an order authorizing to reject certain energy contracts (3) The motion for entry of an order authorizing to reject a certain multi-party intercompany power purchase agreement with the Ohio Valley Electric Corporation. On behalf of FES, March 31, 2018.
132. Direct Testimony, Case No. 17-872-EL-RDR, On behalf of Duke Energy Ohio, March 31, 2017131. Affidavit, In Answer to Complaint of Next Era and PSEG Companies, FERC Docket No. EL16-93-000, Testimony on New Gas Pipelines, and Wholesale Gas and Power Market Design, July 28, 2016. On behalf of Eversource.
130. Rebuttal Testimony, Support for an Electric Security Plan Filing, on behalf of Ohio Edison Company, The Cleveland Electric illuminating Company, The Toledo Edison Company, Case No. 14-1297-EL-SSO, October 20, 2015.
129. Demand Resource Pricing Testimony on behalf of P3, Docket ER15-852-000, February, 13, 2016
128. Damages Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, January 5, 2015.

127. Responsive Testimony of Judah L. Rose on Behalf of Oklahoma Energy Results, LLC December 16, 2014, CAUSE NO. PUD 201400229
126. Rebuttal Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, November 26, 2014.
125. Statement of Opinions on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, October 30, 2014.
124. Direct Testimony, CO_2 price forecasts provided to IPL for use in their compliance analysis, as well as, support for the probabilities assigned to the Coal Combustion Residuals ("CCR"), 316 (b) and Effluent Limitation Guidelines ("ELG") regulations for use in IPL analysis in support of their Compliance Project, Indianapolis Power & Light Company, IURC Cause No. 44540, October 14, 2014.
123. Direct Testimony, Support for an Electric Security Plan Filing, Ohio Edison Company (FirstEnergy), August 4, 2014.
122. Rebuttal Testimony, Valuation of Mad River Power Plant, FirstEnergy, February 27, 2014.
121. Expert Report, Computation of Future Damages, Breach of Wolf Run Coal Sales Agreement, prepared for Meyer, Unkovic, and Scott, LLP, filed February 12, 2014.
120. Supplemental Direct Testimony of Judah Rose on behalf of National Grid and Northeast Utilities, Petition of New England Power Company d/b/a/ National Grid for Approval to Construct and Operate a New 345 kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69J, August 8, 2013.
119. Rebuttal Testimony of Judah Rose on Behalf of Monongahela Power Company, The Potomac Edison Company, Petition for Approval of a Generation Resource Transaction and Related Relief, Case No. 12-1571 – E – PC, May 17, 2013.
118. Direct Testimony of Judah Rose on behalf of New England Power Company d/b/a National Grid before the Commonwealth Of Massachusetts Energy Facilities Siting Board and Department Of Public Utilities, Petition of New England Power Company d/b/a National Grid for Approval to Construct and Operate a New 345kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69, Docket EFSB 12-1/D.P.U. 12-46/47, November 21, 2012.
117. Direct Testimony for the Narragansett Electric Company d/b/a National Grid (Interstate Reliability Project), Before the State of Rhode Island Public Utilities Commission, Energy Facility Siting Board ("Siting Board") Notice of Designation to Public Utilities Commission ("PUC") to Render an Advisory Opinion on need and cost-justification for Narragansett Electric d/b/a National Grid's proposal to construct and alter major energy facilities in RI, the "Interstate Reliability Project", RIPUC Docket No. 4360, November 21, 2012
116. Sur-Surrebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, September 21, 2012.
115. Rebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, July 30, 2012.

114. Direct Testimony, The Connecticut Light & Power Company, Application for a Certificate of Environmental Compatibility and Public Need for the Connecticut Portion of the Interstate Reliability Project that traverses the municipalities of Lebanon, Columbia, Coventry, Mansfield, Chaplin, Hampton, Brooklyn, Pomfret, Killingly, Putnam, Thompson, and Windham, which consists of (a) new overhead 345-kV electric transmission lines and associated facilities extending between CL&P's Card Street Substation in the Town of Lebanon, Lake Road Switching Station in the Town of Killingly, and the Connecticut/Rhode Island border in the Town of Thompson; and (b) related additions at CL&P's existing Card Street Substation, Lake Road Switching Station, and Killingly Substation, Docket No. 424, July 17, 2012.
113. Direct Testimony, Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, February 9, 2012.
112. Rebuttal Testimony, Otter Tail Power Company, Before the Office of administrative Hearings, for the Minnesota Public Utilities Commission, In The Matter of Otter Tail Power Company's Petition for an Advance Determination of Prudence for its Big Stone Air Quality Control System Project, September 7, 2011.
111. Rebuttal Testimony, on behalf of Arizona Public Service, In the Matter of the Application of Arizona Public Service Company for Authorization for the Purchase of Generating Assets from Southern California Edison, and for an Accounting Order, Docket No. E-01345A-10-0474, June 22, 2011.
110. Direct Testimony, Duke Energy Ohio, Inc., Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service, Case No. 11-XXXX-EL-SSO. Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. Case No. 11-XXXX-EL-ATA. Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. Case No. 11-XXXX-EL-UNC, June 20, 2011.
109. Direct Testimony, Manitoba Hydro Power Sales Contracting Strategy, U.S. Power Markets, Manitoba Hydro Drought Risks, Modeling, Forecasting and Planning, Selected Risk and Financial Issues, Governance, Trading and Risk Related Comments Before the Public Utilities Board of Manitoba, February 22, 2011.
108. Sur-rebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2010-0356, January 12, 2011.
107. Rebuttal Report Concerning Coal Price Forecast for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed December 6, 2010.
106. Direct Testimony of Judah Rose on behalf of Duke Energy Ohio In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service, Case No. 10-2586-EL-SSO, filed November 15, 2010.
105. Updated Forecast, Coal Price Report for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed October 18, 2010.

104. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 29, 2010.
103. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 16, 2010.
102. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line Oklahoma LLC to conduct Business as an Electric Utility in the State of Oklahoma, Cause No.PUD 201000075, July 16, 2010.
101. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line LLC for a Certificate of Public Convenience and Necessity to Operate as an Electric Transmission Public Utility in the State of Arkansas, Docket No. 10-041-U, June 4, 2010.
100. Supplemental Testimony on Behalf of Entergy Arkansas, Inc., In the Matter of Entergy Arkansas, Inc., Request for a Declaratory Order Approving the Addition of the Environmental Controls Project at the White Bluff Steam Electric Station Near Redfield, Arkansas, Docket No. 09-024-U, July 6, 2009.
99. Rebuttal Testimony on Behalf of TransEnergie, Canada, Province of Quebec, District of Montreal, No.: R-3669-2008-Phase 2, FERC Order 890 and Transmission Planning, July 3, 2009.
98. Sur-rebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, before the Missouri Public Service Commission, In the Matter of the Application of KCP&L GMO, Inc. d/b/a KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2009-0090, April 9, 2009.
97. Hawaii Structural Ironworkers Pension Trust Fund v. Calpine Corporation, Case No. 1-04-CV-021465, Assessment of Calpine's April 2002 Earnings Projections, March 25, 2009.
96. Coal Price Report for Harrison Coal Plant, Allegheny Energy Supply Company, LLS and Monongahela Power Company versus Wolf Run Mining Company, Anker Coal Group, etc., Civil Action. No. GD-06-30514, In the Court of Common Pleas, Allegheny County, Pennsylvania, February 6, 2009.
95. Supplemental Direct Testimony of Judah Rose, on behalf of Southwestern Electric Power Company, In the Matter of the Application of Southwestern Electric Power Company for Authority to Construct a Natural-Gas Fired Combined Cycle Intermediate Generating Facility in the State of Louisiana, Docket No. 06-120-U, December 9, 2008.
94. Rebuttal Testimony of Judah Rose on behalf of Kelson Transmission Company, LLC re: Application of Kelson Transmission Company, LLC For A Certificate of Convenience and Necessity For the Amended Proposed Canal To Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, And Orange Counties, SOAH Docket No. 473-08-3341, PUCT Docket No. 34611, October 27, 2008.
93. Testimony of Judah Rose, on behalf of Redbud Energy, LP, in Support of Joint Stipulation and Settlement Agreement, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of the Purchase of the Redbud Generating Facility and Authorizing a Recovery Rider, Cause No. PUD 200800086, September 3, 2008.

92. Direct Testimony of Judah L. Rose on behalf of Duke Energy Carolinas, In the Matter of Advance Notice by Duke Energy Carolinas, LLC, of its Intent to Grant Native Load Priority to the City of Orangeburg, South Carolina, and Petition of Duke Energy Carolinas, LLC and City of Orangeburg, South Carolina for Declaratory Ruling With Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority, Docket No. E-7, SUB 858, August 15, 2008.
91. Affidavit filed on behalf of Public Service of New Mexico pertaining to the Fuel Costs of Southwest Public Service for Cost-of-Service and Market-Based Customers, August 11, 2008.
90. Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio, Inc., Before the Public Utilities Commission of Ohio, In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan, July 31, 2008.
89. Rebuttal Testimony, Judah L. Rose on Behalf of Duke Energy Carolinas, in re: Application of Duke Energy Carolinas, LLC for Approval of Save-A-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket No. E-7, Sub 831, July 21, 2008.
88. Updated Analysis of SWEPCO Capacity Expansion Options as Requested by Public Utility Commission of Texas, on behalf of SWEPCO, June 27, 2008.
87. Direct Testimony of Judah L. Rose on Behalf of Nevada Power/Sierra Pacific Electric Power Company, Docket No. 1, Public Utilities Commission of Nevada, Application of Nevada Power/Sierra Pacific for Certificate of Convenience and Necessity Authorization for a Gas-Fired Power Plant in Nevada, May 16, 2008.
86. Rebuttal Testimony of Judah L. Rose on Behalf of the Advanced Power, Commonwealth of Massachusetts, Before the Energy Facilities Siting Board, Petition of Brockton Power Company, LLC, EFSB 07-7, D.P.U. 07-58 & 07-59, May 16, 2008.
85. Supplemental Rebuttal Testimony on Commissioner's Issues of Judah L. Rose for Southwestern Electric Power Company, on behalf of Southwestern Electric Power Company, PUC Docket No. 33891, Public Utilities Commission of Texas, May 2008.
84. Supplemental Direct Testimony on Commissioners' Issues of Judah Rose for Southwestern Electric Power Company, for the Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas, SOAH Docket No. 473-07-1929, PUC Docket No. 33891, Public Utility Commission of Texas, April 22, 2008.
83. Rebuttal Testimony of Judah Rose, In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008.
82. Rebuttal Report of Judah Rose, Ohio Power Company and AEP Power Marketing Inc. vs. Tractebel Energy Marketing, Inc. and Tractebel S.A. Case No. 03 CIV 6770, 03 CIV 6731 (S.D.N.Y.), January 28, 2008.
81. Proposed New Gas-Fired Plant, on behalf of AEP SWEPCO, 2007.
80. Rebuttal Report, Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 21, 2007.
79. Expert Report. Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 19, 2007.

78. Application of Duke Energy Carolina, LLC for Approval of Energy Efficiency Plan Including an Energy Efficiency Rider and Portfolio of Energy, Docket No. 2007-358-E, Public Service Commission of South Carolina, December 10, 2007.
77. Independent Transmission Cause No. PUD200700298, Application of ITC, Public Service of Oklahoma, December 7, 2007.
76. Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code š8-1-2.5-1, et. Seq. for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance With Ind. Code šš8-1-2.5-1 et seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the PowerShare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Cause Earnings and Expense Tests, Indiana Utility Regulatory Commission, Cause No. 43374, October 19, 2007.
75. Rebuttal Testimony, Docket No. U-30192, Application of Entergy Louisiana, LLC For Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery, October 4, 2007.
74. Direct Testimony of Judah Rose on Behalf of Tucson Electric Power Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, July 2, 2007.
73. Supplemental Testimony on behalf of Southwestern Electric Power Company before the Arkansas Public Service Commission, In the Matter of Application of Southwestern Electric Power Company for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation, and Maintenance of a Coal-Fired Base Load Generating Facility in the Hempstead County, Arkansas, dated June 15, 2007, Docket No. 06-154-U.
72. Rebuttal Testimony, Causes No. PUD 200500516, 200600030, and 20070001 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, June 2007.
71. Rebuttal Testimony on behalf of Duke Energy Indiana, IGCC Coal Plant CPCN, Cause No. 43114 before the Indiana Utility Regulatory Commission, May 31, 2007.
70. Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 2007.
69. Rebuttal Testimony on behalf of Florida Power & Light Company In Re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant, Docket No. 070098-EL, March 30, 2007.
68. Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 2007.
67. Direct Testimony for Southwestern Electric Power Company, Before the Louisiana Public Service Commission, Docket No. U-29702, in re: Application of Southwestern

Electric Power Company for the Certification of Contracts for the Purchase of Capacity for 2007, 2008, and 2009 and to Purchase, Operate, Own, and Install Peaking, Intermediate and Base Load Coal-Fired Generating Facilities in Accordance with the Commission's General Order Dated September 20, 1983. Consolidated with Docket No. U-28766 Sub Docket B in re: Application of Southwestern Electric Power Company for Certification of Contracts for the Purchase of Capacity in Accordance with the Commission's 'General Order of September 20, 1983, February 2007.

66. Second Supplemental Testimony on Behalf of Duke Energy Ohio Before the Public Utility Commission of Ohio, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA, February 28, 2007.
65. Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, February 2007.
64. Supplemental Testimony on behalf of Duke Energy Carolinas before the North Carolina Utilities Commission in the Matter of Application of Duke Energy Carolinas, LLC for Approval for an Electric Generation Certificate of Public Convenience and Necessity to Construct Two 800 MW State of Art Coal Units for Cliffside Project, Docket No. E7, SUB790, December 2006.
63. Expert Report, Chapter 11, Case No. 01-16034 (AJG) and Adv. Proc. No. 04-2933 (AJG), November 6, 2006.
62. IGCC Coal Plant, Testimony on behalf of Duke Energy Indiana, Cause No. 43114, October 2006.
61. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106 OAL Docket No. PUC-1874-05, Supplemental Testimony March 20, 2006.
60. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Surrebuttal Testimony December 27, 2005.
59. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, November 14, 2005.
58. Brazilian Power Purchase Agreement, confidential international arbitration, October 2005.
57. Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.
56. Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.
55. Cost of Service and Fuel Clause Issues, Testimony on behalf of Public Service of New Mexico, FERC Docket No. EL05-151-000, September 15, 2005.
54. Cost of Service and Peak Demand, FERC, Responsive Testimony on behalf of Public Service of New Mexico, August 23, 2005, Docket No. EL05-19.
53. Prudence of Acquisition of Power Plant, Testimony on behalf of Redbud, September 12, 2005, No. PUD 200500151.
52. Proposed Fuel Cost Adjustment Clause, FERC, Docket Nos. EL05-19-002 and ER05-168-001 (Consolidated), August 22, 2005.
51. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU, FERC, Docket EC05-43-000, May 27, 2005.

50. New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.
49. Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.
48. New Air Emission Regulations and Investment in Coal Power Plants, supplemental testimony on behalf of PSI, January 21, 2005, Causes 42622 and 42718.
47. Damages Due to Rejection of Tolling Agreement Including Discounting, January 10, 2005, CONFIDENTIAL.
46. Discount rates that should be used in estimating the damages to GTN of Mirant's bankruptcy and subsequent abrogation of the gas transportation agreements Mirant had entered into with GTN, December 15, 2004. CONFIDENTIAL
45. New Air Emission Regulations and Investment in Coal Power Plants, testimony on behalf of PSI, November 2004, Causes 42622 and 42718.
44. Rebuttal Testimony of Judah Rose on behalf of PSI, "Certificate of Purchase as of yet Undetermined Generation Facility" Cause No. 42469, August 23, 2004.
43. Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, Mohave Coal Plant Economics, June 4, 2004.
42. Supplemental Testimony "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, May 20, 2004.
41. "Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Coal-Fired Generating Station," May 14, 2004.
40. "Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.
39. "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.
38. "Valuation of Selected MIRMA Coal Plants, Acceptance and Rejection of Leases and Potential Prejudice to Leasors" Federal Bankruptcy Court, Dallas, TX, March 24, 2004 CONFIDENTIAL.
37. "Certificate of Purchase as of yet Undetermined Generation Facility", Cause No. 42469 for PSI, March 23, 2004.
36. "Ohio Edison's Sammis Power Plant BACT Remedy Case", In the United States District Court of Ohio, Southern Division, March 8, 2004.
35. "Valuation of Power Contract," January 2004, confidential arbitration.
34. "In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, Coal-Fired and Gas-Fired Market Values, July 21, 2003.
33. "In the Supreme Court of British Columbia", July 8, 2003. CONFIDENTIAL
32. "The Future of the Mohave Coal-Fired Power Plant – Rebuttal Testimony", California P.U.C., May 20, 2003.

31. "Affidavit in Support of the Debtors' Motion", NRG Bankruptcy, Revenues of a Fleet of Plants, May 14, 2003. CONFIDENTIAL
30. "IPP Power Purchase Agreement," confidential arbitration, April 2003.
29. "The Future of the Mohave Coal-Fired Power Plant", California P.U.C., March 2003.
28. "Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL
27. "Power Purchase Agreement Valuation", Confidential Arbitration, October 2002.
26. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02."
25. "Cause No. 42200 - in support of PSI's petition for authority to recover through retail rates on a timely basis. Filed on 7/30/02."
24. "Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."
23. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002."
22. "Analysis of an IGCC Coal Power Plant", Minnesota state senate committees, January 22, 2002.
21. "Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002
20. "Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001
19. "The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000
18. "Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL
17. "Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL
16. Application of FirstEnergy Corporation for approval of an electric Transition Plan and for authorization to recover transition revenues, Stranded Cost and Market Value of a Fleet of Coal, Nuclear, and Other Plants, Before PUCO, Case No. 99-1212-EL-ETP, October 4, 1999 and April 2000.
15. "Issues Related to Acquisition of an Oil/Gas Steam Power plant in New York", September 1999 Affidavit to Hennepin County District Court, Minnesota
14. "Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages", Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.
13. "Power Prices." Testimony in confidential contract arbitration, July 1998.
12. "Horizontal Market Power in Generation." Testimony to New Jersey Board of Public Utilities, May 22, 1998.
11. "Basic Generation Services and Determining Market Prices." Testimony to the New Jersey Board of Public Utilities, May 12, 1998.
10. "Generation Reliability." Testimony to New Jersey Board of Public Utilities, May 4, 1998.
9. "Future Rate Paths and Financial Feasibility of Project Financing." Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.
8. "Stranded Costs of PSE&G." Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.

7. "Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code." Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.
6. "Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy." Testimony to Louisiana Public Service Commission, December 1996.
5. "Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.
4. "Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.
3. "Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.
2. "Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public Service Commission, May 1993.
1. "The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (Der), Hearings on Fuel Diversity and Environmental Protection, December 1992.

Selected Speaking Engagements

115. Rose, J.L., The Polar Vortex, System Reliability and Recent PJM Developments, American Municipal Power Conference, October 28, 2014.
114. Rose, J.L., Wholesale power Market Price Projection in California, Infocast, California Energy Summit, San Francisco, CA, May 28, 2014.
113. Rose, J.L., The Polar Vortex and Future Power system Trends, National Coal Council, 2014 Annual Spring Meeting, May 14, 2014.
112. Rose, J.L., The Polar Vortex and System Reliability, The Energy Authority (TEA), Jacksonville, FL, April 30, 2014.
111. Rose, J.L., Utility and Transco Plans and Transmission Projects to Deal with the Changing Generation Resource Mix, Panel Moderator, Transmission Summit Panel Discussion, March 14, 2014.
110. Rose, J.L., Examining Natural Gas and Power Price Dynamics During the Polar Vortex, APPA, March 10, 2014.
109. Rose, J.L., Polar Vortex – Skating too Close to the Edge, First Friday Club, March 7, 2014.
108. Rose, J.L., New Developments in the California Power Market, Infocast California Energy Summit, San Francisco, CA, December 3, 2013.
107. Rose, J.L., Financial Issues in Determining the Disposition of Fossil Power Plants, Managing the Power Plant Decommissioning, Decontamination, and Demolition Process, November 7, 2013.
106. Rose, J.L, Reality and Impacts of Plant Retirements, Reading Tea Leaves – The Future of America's Installed Power Plants, July 25, 2013.
105. Rose, J.L., Financial issues in Determining the Disposition of Fossil Power Plants, Plant Decommissioning, Decontamination, and Demolition, May 9, 2013.
104. Rose, J.L., Financial Issues in Determining the Disposition of Plant Decommissioning, Decontamination & Demolition Summit, Infocast, May 1, 2013.

103. Rose, J.L., Implications of Current Low Natural Gas Price Environment on Wholesale Power, Edison Electric Institute, May 3, 2012.
102. Rose, J.L., Anticipating the Next Turn in a Gas-Rich Environment, Key Pricing Drivers, and Outlook, Houlihan and Lokey Merchant Energy Conference, April, 24, 2012.
101. Rose, J.L., CREPC/SPSC Natural Gas – Electricity in West Panel, San Diego, April 3, 2012
100. Rose, J.L., EUCI Financing Transmission Expansion, San Diego, CA, March 8-9, 2011.
99. Rose, J.L., Vinson & Elkins Conference, Houston, TX, November 11, 2010.
98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA,
June 29-30, 2010.
97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power Generation in the U.S., DOE-NETL, February 24, 2010.
96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.
95. Rose, J.L., CO_2 Control, "Cap & Trade", & Selected Energy Issues, Multi-Housing Laundry Association, October 26, 2009.
94. Rose, J.L., Financing for the Future – Can We Afford It?, 2009 Bonbright Conference, October 9, 2009.
93. Rose, J.L., EEI's Transmission and Market Design School, Washington, D.C., June 2009.
92. Rose, J.L., ICF's New York City Energy Forum - Market Recovery in Merchant Generation Assets, June 10, 2008.
91. Rose, J.L., Southeastern Electric Exchange – Integrated Resource Planning Task Force Meeting, Carbon Tax Outlook Discussion, February 21-22, 2008.
90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.
89. Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.
88. Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.
87. Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.
86. Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy Infrastructure, September 19, 2005
85. Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.
84. Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.
83. Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.
82. Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?" Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

81. Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.
80. Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.
79. Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.
78. Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.
77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.
76. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.
75. Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York, NY, October 8, 2003.
74. Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.
73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.
72. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.
71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, "Spark Spread Outlook", July 17, 2003.
70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and Economy", June 24, 2003.
69. Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel Management Seminar, Frederick, MD, June 10, 2003.
68. Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for Recovery," March 31, 2003.
67. Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City, VA, March 25, 2003.
66. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.
65. Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY, February 24, 2003.
64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).
63. Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.
62. Rose, J.L., "Assessing U.S. Regional and the Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.

61. Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.
60. Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.
59. Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.
58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.
57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.
56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.
55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.
54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001
53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001
52. Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001
51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001
50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001
49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001
48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.
47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000.
46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000
45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.
44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.
42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.
41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.
40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.
39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.
38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.
37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.
36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.
35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.
34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.
33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.
32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.
31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management Conference, Washington, D.C., March 25, 1999.
30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development Conference, Chicago, Illinois, March 23, 1999.
29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting Conference, Atlanta, Georgia, February 25, 1999
28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.
27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.
25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.
24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.
23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.
22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.
21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.
20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.
19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.
18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.
17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.
16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.
15. Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions," full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.
14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.
13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.
12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.
11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.
10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.
8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.
7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.
6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.
5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.
4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.
3. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.
2. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,
1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

Selected Publications and Presentations

Rose, J.L., "Return of the RTO: Auction Results Portend Recovery," White Paper, June 14, 2014.

Rose, J. L., "The Next Polar Vortex: How Long Will Grid Emergencies and Price Volatility Continue?" Public Utilities Fortnightly, June 2014.

Rose, J.L., "Wind Curtailment, Assessing and Mitigating Risks," White Paper, December 2012.

Rose, J.L. and Henning, B. "Partners in Reliability: Gas and Electricity," PowerNews, September 1, 2012.

Rose, J.L. and Surana, S. "Using Yield Curves and Energy Prices to Forecast Recessions – An Update." World Generation, March/April 2011, V.23 #2.

Rose, J.L. and Surana, S. "Oil Price Increases, Yield Curve Inversion may be Indicators of Economic Recession." Oil and Gas Financial Journal, Volume 7, Issue 6, June 2010

Rose, J.L. and Surana, S. "Forecasting Recessions and Investment Strategies." World-Generation, June/July 2010, V.22, #3.

Rose, J.L., "Should Environmental Restrictions be Eased to Allow for the Construction of More Power Plants? The Costco Connection, April 2001.

Rose, J.L., "Deregulation in the US Generation Sector: A Mid-Course Appraisal", Power Economics, October 2000.

Rose, J. L., "Price Spike Reality: Debunking the Myth of Failed Markets", *Public Utilities Fortnightly,* November 1, 2000.

Rose, J.L., "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes," *Public Utilities Fortnightly,* November 15, 1998.

Rose, J.L., "Why the June Price Spike Was Not a Fluke," *The Electricity Journal*, November 1998.

Rose, J.L., S. Muthiah, and J. Spencer, "Will Wall Street Rescue the Competitive Wholesale Power Market?" *Project Finance International*, May 1998.

Rose, J.L., "Last Summer's "Pure" Capacity Prices – A Harbinger of Things to Come," *Public Utilities Fortnightly,* December 1, 1997.

Rose, J.L., D. Kathan, and J. Spencer "Electricity Deregulation in the New England States," *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, "Financial Engineering in the Power Sector," *The Electricity Journal,* Jan/Feb 1997.

Rose, J.L, S. Muthiah, and M. Fusco, "Is Competition Lacking in Generation? (And Why it Should Not Matter)," *Public Utilities Fortnightly,* January 1, 1997.

Mann, C. and J.L. Rose, "Price Risk Management: Electric Power vs. Natural Gas," *Public Utilities Fortnightly,* February 1996.

Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information," *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.

Employment History

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

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Attachment VI OVEC Plant Parameters [BEGIN CONFIDENTIAL]

Items	Units	Clifty Creek	Kyger Creek
Locational (1,2,3)			
Physical Location		Jefferson, IN	Gallia, OH
Nodal Bus Name/kV		06CLIFTY- 345 kV	06KYGER - 345 kV
Zonal Energy Market		PJM-AEP	PJM-AEP
Future Capacity Market		PJM RTO	PJM RTO
Technology (2)			
Online Year		1955/1956	1955
Configuration		6 subcritical boilers	5 subcritical boilers
Capacity (6)			
Summer Capacity	MW	[redacted]	[redacted]
Winter Capacity	MW	[redacted]	[redacted]
UCAP Capacity	MW	[redacted]	[redacted]
Full Load HR(2)	Btu/kWh	10,763	10,571
Primary Fuel (2)			
Primary Fuel		Bituminous Coal	Bituminous Coal
Fuel Source		NAPP/Illinois Basin	NAPP
Transportation Type		Barge	Barge
Availability			
Scheduled Maintenance(1)	%	11.0	10.0
Forced Outage Rate(6)	%	[redacted]	[redacted]
Availability	%	[redacted]	[redacted]
Operation & Maintenance (5)			
Non-Fuel Variable O&M	2016$/MWh	[redacted]	[redacted]
Emission Control Technology (2,4)			
NO_x		SCR (2003)	SCR (2003)
SO_x		FGD (Jet Bubbling Reactor) (2013)	FGD (Jet Bubbling Reactor) (2012)
Mercury		Yes	No
Emission Rates (1,2)			
CO_2	lbs/MMBtu	205	205
NO_x	lbs/MMBtu	0.13	0.10
SO_2	lbs/MMBtu	0.26	0.22

Source: 1) ICF, 2) SNL Financial, 3) PJM-ISO, 4)www.OVEC.com, 5) OVEC "20yearbillable.xls" spreadsheet, 6)Duke Energy Ohio

[END CONFIDENTIAL]

State Budgets under the Good Neighbor Plan for the 2015 Ozone NAAQS

For the 22 states linked to downwind air quality problems with EGUs covered under this action, EPA issued new or amended Federal Implementation Plans (FIPs) to establish state emissions budgets to reflect additional emission reductions from electric generating units (EGUs) beginning with the 2023 ozone season. To incentivize ongoing operation of identified emission controls to address significant contribution, EPA will also dynamically adjust these states' emission budgets for each ozone season 2026 and thereafter. As such, the table includes emission budgets for each state for each ozone season for 2023 through 2025, and preset budgets for 2026 through 2029. For 2030 and beyond, EPA solely uses the dynamic budget process.

Search:

CSAPR NO_X Ozone Season Group 3 Preset State Emissions Budgets for the 2023 through 2029 Control Periods (tons)

State	Final Emissions Budgets for 2023	Final Emissions Budgets for 2024	Final Emissions Budgets for 2025	Preset Emissions Budgets for 2026	Preset Emissions Budgets for 2027	Preset Emissions Budgets for 2028	Preset Emissions Budgets for 2029
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
Total	**208,119**	**198,014**	**195,259**	**151,329**	**119,663**	**115,193**	**105,201**

CSAPR NO_X Ozone Season Group 3 Preset State Emissions Budgets for the 2023 through 2029 Control Periods (tons)							
State	**Final Emissions Budgets for 2023**	**Final Emissions Budgets for 2024**	**Final Emissions Budgets for 2025**	**Preset Emissions Budgets for 2026**	**Preset Emissions Budgets for 2027**	**Preset Emissions Budgets for 2028**	**Preset Emissions Budgets for 2029**
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416
Total	**208,119**	**198,014**	**195,259**	**151,329**	**119,663**	**115,193**	**105,201**

Note: In the event this final rule becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period will be adjusted under the rule's transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date. The 2023 budget amounts shown in this table do not reflect these possible adjustments. For more information, see the Prorating Emissions Budgets, Assurance Levels, and Unit-Level Allowance Allocations in the Event of an Effective Date After May 1, 2023 (pdf) <https://www.epa.gov/system/files/documents/2023-03/prorating%20emissions%20budgets%20assurance%20levels%20and%20unit-level%20allowance%20allocations.pdf> (200.4 KB, June 8, 2023) factsheet and the discussion of the transitional provisions in Section VI.B.12 of the final rule preamble.

« Return to Good Neighbor Plan for the 2015 Ozone NAAQS <https://epa.gov/cross-state-air-pollution/good-neighbor-plan-2015-ozone-naaqs>

Cross-State Air Pollution Home <https://epa.gov/cross-state-air-pollution>

Good Neighbor Plan

Good Neighbor Plan Results <https://epa.gov/cross-state-air-pollution/good-neighbor-plan-results>

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What Does the Clean Air Act Say? <https://epa.gov/cross-state-air-pollution/what-does-clean-air-act-say-about-cross-state-air-pollution>

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LAST UPDATED ON DECEMBER 18, 2023

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<u>Bottom ash transport water & FGD wastewater compliance dates</u>

<u>Bottom Ash Transport Water</u>
IKEC is proposing to install a high recycle rate boiler slag handling system, which will require the Clifty Creek Station to continue to discharge a portion of that flow as per 40 CFR 423.13(k)(2)(i). As a result, a site-specific volumetric purge has been developed based on the evaluation of an independent engineering firm based on the total wetted volume of the system. Based on the evaluation and the optimization of that system, IKEC is requesting that IDEM approve a purge rate of 221 gpm, which is equivalent to up to 10 percent of the total system volume that would discharge to Outfall 002. A copy of the initial certification statement was included with the permit renewal application as Article 4 of Item IV.

As authorized by the EPA regulations promulgated as part of the Steam Electric Reconsideration Rule on October 13, 2020, 40 CFR 423.13(k)(2)(i) provides:

> The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:
>
> (1) To maintain system water balance when precipitation-related inflows are generated from storm events exceeding a 10-year storm event of 24-hour or longer duration (e.g., 30-day storm event) and cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; or
>
> (2) To maintain system water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible; or
>
> (3) To maintain system water chemistry where installed equipment at the facility is unable to manage pH, corrosive substances, substances or conditions causing scaling, or fine particulates to below levels which impact system operation or maintenance; or
>
> (4) To conduct maintenance not otherwise included in paragraphs (k)(2)(i)(A) (1), (2), or (3) of this section and not exempted from the definition of transport water in §423.11(p), and when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.
>
> The total volume that may be discharged for the above activities shall be reduced or eliminated to the extent achievable using control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice. The total volume of the discharge authorized in this subsection shall be determined on a case-by-case basis by the permitting authority and in no event shall such discharge exceed a 30-day rolling average of ten percent of the primary active wetted bottom ash system volume. The volume of daily discharges used to calculate the 30-day rolling average shall be calculated using measurements from flow monitors.

IDEM reviewed the information submitted with the permit application and has determined that additional information is required from the permittee in order to justify the requested 10% purge. Any request for an authorization to discharge bottom ash purge water should address each of the four above-listed conditions separately. IDEM would expect that the authorized purge amount would be different for each such condition. In the preamble to the regulations, EPA noted that "[b]ased on actual, measured purge rates in EPRI (2016), however, the Agency estimates that actual purge rates necessary on a day-to-day basis may be less than one percent of the system's volume, with higher purges necessary at less frequent intervals due to precipitation and maintenance."

IDEM expects that the day-to-day purge rate would be close to 1% of the system volume, not 10%. It is possible that infrequent precipitation or maintenance events (once a year or so) would necessitate a total purge rate of 10% when those events occur.

However, IDEM believes that additional time to request additional information and review the submitted information is needed to determine what, if any, site-specific purge is necessary at the Clifty Creek Station. Therefore, IDEM is extending the compliance date for the prohibition to discharge bottom ash transport water to December 31, 2023. This date was established based on a current timeline for completion of the high recycle rate boiler slag system submitted by the permittee, as well as consideration of the administrative processing for a potential subsequent permit modification.

Flue Gas Desulfurization (FGD Wastewater)

For FGD wastewater, IDEM established a compliance deadline of November 30, 2022, for the BAT FGD wastewater limitations established in the 2020 Reconsideration Rule (see Section 3.1 above) in the permit modification that was issued November 18, 2021. The facility has requested a new compliance date of December 31, 2025, to meet the final BAT effluent limitations for arsenic, selenium, mercury, and nitrate+nitrite as N.

IDEM has reviewed the effluent data from the current FGD WWTP (Internal Outfall 201) at the Clifty Creek Station since the 2017 permit was issued and believes the facility is currently able to meet the effluent limitations for arsenic in the 2020 Reconsideration Rule. However, the data collected at Internal Outfall 201 shows that the current system is currently unable to meet the final effluent limitations for selenium, mercury, and nitrate+nitrite as N.

Based on the data collected to date that demonstrate compliance with the applicable limitations, IDEM is proposing to retain the November 30, 2022 date for compliance with the final arsenic limitations at Internal Outfall 201.

IDEM notes that the proposed effluent limitations for selenium have changed in the 2020 Reconsideration Rule than those originally included in the final rule published by EPA on November 3, 2015 (Final Rule). For mercury and nitrate+nitrite as N, EPA's selected BAT was changed from chemical precipitation and high residence time reduction biological treatment in the 2015 Final Rule to chemical precipitation and low residence time reduction biological treatment in the 2020 Reconsideration Rule. In addition, the permittee has submitted an updated timeline for construction of the FGD treatment plant. Therefore, IDEM is proposing to change the date of final compliance with the BAT effluent limitations for selenium, mercury, and nitrate+nitrate as N, to December 31, 2025.

Viewpoint: NOx could rise on new regulations

Market: Electricity, Emissions | 12/29/22

Cross-State Air Pollution Rule (CSAPR) seasonal NOx allowances jumped to record highs in 2022 and could climb higher next year, depending on the final form of proposed changes to the program that aim to slash power plant emissions over the next few years.

The season NOx markets shot significantly higher this summer in the wake of a US Environmental Protection Agency (EPA) proposal to expand the CSAPR Group 3 program and set more aggressive emissions limits.

Group 3 NOx, which opened the year at $2,500/short ton, jumped as high as $48,000/st in August. That not only set a record high for the Group 3 program, but it was also considerably higher than any price reached in previous federal NOx trading programs.

Group 2 allowances climbed to $4,500/st in August after starting the year at $275/st.

The EPA plan, released in March, propelled the market higher, as it could soon tighten up what has been an oversupplied market.

The proposal, which also includes new NOx requirements for industrial sources outside of CSAPR, is just the latest shakeup to the seasonal NOx markets. EPA created Group 3 only last year in response to a series of federal court rulings.

In addition to new NOx caps, EPA proposed adding more states to the Group 3 market, including some that have never been covered by CSAPR before, and regularly recalibrating the allowance bank and emissions limits. The 25 states in the expanded Group 3 program would start with a NOx cap of nearly 210,300st in 2023, which could dip to about 129,500st by 2026.

In the eight Group 2 states poised to join Group 3 next year, power plant owners have also had to contend with the costs of joining the more stringent market. They may be able to collectively carry forward only about 18,500 allowances, if EPA requires them to convert Group 2 allowances into Group 3 at a 5.9:1 ratio, as currently planned.

The overall CSAPR program, which also includes annual markets for power plant NOx and SO2 emissions, is designed to help states in the eastern US meet federal air quality standards. The latest proposal is meant to help with the 2015 ozone standards. The ozone season runs from 1 May to 30 September.

The seasonal NOx markets have retreated over the past three months, as power plant owners await the final outcome of the EPA rulemaking. *Argus* last assessed Group 3 NOx at $16,500/st and Group 2 NOx at $2,050/st.

New year, new market

EPA is aiming to finalize the changes in March, just in time for the 2023 ozone season. Whether the final version differs significantly from the original proposal will help determine the direction of the market in 2023.

For example, EPA could modify the final emissions caps or the allowance conversion ratio so that Group 2 power plant owners would be able to carry over more allowances into Group 3.

EPA data suggest that most of the states that will be covered by the expanded Group 3 were near or above their 2023 emissions caps this year. Collectively, ozone season emissions this year from the 25 states that would be included totaled just over 224,000st, which would exceed the 2023 cap by nearly 14,000st, or about 7pc.

Some of that total may include smaller units that will not be subject to CSAPR and does not account for any forthcoming power plant retirements. But with the cap tentatively set to drop by nearly 81,000st, or more than 38pc, from 2023-26, any oversupply in the market now could dry up quickly as compliance demand increases.

In the near term, power-plant owners may also hold on to allowances, as they did this year, for future use or until they have a better understanding of their compliance needs. EPA's proposal only includes suggested budgets for 2025 and 2026. The actual limits will be determined later to account for retirements and other changes to the regulated power plant fleet.

Likely legal challenges could provide some uncertainty to the market once the propsal is finalized. EPA is still awaiting a federal court ruling on its previous CSAPR update.

The market will be closely watching all these program changes, as whatever form EPA's final plan takes will help shape allowance prices in 2023 and beyond.

By Michael Ball

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EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet

EPA's final Good Neighbor Plan for the 2015 ozone NAAQS will improve air quality, saving lives and improving public health in smog-affected communities across the United States. This final rule, which requires emissions reductions from power plants and industrial sources that pollute across state lines, delivers substantial health benefits using proven, cost-effective control technologies and strategies.

Summary of Action

On March 15, 2023, the U.S. Environmental Protection Agency (EPA) issued its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of nitrogen oxides (NO_X) from power plants and industrial facilities. This action will save thousands of lives and result in cleaner air and better health for millions of people living in downwind communities.

The Good Neighbor Plan ensures that 23 states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining EPA's health-based air quality standard for ground-level ozone (or "smog"), known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS), in downwind states.

The final Good Neighbor Plan ensures that emissions reductions will happen as quickly as possible and be aligned with Clean Air Act deadlines for states to achieve the 2015 ozone NAAQS – which vary according to the severity of nonattainment.

- The initial phase of NO_X emissions reductions takes effect as soon as possible prior to the August 3, 2024 attainment date for areas classified as Moderate nonattainment.
- Further emissions reductions phase in at the beginning of the 2026 ozone season to coincide with the August 3, 2027 attainment date for Serious nonattainment areas.

The Final Rule Includes a Combination of Approaches to Reduce Ozone Pollution:

NO_X Allowance Trading Program for Fossil Fuel-Fired Power Plants in 22 States
Beginning in the 2023 ozone season, EPA will include power plants in 22 states in a revised and strengthened Group 3 Cross-State Air Pollution Rule (CSAPR) ozone season trading program. To achieve emissions reductions as soon as possible, EPA is setting the initial control stringency based on the level of reductions achievable through immediately available measures, including consistently operating emissions controls already installed at power plants.

In order to achieve the remaining needed emissions reductions from power plants, the final rule sets emissions budgets that decline over time based on the level of reductions achievable through phased installation of state-of-the-art emissions controls at power plants starting in 2024. Building on the long and successful track record of EPA's CSAPR ozone season trading program, this program will secure significant reductions in ozone-forming pollution while providing power plants operational flexibility they need to continue providing reliable and affordable electric service. The final rule's 2027 budget for power plants reflects a 50% reduction from 2021 ozone season NOx emissions levels.

The final rule includes additional features that promote consistent operation of emissions controls to enhance public health and environmental protection for the affected downwind regions and will also benefit local communities:

- A backstop daily emissions rate in the form of a 3-for-1 allowance surrender for emissions from large coal-fired units that exceed a protective daily NO_X emissions rate. This backstop would take effect in 2024 for units with existing controls and one year after installation for units installing new controls, but no later than 2030;
- Annually recalibrating the size of the emissions allowance bank to maintain strong long-term incentives to reduce NO_X pollution;
- Annually updating emissions budgets starting in 2030 to account for changes in power generation, including new retirements, new units, and changing operation. Updating budgets may start as early as 2026 if the updated budget amount is higher than the state emissions budgets established by the final rule for 2026-2029.

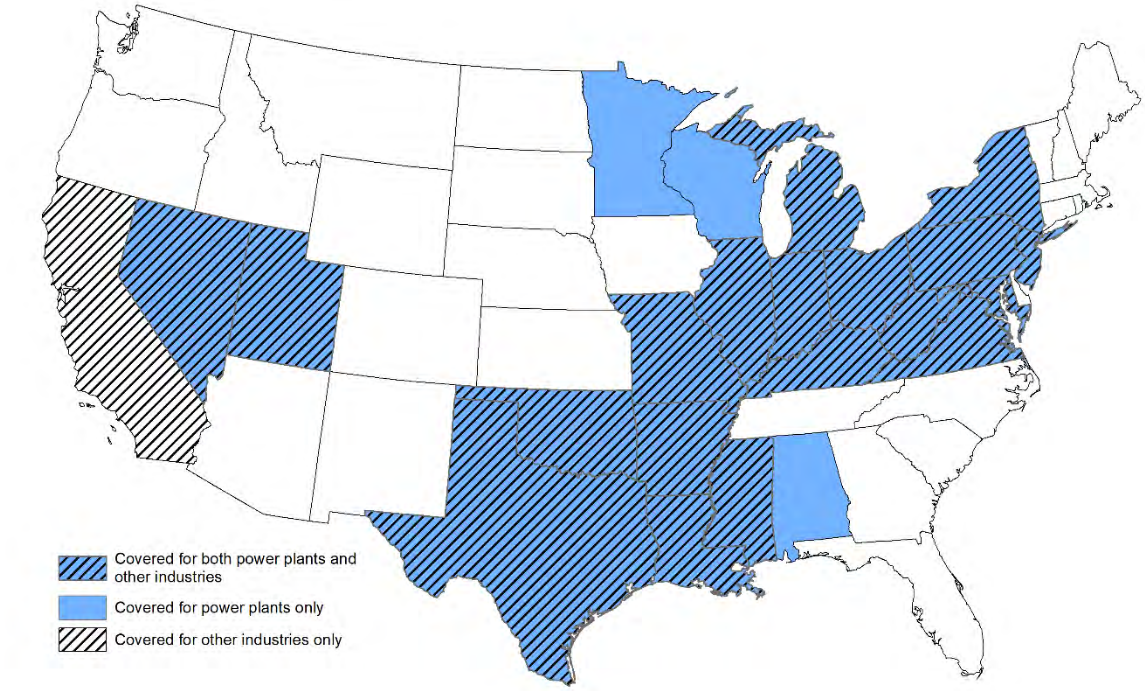
NO_X Emissions Standards for Nine Large Industries in 20 States

Beginning in the 2026 ozone season, EPA is setting enforceable NO_X emissions control requirements for existing <u>and</u> new emissions sources in industries that are estimated to have significant impacts on downwind air quality and the ability to install cost-effective pollution controls. These standards would collectively achieve an approximately 15% reduction in NOx emissions from 2019 ozone season, point source emissions. The reduction in NOx emissions comes from the following types of emissions sources:

  - reciprocating internal combustion engines in **Pipeline Transportation of Natural Gas**;
  - kilns in **Cement and Cement Product Manufacturing**;
  - reheat furnaces in **Iron and Steel Mills and Ferroalloy Manufacturing**;
  - furnaces in **Glass and Glass Product Manufacturing**;
  - boilers in **Iron and Steel Mills and Ferroalloy Manufacturing**, **Metal Ore Mining**, **Basic Chemical Manufacturing**, **Petroleum and Coal Products Manufacturing**, and **Pulp, Paper, and Paperboard Mills**; and
  - combustors and incinerators in **Solid Waste Combustors or Incinerators**.

These industry-specific requirements reflect proven, cost-effective pollution reduction measures that are consistent with standards that sources in downwind states, and throughout the country, have long implemented. With EPA's approval, individual facilities may be eligible for a one year compliance extension. If specific additional criteria are met, EPA may grant additional compliance extensions of up to two more years.

Map of States Covered by the Final Good Neighbor Plan



Since proposal, EPA updated its air quality modeling based on stakeholder input providing improved emissions data and recommendations to improve model performance. EPA's final Good Neighbor Plan relies upon the Agency's most recent air quality modeling data identifying:

- areas expected to have trouble attaining and maintaining the 2015 standards in 2023 and 2026, and
- contributions from upwind states causing downwind ozone problems.

Applying EPA's longstanding, court-affirmed 4-step framework to this information, the final Good Neighbor Plan determines that 23 states must achieve additional reductions in NO_X pollution to fully resolve their outstanding Good Neighbor obligations for the 2015 ozone NAAQS.

EPA's updated modeling analysis for 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico, may be significantly contributing to nonattainment or maintenance in downwind sites. EPA intends to undertake additional assessment of its modeling for these states and will determine if it is necessary to address Good Neighbor obligations for these states in future action(s).

EPA's updated modeling analysis confirms that Delaware is not significantly contributing to downwind ozone air quality problems. The Agency is withdrawing the proposed error correction and the proposed Good Neighbor Plan for Delaware. In addition, EPA is deferring final action on the Agency's proposed Good Neighbor Plans for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis.

EPA's Good Neighbor Plan Would Substantially Reduce Summertime Ozone Levels

EPA estimates that the final Good Neighbor Plan will reduce ozone forming NO_X emissions from the 23 significantly contributing upwind states by approximately 70,000 tons during the 2026 ozone season (May 1 – September 30) compared to a business-as-usual scenario.

About 25,000 tons will come from fossil fuel-fired power plants -- reducing their ozone season NO_X emissions. The additional 45,000 tons of NO_X emissions reductions would come from the other covered industrial sources. These reductions will improve air quality for millions of people across the country.

The final Good Neighbor Plan will also reduce other harmful pollutants from power plants. In 2026 alone, EPA estimates that annual sulfur dioxide emissions will drop by 29,000 tons, annual fine particle emissions by 1,000 tons, and annual carbon dioxide emissions by 16 million metric tons.

Protecting Communities

EPA's final Good Neighbor Plan will reduce ozone across the U.S. with a focus on areas struggling to attain and maintain the 2015 ozone standards.

Program enhancements, including the daily backstop emissions rates for large power plants and program coverage for both existing and future power plant and industrial sources, will achieve air quality benefits in downwind communities that suffer a disproportionate burden from ozone pollution.

Human Health and Environmental Benefits of Reducing Ozone Far Exceed Costs

In the year 2026, the final Good Neighbor Plan will prevent up to 1,300 premature deaths, reduce hospital and emergency room visits for thousands of people with asthma and other respiratory problems, help keep hundreds of thousands of children and adults from missing school and work due to respiratory illness, and decrease asthma symptoms for millions of Americans. For each year from 2027 through 2042, EPA estimates the benefits will be approximately as large as in 2026, although the annual benefits decline slightly over time based on EPA's projection that the health status of the population will improve over this period.

The benefits that EPA could quantify for the final Good Neighbor Plan far outweigh the costs. EPA estimates the benefits in 2026 will be $4.3 billion and could be as much as $15 billion (2016$, 3 percent discount rate). In 2026, the net benefits of this final rule – after accounting for the costs of compliance – are estimated to be $3.7 billion and could be as much as $14 billion (2016$, 3 percent discount rate). EPA estimates that the net present value of this rule over the period from 2023 to 2042, after taking into account compliance costs, is $200 billion (2016$, 3 percent discount rate).

In addition, the emissions reductions projected from the final Good Neighbor Plan will result in a broad range of unquantified benefits, including improving visibility in national and state parks and increasing protection for sensitive ecosystems, coastal waters and estuaries, and forests.

To more fully understand the impacts of this rule, EPA evaluated the effects the Good Neighbor Plan would have on minority populations, low-income populations and/or tribal nations. Our analysis shows that the Good Neighbor Plan will lower ozone and fine particle concentrations in many areas, providing broadly shared benefits for people of color and low-income households.

The cost of achieving these reductions is estimated to be approximately $910 million annually over the period 2023 to 2042 (2016$, 3% discount rate), a fraction of the estimated value of the benefits. As noted above, the final emissions reduction requirements are also based on cost-effective, well-demonstrated pollution control measures that many states have been implementing for years. EPA projects that the final rule will not have a significant impact on small businesses, and that once fully implemented the Good Neighbor Plan will increase the overall costs of electricity production by only slightly more than 1 percent.

The Good Neighbor Plan Preserves Industry's Ability to Deliver Reliable Electricity

The Agency made several adjustments to the proposed emissions reduction requirements for power plants – reflecting input received from grid operators across the country and other stakeholders – to ensure that the power sector can continue to deliver reliable electricity while also achieving cleaner and healthier air. These changes are designed to provide owners and operators of power plants with the operational flexibility and predictability needed to ensure electric system reliability, particularly in the early years of the program. For more detail, see the fact sheet: The Good Neighbor Plan and Reliable Electricity

Background

The Clean Air Act requires states to submit a State Implementation Plan (SIP) that provides for the implementation, maintenance, and enforcement of each primary or secondary NAAQS. Each state must make this new SIP submission within 3 years after promulgation of a new or revised NAAQS. A key Clean Air Act requirement for these SIPs, known as the "Good Neighbor" provision, is that they ensure that sources within the state do not contribute significantly to nonattainment or interfere with maintenance of any NAAQS in other states.

Where EPA finds that a state has not submitted a Good Neighbor SIP, or if the EPA disapproves the SIP submission, within two years, the EPA must issue a Federal Implementation Plan (FIP) to assure downwind states are protected.

EPA is continuing its efforts since the 1990s to implement Good Neighbor requirements, including through rules such as the NO_X SIP Call (1998), the Clean Air Interstate Rule (2005), the Cross-State Air Pollution Rule (CSAPR, 2011), and updates to the CSAPR rule issued in 2016 and 2021. These prior rules successfully addressed less protective ozone NAAQS set in earlier years.

As in its prior interstate transport rules, EPA has employed a longstanding, court-affirmed 4-step framework to identify downwind receptors that are expected to have problems attaining or maintaining the NAAQS, determine which states contribute significantly to these downwind air quality problems, and identify available pollution reduction measures and enforceable requirements necessary to meet the Clean Air Act's Good Neighbor requirements.

More Information

Interested parties can download a copy of the final Good Neighbor Plan from EPA's website at the following address: https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs

Today's action and other background information are also available electronically at https://www.regulations.gov, EPA's electronic public docket and comment system.

For more information about the final action:

- For general questions about the rule, please contact Liz Selbst, Office of Air Quality Planning and Standards, at Selbst.elizabeth@epa.gov.
- For questions about regulatory requirements for power sector sources, please contact Beth Murray, Office of Atmospheric Protection, at Murray.beth@epa.gov.
- For questions about regulatory requirements for industrial sources, please contact Dylan Mataway-Novak, Office of Air Quality Planning and Standards, at Mataway-novak.dylan@epa.gov.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2024.	U-21427

PROOF OF SERVICE

On the date below, an electronic copy of **Public Version of the Direct Testimony and Exhibits of Devi Glick on behalf of Sierra Club and Citizens Utility Board of Michigan (SC-1, SC-3, SC-7 through SC-10, SC-15, and SC-17 through SC-32)** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

TROPOSPHERE LEGAL, PLC
Counsel for SC & CUB

Date: March 4, 2024

Digitally signed by Breanna Thomas
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By: ________________________________

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