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October 16, 2024

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

Via E-File

RE: MPSC Case No. U-21262

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Exhibits of Devi Glick on behalf of Attorney General Dana Nessel, Citizens Utility Board of Michigan, and Sierra Club;
- Exhibits CUB-1 through CUB-20; and
- Proof of Service.

Please note that there is a Public and Confidential Version of Ms. Glick's testimony and Exhibit CUB-7C is confidential. These documents will be filed under seal and served to only those with a Nondisclosure Certificate on file. Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Christopher Bzdock
Date: 2024.10.16 16:52:19 -04'00'

Chistopher Bzdok
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CC: Parties to Case No. U-21262

STATE OF MICHIGAN
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, 2023.	Case No. U-21262

DIRECT TESTIMONY OF DEVI GLICK ON BEHALF OF ATTORNEY GENERAL DANA NESSEL, CITIZENS UTILITY BOARD OF MICHIGAN AND SIERRA CLUB

PUBLIC VERSION

October 16, 2024

TABLE OF CONTENTS

DIRECT TESTIMONY OF D. GLICK ON BEHALF OF AG, CUB AND SC
CASE NO. U-21262

LIST OF EXHIBITS

LIST OF TABLES

LIST OF FIGURES

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 in over 60 different proceedings before state utility regulators in more than 20 states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as widely used optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 12 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit CUB-1.

Q On whose behalf are you testifying in this case?

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

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

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-21261, I&M's 2023 PSCR Plan docket; Case No, U-20805, I&M's 2021 reconciliation docket; Case No. U-21427, I&M's 2024 PSCR Plan docket.

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

A In my testimony for this proceeding, I evaluate three subjects: First, I evaluate the Company's request to recover costs paid for power from the Ohio Valley Electric Corporation ("OVEC") in 2023. Second, I evaluate I&M's request to recover costs paid to AEP Generation ("AEG") in 2023 for power generated by AEG's portion of Rockport Unit 1. Third, I review the fuel and power purchase costs for I&M's owned share of Rockport Unit 1 that it plans to pass on to customers for 2023.

Q How is your testimony structured?

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

In Section 3, I discuss how I&M customers paid unreasonable prices, significantly above market, to OVEC for power under the Inter-Company Power Agreement ("ICPA") in 2023. I present several different metrics that can be used to value the services provided under the ICPA. I also outline my recommendations to the Commission to disallow recovery of ICPA costs above market value.

In Section 4, I discuss how I&M customers paid unreasonable prices in 2023, far above market, for the portion of Rockport Unit 1's power that I&M purchased from AEG through a power purchase agreement ("PPA") called the Unit Power Agreement ("UPA"). I explain how these costs are also representative of the costs that I&M passes through to ratepayers for the portion of the Rockport Unit 1 that it owns. I explain how the Commission, in I&M's PSCR plan case for 2018, directed the Company to take actions to address the costs of the

AEG contract, but I&M failed to take any such actions. I also outline my recommendations to the Commission to disallow recovery of UPA costs above market value.

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, as well as discovery from other proceedings where applicable. 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 State of the Market reports for PJM.

II. Findings and Recommendations

Q Please summarize your findings.

A My primary findings are:

Table 1. OVEC and Rockport revenues and charges for 2023 ($2023)

	Cost / revenue category	ICPA (OVEC)		UPA (AEG portion of Rockport 1)	
		I&M share ($Million)	Michigan share ($Million)	I&M share ($Million)	Michigan share ($Million)
A	Energy revenue	$ 23.8	$ 3.6	$ 22.7	$ 3.4
B	Capacity revenue	$ 2.5	$ 0.4	$ 9.7	$ 1.5
C	Ancillary revenue	-	-	$ 0.2	$0.0
D	**Total Value (A+B+C)**	**$ 26.3**	**$ 4.0**	**$ 32.6**	**$ 4.9**
E	Energy charge	$ 27.1	$ 4.1	$ 28.3	$ 4.3
F	Demand charge	$ 32.4	$ 4.9	$ 66.7	$ 10.1
G	Taxes	$ 1.2	$ 0.2	$ 6.5	$ 0.9
H	**Total cost (E+F)**	**$ 59.5**	**$ 9.0**	**$ 94.9**	**$ 14.3**
I	Total cost net of taxes (G-F)	$ 58.3	$ 8.8	$ 88.8	$ 13.4
J	**Energy losses (A-E)**	**$ (3.2)**	**$ (0.5)**	**$ (5.6)**	**$ (0.8)**
K	**Total losses (D-H)**	**$ (33.2)**	**$ (5.0)**	**$ (62.3)**	**$ (9.4)**
L	**Excess cost based on weighted average benchmark**	**$ (18.0)**	**$ (2.7)**	**($51.1)**	**($7.7)**

1. I&M has been purchasing power from OVEC, an affiliate company, at above-market value and passing those costs on to customers. Over the course of 2023, the ICPA cost I&M customers $33.2 million more than the cost of equivalent energy and capacity purchased from the market, and more than $18.0 million more than the cost of long-term power supply benchmarks.

2. I&M paid its affiliate AEG for a portion of AEG's share of Rockport Unit 1 at a cost that was far in excess of market value. Over the course of 2023, the UPA cost I&M customers $62.3 million more than the cost of equivalent energy and capacity purchased from the market, and more than $51.1 million more than the cost of other long-term power supply benchmarks.

3. The OVEC and Rockport coal plants both lost money on an energy basis in 2023. At the OVEC plants, I&M's share of energy market losses was $3.2 million. At Rockport Unit 1, I&M share was $5.6 million for the portion it purchases from AEG and $5.6 million for the portion it owns. This means that the OVEC and Rockport plants are not passing the lowest bar of economic operations in covering their fuel and variable operating costs with their energy market revenues. This also means that ratepayers would have been better off in 2023 if the plants had not

operated — even taking into account that I&M would still have to pay the demand charges regardless.

Q Please summarize your recommendations.

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

1. The Commission should disallow in this proceeding $5.0 million, which is Michigan's jurisdictional share of the total $33.2 million in excess compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services). This represents the difference between what I&M charged customers for OVEC power, and the equivalent price that I&M would pay to procure the energy and capacity from the PJM market in 2023.
2. Alternatively, based on a weighted average of benchmarks from the Cambell Unit 2 and Belle River power agreements, with taxes removed, the Commission should disallow $2.7 million in excess costs. This represents the Michigan jurisdictional share of the total $18.0 million in excess compensation that I&M paid for OVEC service under the ICPA.
3. The Commission should disallow in this proceeding $9.4 million, which is Michigan's jurisdictional share of the total $62.3 million in excess compensation that I&M paid AEG for power from Rockport services under the UPA (relative to the market value of energy and capacity in 2023).
4. Alternatively, based on a weighted average of benchmarks from the Cambell Unit 2 and Belle River power agreements, with taxes removed, the Commission should disallow $7.7 million in excess costs. This represents the Michigan jurisdictional share of the total $51.1 million in excess compensation that I&M paid for OVEC service under the ICPA.

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 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 the utilities through a long-term contract called the Inter-Company Power Agreement.[1] Together, the utilities are responsible for the fixed and variable costs of OVEC. In turn, OVEC bills the utilities a variable, demand, and transmission charge. The Michigan Public Service Commission has found that OVEC is an affiliate of I&M.[2]

Q How often were the OVEC plants operated in 2023?

A The OVEC plants at Clifty Creek and Kyger Creek were operated at a 43 percent and 48 percent capacity factor respectively in 2023.[3] These are relatively high utilization levels for older coal units with high operating costs. As discussed below, the OVEC plants also incurred high energy market losses in 2023. Utilities can minimize or avoid energy market losses through prudent economic commitment practices, which result in lower utilization rates for plants with high operating costs relative to newer more efficient power plants. When plants such as these incur high energy market losses, that is an indication that the plants were being operated without regard for economic fundamentals (i.e., they were likely committed into the market with a "must-run" status, rather than allowing economically based commitment decisions by the system operator, PJM). The plants' high

[1] Ex CUB-2, Ohio Valley Electric Corporation, Annual Report, 2023 (p. 1); Ex CUB-2, Inter Company Power Agreement (ICPA), as amended.

[2] Case No. U-20529, Commission Order dated May 13, 2021, p. 17.

[3] United State Environmental Protection Agency (EPA) Clean Air Markets Program Data (CAMDP).

utilization and high energy market losses call into question the prudence of OVEC's operational practices.

Q What portion of OVEC is I&M responsible for?

A I&M's share of the ICPA with OVEC is 7.85 percent.[4] 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 share of 165.9 MW for January-May and 166 MW July-December.[5] The cost of the ICPA is passed through to I&M ratepayers as a direct cost.

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

A No. The Commission has found that the ICPA was not approved by the Commission, nor were the 2004 and 2010 amendments, which resulted in extending the ICPA through 2040.[6] The Clifty Creek and Kyger Creek Plants will each be 85 years old by the time the ICPA expires in 2040.[7]

[4] Ex CUB-2, Ohio Valley Electric Corporation, Annual Report, 2023, p. 1.

[5] Ex CUB-4, I&M Response to SCCUB Request 1-06.

[6] Case No. U-20529, Commission Order dated May 13, 2021, p. 13.

[7] Ex CUB-2, Ohio Valley Electric Corporation, Annual Report, 2023, p. 1.

B. <u>I&M pays above-market prices for the power it purchases from OVEC and passes the excess costs on to its customers</u>

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

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

For units owned or leased by I&M, the fuel costs associated with running the units are forecasted in PSCR dockets, recovered via the PSCR factor, and then reconciled in reconciliation dockets such as this one. All other operational costs are the subject of separate proceedings such as rate cases. For power purchased under PPAs, PSCR dockets serve to forecast the entire cost—rather than just the fuel costs—to operate the units generating the power. This cost is recovered directly from customers via the PSCR factor and then reconciled in reconciliation dockets such as this one. Since 2018, I&M's total PSCR costs have increased around 15 percent in real dollars.[8]

[8] Calculated based on Exhibit IM-3, p. 1 of 4; Case No. U-21053 Exhibit IM-4, p. 1 of 4; Case No. U-20805 Exhibit IM-4, p. 1 of 4; Case No. U-20530 Exhibit IM-4, p. 1 of 4; Case No. U-20224 Exhibit IM-3, p. 1 of 4; Case No. U-20204 Exhibit IM-3, p. 1 of 4.

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

A If I&M can purchase the energy and capacity that it needs from the PJM market 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 Is the ICPA delivering value to I&M ratepayers?

A No. In 2023, OVEC lost money on an energy basis. I&M was billed $27,052,885 or $35.97/MWh[9] for its energy and received only $23,839,081 or $31.69/MWh[10] in energy market revenues. I&M admitted this itself in direct testimony submitted in this docket.[11] This resulted in energy losses of more than $3.2 million. This means that the OVEC plants are not passing the lowest bar of economic operations in covering their fuel and variable operating costs with their energy market revenues. This also means that ratepayers would have been better off in 2023 if the OVEC plants had not operated—even taking into account that I&M would still have to pay the demand charges regardless.

I&M stated that the plants' poor performances were due to a decline in PJM energy prices, not an increase in ICPA energy costs.[12] But ICPA energy charges for the past five years show an increasing trend. Specifically, I&M's energy costs jumped substantially in 2022 and remained at similar levels in 2023. In 2022, the increased costs were masked by the

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[9] Calculated from I&M Response to SCCUB Request 1-01, U21262 AR 1 Attachment 4, OVEC Available Power Statements. See Ex CUB-6.

[10] Ex CUB-5, I&M Response to SCCUB Request 1-05, Attachment 1.xlsx, OVEC Billing and Energy Revenue Information.

[11] Direct Testimony of Jason Stegall, p. 32.

[12] *Id*.

abnormally high energy market revenues. But with energy market prices back to baseline levels, energy market revenue is no longer sufficient to cover the rising ICPA energy charges.

Q Is the ICPA delivering value to I&M ratepayers based on the total value of the services it provides?

A No. On a total value basis — that is taking into account both energy and capacity — the OVEC plants are costing substantially more than the value they provide. As a Sponsoring Company,[13] I&M was billed $79.11/MWh[14] under the ICPA for energy and demand charges[15] from OVEC. The power was only worth $34.95/MWh based on its value if I&M were to sell it into the PJM energy and capacity markets.[16]

Figure 1 below shows the $/MWh difference by month between the cost and value of OVEC's power. The shaded area in the middle shows the $/MWh cost premium that I&M customers are paying each month. This shows that in each month of 2023, I&M ratepayers were paying significantly more for OVEC services than the equivalent market value of the services.

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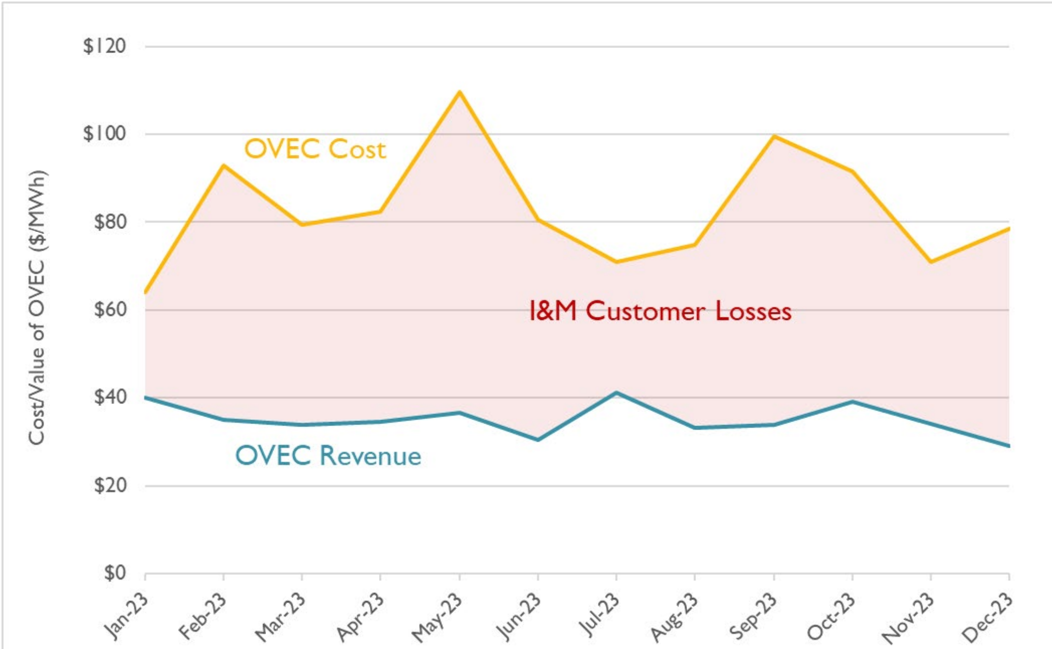
[13] The owners of OVEC and their utility-company affiliates are considered Sponsoring Companies. Sponsoring Companies are each either a shareholder in the Company or an affiliate of a Shareholder in the Company, with the exception of Energy Harbor Corp.

[14] Calculated from I&M Response to SCCUB Request 1-01, U21262 AR 1 Attachment 4. See Ex CUB-6.

[15] Ex CUB-5, I&M Response to SCCUB Request 1-05, Attachment 1.xlsx.

[16] Ex CUB-5, I&M Response to SCCUB Request 1-05, Attachment 1; Ex CUB-20, excerpt of 2023 State of the Market Report for PJM (p. 333).

Figure 1. All-in OVEC cost / value for energy and capacity (2023)



Sources: Ex CUB-6, I&M Response to SCCUB Request 1-01 U-21262 AR 1 Attachment 4; Ex CUB-5, I&M Response to SCCUB 1-05, Attachment 1; Ex CUB-20, 2023 State of the Market Report for PJM (p.333).

The total difference between what OVEC was charging I&M and the value of the power works out to a net loss of $33.2 million in 2023 that I&M customers are being asked to pay while receiving no additional value. The Michigan jurisdictional share of the total losses is $5.0 million.

Q How do you calculate the cost and value to ratepayers of OVEC?

A I&M provided the monthly billing from OVEC for 2023 which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[17] Based on this billing data, OVEC charged I&M $60,784,471 for 752,148 MWh of electricity, for an average cost of $80.81 per MWh. To isolate just the energy and demand charges, I removed

[17] Ex CUB-5, I&M Response to SCCUB Request 1-05, Attachment 1.

the transmission and PJM expenses and fees and ancillary charges. This results in a total of $59,504,866 for an average cost of $79.11/MWh.

The Company also provided energy revenue data by month which showed that the Company earned $23,839,081 in energy market revenues from the sale of OVEC power into the PJM market.[18] That works out to an average energy value of $31.69/MWh. Using the installed capacity values for 2023 (165.9 MW in January-May, and 166 MW June-December),[19] I estimated a capacity value based on the weighted average value that I&M's share of OVEC capacity would receive in the PJM Base Residual Auction ("BRA"). This was $49.95/MW-day for the first half of 2023 and $34.21/MW-day for the second half of the year.[20] This works out to an average capacity value of only $3.26/MWh. The combined energy and capacity value of OVEC's power in the PJM market at $34.95/MWh[21] is well below the cost OVEC is charging I&M for power under the ICPA.

Q How do the costs and value of the ICPA in 2023 compare to the cost and value of the power in recent years?

A The cost for power under the ICPA has been significantly above market value since at least 2017, with the only exception being 2022 when the war in Ukraine drove gas prices, and therefore market energy prices, up to record high levels. As shown in Table 2 below, net

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[18] *Id*.

[19] I&M Response to SCCUB Request 1-06.

[20] Ex CUB-20, 2023 State of the Market Report for PJM (p. 333).

[21] Ex CUB-5, I&M Response to SCCUB 1-05; Ex CUB-20, 2023 State of the Market Report for PJM (p. 333).

losses under the ICPA are 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 I&M's latest PSCR plan filing in Case U-21427 shows (and my testimony in that docket discusses) the cost of OVEC power is projected to jump significantly going forward.[22]

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	60,784,471	$26,290,619	$80.81	$34.97	($34,493,852)

Source: Case U-21427, Direct Testimony of Devi Glick, p. 23.
Note: 2023 values have been updated to reflect a "one time billing adjustment that OVEC applied in July to Non-PJM Sponsors based on OVEC Unit Performance during December 2022 PJM Performance Assessment Interval event.[23]

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

A No. OVEC power is expensive relative to alternatives even when using the 2025/2026 high capacity value. Specifically, capacity prices cleared at $269.92/MW-day for 2025/2026, up from $28.92/MW-day in the last capacity auction.[24] But that is still far below the OVEC demand charge, which works out to an average of $535.76/MW-day. As I will discuss

[22] Case No. U-21427, Direct Testimony of Devi Glick.

[23] Ex CUB-6, I&M Response to SCCUB Request 1-01, U-21262 AR 1 Attachment 4.

[24] Ex CUB-13, Excerpt of PJM 2025/2026 Base Residual Auction Report, July 30, 2024, p. 8.

further below, even if OVEC's capacity was valued at the 2025/2026 clearing price for all of 2023, OVEC's power cost would still exceed its market value. This is due to not only its high demand charge but also its high energy charges, which as discussed above, exceeded its energy market revenues.

Q What do you conclude with respect to the ICPA and the services that I&M ratepayers receive from the contract?

A Based on I&M's own data I find that under the ICPA, in 2023 alone, billed energy and capacity charges cost I&M customers $33.2 million more than the market price for the same amount of energy and capacity. This means that ratepayers would have been better off in 2023 if I&M did not purchase power from OVEC and instead purchased energy and capacity from the market.

C. <u>A reasonable price to pay for power under the ICPA should be measured based on the cost billed for similar services or the cost of replacement resources</u>

Q Has I&M provided any reasonable comparators for the value of the energy and capacity provided by OVEC?

A In prior dockets I&M refused to provide any comparators for the value of the power it received under the ICPA. In the 2021 PSCR Plan docket, the Commission ordered I&M to "provide a justification of its costs under the ICPA in its reconciliation of its 2021 PSCR plan"[25] and indicated that it will "look to comparisons with other long-term supply options

[25] Case No. U-20804, Commission Order dated Nov. 18, 2021, p. 26.

as informative as to whether this particular contract adheres to the requirements of the Code of Conduct."[26]

In the present docket, I&M proposed to compare the cost of OVEC to two of its own renewable resources that were the product of all-source Request for Proposals in Michigan issued in 2022—the Mayapple solar facility with an LCOE of $[[[redacted]]]/MWh and the Lake Trout solar facility with an LCOE of $[[[redacted]]]/MWh.[27] The Company also proposed the transfer price published by the Commission in Docket U-15800.[28] But none of these present reasonable comparators for the services under the ICPA.

Q Explain why the transfer price is not a reasonable comparator for the Commission to use in evaluating the value of OVEC's power.

A The transfer price is fundamentally not a market cost comparator. It is based on the levelized cost of power from a new natural gas plant that begins operating in 2023. The levelized cost represents an average lifetime cost, calculated as the net present value of the cost to build, maintain, and operate a plant over the entire life of the PPA. This is problematic for several reasons.

First, Staff assumes the lifetime is 20 years, which is a relatively short lifetime over which to spread the full capital investment of a new fossil resource. Industry-standard

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[26] *Id.,* pp. 18-19.

[27] Direct Testimony of Company Witness Jason Stegall, p. 18.

[28] *Id.*, pp. 21-22.

assumptions for new gas resources are generally 30 years, as I&M itself assumed in its most recent integrated resource plan ("IRP").[29]

Second, the average cost of power over a plant lifetime does nothing to reflect the cost of power in a single specific year where market factors may be driving higher or lower relative costs and utilization in a given year.

Finally, the Commission established in several prior dockets that the transfer price is only to be used for planning purposes, such as the calculation of the renewable energy plan docket (REP) surcharge.[30]

Q Explain why the renewable PPAs presented by I&M Witness Stegall are not reasonable comparators for the Commission to use in evaluating the value of OVEC's power.

A The renewable energy contracts are for a product that is different in nature from that provided by the coal plants. The PPAs were acquired through an IRP and contracted in part to meet a renewable portfolio standard. The projects were also not producing power during the reconciliation period of 2023. For these reasons, the Commission has rejected use of the Mayapple and Lake Trout PPAs in its final orders in multiple dockets, including U-20805 and U-21261.

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[29] 2021 I&M Integrated Resource Planning Report. January 31, 2022, p. 95. Available at https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/2021IMIRPReportRevised.pdf.

[30] Case No. U-15806 and Case No. U-17302.

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

A There are several reasonable long-term supply comparisons we can use to evaluate whether the costs charged under the ICPA are reasonable and compliant with the MPSC Code of Conduct. These include: (1) The costs billed or paid by other entities for *similar services* provided under short- and long-term power supply agreements; (2) the cost of replacement capacity resources as represented by Cost of New Entry (CONE); (3) the gross avoidable cost of existing generation for a typical PJM coal plant; (4) the cost of replacement capacity and energy resources as represented by responses to requests for proposals (RFP) and other Company information; (5) and the PJM short-term capacity and energy market. Table 3 below summarizes the alternative benchmarks discussed in this section on a $/MWh basis and calculates the total excess costs incurred under the ICPA relative to each benchmark.

Q Have you made any updates to your benchmark analysis from prior dockets?

A Yes, based on the Commission Order in Case No. U-21053,[31] I removed Component C of the Demand charge of the ICPA, which covers total expenses for taxes not included in Component A, B, or D (Accounts 408, 409, 411), in calculating the excess costs incurred relative to the MPPA arrangements. I removed this component in the benchmark analysis because the Commission found that "it is reasonable to remove the effect of taxation from

[31] Case No. U-21053, Final Order dated Sept. 26, 2024.

the ICPA since the MPPA is a tax-exempt entity whereas the company is not."[32] The taxes were not removed for any other benchmark comparisons.

Table 3. OVEC cost benchmarks for 2023 ($2023)

	Capacity cost ($/MWh)	Energy cost ($/MWh)	Total cost ($/MWh)	Excess costs based on benchmark ($Million)
OVEC PSCR cost[1]	$43.15	$35.97	$79.11	NA
Cost of similar services				
In-year transfer price[2]	n/a	n/a	$62.64	$11.18
MPPA billing from Consumers Energy for Campbell Unit 3[3]	$11.08	$35.78	$46.85	$23.05
MPPA billing from DTE for Belle River[3]	$11.35	$43.73	$55.07	$16.87
Contract for Pleasants coal plant[4]	[[[redacted]]]	[[[redacted]]]	[[[redacted]]]	[[[redacted]]]
Contract for Montpelier and Tait gas plants[4]	[[[redacted]]]	[[[redacted]]]	[[[redacted]]]	[[[redacted]]]
Value of CONE & PJM BRA				
CONE – combined-cycle plant coming online in 2026[5]	$32.68	$27.93	$60.51	$13.99
Gross avoidable cost for existing generation - Coal[6]	$8.12	$55.07	$63.19	$11.98
Gross avoidable cost for existing generation - CC[6]	$7.87	$31.19	$39.06	$30.13
Gross avoidable cost for existing generation – CT[6]	$22.46	$39.45	$61.90	$12.95
PJM base residual auction (BRA)[8]	$3.28	$35.97	$39.24	$29.99

Sources: (1) I&M Response to SCCUB Request 1-01 U-21262 AR 1 Att. 4; (2) Ex CUB-8, U-15800 Docket Filing, 2023 MPSC Staff Transfer Price Schedule; (3) Ex CUB-12, MPPA Financial Statement for 2023, Ex p. 11, statement p. 7;(4) I&M Response to SCCUB Request 1-08, Confidential Attachment 1; (5) Ex CUB-9, Brattle PJM CONE Study, 2022; (6) Ex CUB-10, Gross Avoidable Costs for Existing Generation, Prepared for PJM by Brattle Group. January 9, 2023; (7) Ex CUB-20,2023 State of the Market Report (p. 333).

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[32] *Id.*, pp. 11-12.

Q How does the cost of power under the ICPA compare to the billed costs for other similar long-term PPAs?

A The cost of power under the ICPA is much higher than the cost paid for power under several similar long-term PPAs in the region. I reviewed Michigan Public Power Agency (MPPA) Financial Statement[33] for annual expenses and revenues billed from DTE for Belle River and from Consumers for J.H. Campbell 3. I calculated the average cost billed for power charged for each unit. I find that in 2023, Consumers Energy billed MPPA an average of \$46.85/MWh for power purchased from J.H. Campbell 3 and DTE billed MPPA an average of \$55.07/MWh for the power purchased from Belle River. These charges covered the fuel, and operations and maintenance ("O&M") expenses, administration and generation costs, and depreciation expenses from similar thermal resources and provided both energy and capacity to MPPA. Note that both transmission and RTO costs were excluded, as they are not included in the base energy and demand charges of the ICPA. This results in excess costs of \$23.05 million and \$16.87 million respectively for Campbell Unit 3 and Belle River relative to the value of the ICPA.

Q How does the cost of power under the ICPA compare to the cost of any recent bilateral capacity contracts that I&M signed?

A I&M has two short-term bilateral contracts for capacity purchases for the period June 1, 2024–May 21, 2025. While these cover a timeframe beyond the PSCR period of 2023, they are nonetheless useful in understanding the cost of other resources available in the market at this point. Specifically, the contract with the Pleasants coal plant cost \$[[[redacted]]]/MW-

[33] Ex CUB-12, MPPA Financial Statement, December 2023.

day and the contract with Montpelier and Tait gas plants cost $[[[redacted]]]/MW-day. This is much lower than the price of capacity from OVEC which was $546/MW-Day in 2023. Because these contracts have no energy component, I valued energy at the same cost as OVEC energy. Using this assumption, the total value of the contracts worked out to $[[[redacted]]]/ MWh and $[[[redacted]]]/MWh, respectively.

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

A CONE is a conservative measure of 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.[34] To find the capacity cost in $/MWh, I the first multiplied the $/MW-Day CONE values by the MW of a representative combined-cycle gas plant and then multiplied that by 365 days in a year. I then found the total annual MWh for a new combined-cycle plant based on the average annual capacity factor of 64 percent,[35] and the representative plant size from the CONE report.[36] I divided the total cost by total MWh to get a capacity cost per MWh.

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[34] Ex CUB-9, Excerpt of Brattle PJM CONE 2026/2027 Study, April 2022, p. *vii*, Table ES-1.

[35] U.S. Energy Information Administration. 2023. "Natural gas combined-cycle power plants increased utilization with improved technology." *Today in Energy*. Available at https://www.eia.gov/todayinenergy/detail.php?id=60984.

[36] Ex CUB-9, Excerpt of Brattle PJM CONE 2026/2027 Study, April 2022, p. 21, Table 4.

For the energy cost, I calculated total annual MWh for a representative new combined-cycle plant based on Brattle's heat rate and plant size assumptions,[37] 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.[38] 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 $60.51/MWh based on CONE of a new combined-cycle unit. This conservative 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 2021 capacity auction?

A CONE is much higher than the cleared capacity value (auction price) from PJM's 2024/2025 BRA because there remains surplus capacity available for participation in the PJM capacity market. This auction produced a capacity price of $28.92/MW-day for year 2024/2025 which is the lowest it has been in the past 10 auctions.[39] As discussed above, capacity prices cleared at $269.92/MWh-day in the more recent auction for 2025/2026.[40] But even at this level, it is still far below the OVEC demand charge, which works out to an

[37] Ibid, Table 4.

[38] Case No. U-21427, I&M Response to Sierra Club Request 1-5, SC 1-5 Attachment 1.

[39] Ex CUB-9, Brattle PJM CONE 2026/2027 Study, April 2022, Table 4.

[40] Ex CUB-13, PJM 2025/2026 Base Residual Auction Report, July 30, 2024.

average of $535.76/MWh-day. Further, high capacity market prices are not expected to be sustained; instead, they send a signal to the market to build more capacity.

Q 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.[41] PJM calculates an updated gross avoidable cost rate (ACR) every four years and uses it to determine default offer thresholds for the capacity market.[42] 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 the Federal Energy Regulatory Commission ("FERC") found the rates to be unrealistically high and switched to the ACR.[43] The 2023 report contains ACRs for nuclear, coal, natural gas combined-cycle and combustion-turbine units, oil and gas steam turbined units, onshore wind, and solar PV.[44] I present the ACR for a coal plant, combined-cycle unit, and combustion-turbine unit here to show the $/MW-day cost of a representative existing coal plant and combustion-turbine plant.

[41] Ex CUB-10, Excerpt of *Gross Avoidable Costs for Existing Generation*, Prepared for PJM by Brattle Group. January 9, 2023, p. iii.

[42] *Ibid.*

[43] *Id.*, p. 6.

[44] *Id.,* p. v.

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 high cost by any reasonable measure. I have presented a number of reasonable alternatives in this section for current fossil resources contracted under similar PPAs, for new fossil resources, and for PJM market prices that demonstrate this point. Yet I&M customers are paying as much as $30 million per year in excess of the cost of these long-term supply comparisons.

D. I&M is free to continue purchasing power from OVEC as a matter of business, but if the costs are not prudently incurred, I&M is not entitled to recover the costs from Michigan ratepayers

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

A Yes. In Case U-20529, the Commission stated in its final order that "it will expect to see evidence that the Company has taken steps to minimize the cost of [power], including efforts to renegotiate contracts…"[45] In the subsequent PSCR case, Case U-20804, the Commission reiterated this directive for I&M to seek to renegotiate the contracts. The Commission also issued a Section 7 warning, notifying I&M in this docket that "the Commission is unlikely to permit the utility to recover these uneconomic costs from its customers in rates, rate schedules, or PSCR factors established in the future without good faith efforts to manage existing contracts such as meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers."[46] In Case No. U-21052, the Commission stated in its final order that I&M should "uphold its obligations to assess its existing contracts as market conditions or other factors change over time and to pursue amendments or new contractual agreements that may include taking meaningful steps to renegotiate provisions of the ICPA."[47] The Commission issued a Section 7 warning in that case.[48]

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

A Only minimally. I&M President and COO Steven F. Baker sent a letter to OVEC in January of 2022 outlining the Commission orders listed above and "requesting that OVEC commence renegotiation discussions with I&M in a manner to reduce costs for I&M." OVEC responded that I&M would need to obtain consent from every other sponsoring

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[45] Case No. U-20529, Commission Order dated May 13, 2021, p. 18.

[46] Commission Order dated Nov. 18, 2021, in Case U-20804, p. 20.

[47] Commission Order dated June 22, 2023, in Case U-21052, p. 20.

[48] *Id.,* p. 21.

Company to modify the ICPA. OVEC also indicated that that it would need FERC approval, regulatory approval by state utility commissions, and advance consent from counterparties to OVEC's debt arrangements to modify the contract.[49]

I&M indicated that in September 2023 Mr. Baker sent another letter to OVEC to engage other Sponsoring Companies in renegotiation discussions, and "take all possible steps to reduce costs under the ICPA." And subsequently in January 2024 the Company sent another letter to the OVEC Board of Directors indicating its intention to sell the portion of the ICPA associated with the Michigan jurisdiction. I&M indicated that it received no correspondence from the Board or any Sponsoring Companies.[50]

There is no indication that I&M took any operational steps to reduce how much the plants were self-scheduled, or otherwise influence the day-to-day operations of the OVEC plants.

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

A No. I&M has made clear in multiple dockets that it does not have the authority to unilaterally change how the OVEC units are operated and therefore has limited power over plant operations. Specifically, Company Witness Stegall says that while the Company can provide input into the procedures OVEC follows to operate the units, "I&M is one vote of

[49] Case U-21052, I&M Response to Sierra Club 7-3, Attachment 1.

[50] Direct Testimony of Jason Stegall, p. 15.

the many needed to effectuate management or operational decisions because I&M cannot unilaterally force OVEC to do anything."[51]

While this might be true, it does not mean that I&M is totally powerless, and it does not give I&M the right to pass on to ratepayers any and all costs incurred to operate and manage the OVEC plants. The Commission agreed with this sentiment in a prior order. Specifically, in the final order in Case U-20530, the 2020 Reconciliation docket, the Commission stated "I&M, of course, remains free to continue to make whatever business decisions it wishes in terms of continuing to participate in the ICPA. What it cannot do is continue to recover the costs of any unreasonable and imprudent decisions from its customers."[52]

Q What are your recommendations to the Commission regarding the OVEC units?

A I am recommending that the Commission once again disallow costs incurred by I&M to operate the OVEC plants that are passed on to Michigan ratepayers. Specifically, the Commission should disallow in this proceeding $5.0 million, which is Michigan's jurisdictional share of the total $33.2 million in excess compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services). This represents the difference between what I&M charged customers for OVEC power, and the equivalent price that I&M would pay to procure the energy and capacity from the PJM market in 2023.

[51] Case No. U-20805, Direct Testimony of Witness Stegall, p. 5.

[52] Case No. U-20530, Commission Order dated Feb. 2, 2023, pp. 12-13.

Alternatively, using MPPA's contract for Campbell Unit 3 and Belle River as a benchmark, with each weighted based on generation, I find that ICPA power exceeds the cost of benchmarks by $23.92/MWh (Table 4). Multiplying the $/MWh cost difference between the ICPA and the Cambelle and Belle River benchmarks in 2003 by the ICPA MWh in 2023, I find that I&M paid around $18 million in excess costs for the ICPA in 2023. Of that, $2.7 million is Michigan's share.

Table 4. ICPA excess costs relative to benchmarks in 2023 ($2023)

	MWh	Contract cost $	$/MWh
Weighted average benchmarks	1,321,012	$70,787,304	$53.59
Campbell Unit 3	239,156	$11,205,302	$46.85
Belle River	1,081,856	$59,582,002	$55.07
ICPA	752,148	$58,294,566	$77.50
Excess cost	752,148	$17,990,216	**$23.92**
Michigan share		**$2,712,899**	

Source: Ex CUB-6, I&M Response to SCCUB Request 1-01 U-21262 AR 1 Att. 4; Ex CUB-12, MPPA Financial Statement for 2023.

IV. I&M ALSO PAID EXCESS AND ABOVE-MARKET COSTS TO AEG FOR POWER FROM ROCKPORT IN 2023

A. Overview of Rockport Unit 1

Q Provide an overview of the Rockport Generating Station.

A The Rockport Generating Station is a two-unit coal-fired power station located in Spencer County, Indiana. I&M operates the plant. Unit 1 has a nameplate capacity of 1,320 MW and is 50 percent owned by I&M and 50 percent owned by AEG. Unit 2 was previously owned by non-affiliated parties and leased back to I&M and AEG. This lease expired in December 2022. Since that time, Rockport Unit 2 has been operated as a merchant facility and all related costs are excluded from this reconciliation docket.[53]

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

Q How often was Rockport used in 2021?

A The Rockport units operated at only a 12 percent capacity factor in 2023.[54]

[53] Direct Testimony of Denzil L. Welsh, p. 9.

[54] Ex CUB-6, I&M Response to SCCUB Request 1-01, U-21262 AR 1 Attachment 5.

Q What portion of Rockport Unit 1's costs is I&M responsible for and how are those costs passed on to its ratepayers?

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

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

For the 50 percent share of Rockport Unit 1 that AEG owns, I&M pays for the power through the UPA. [55] 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.

[55] Ex CUB-14, Unit Power Agreement.

B. <u>I&M paid excessive and above-market costs for power from Rockport to its affiliate AEG in 2023</u>

Q What did I&M pay under the UPA to purchase Rockport Unit 1 power from AEG in 2023?

A I&M purchased 704,318 MWh of Rockport power from AEG in 2023 for a total cost of $94,942,593.[56] That comes out to $134.80/MWh.[57] This is substantially less generation than I&M purchased under the UPA in prior years because of the expiration of the lease with Unit 2 and the lower capacity factor.

Q Under what agreement did I&M make these purchases?

A I&M purchased power from Rockport Unit 1 under the UPA with AEG dated March 31, 1982, and an amendment dated May 8, 1989.[58]

Q Are I&M and AEG affiliates?

A Yes. Both AEG and I&M are subsidiaries of AEP. I am advised by counsel that Rule 8(4) of the MPSC Code of Conduct's affiliate price cap would apply to the AEG purchases just as it does to the OVEC purchases. Another affiliate relationship can be found in the fact that I&M operates the plant that produces the power that it buys from AEG. I am advised

[56] I&M only provided energy and capacity values. This does not include transmission charges and PJM expenses and fees.

[57] Ex CUB-6, I&M Response to SCCUB Request 1-01, U-21262 AR 1 Attachment 5.

[58] Ex CUB-14, Unit Power Agreement.

by counsel that in Case Nos. U-20530 and U-20805, the Commission held that the UPA is subject to Rule 8(4) of the Code of Conduct.[59]

Q What does the UPA require I&M to pay AEG?

A I&M is required to pay AEG an energy charge and a demand charge to receive the energy and capacity allotted to I&M from AEG's owned and leased shares of Rockport.[60] The demand charge includes a return on common equity ("ROE") to AEG.

Q What is the ROE that I&M pays to AEG?

A The ROE is set at 12.16 percent.[61]

Q Did the Commission approve the UPA or the amendment?

A Only partially. The Commission originally approved the inclusion of the capacity charges related to the purchase of Rockport Unit 2 capacity from AEG in a 1991 order.[62] But I&M has not identified any Commission Order approving charges related to the AEG share of Rockport Unit 1. In addition, I&M has not identified any Commission Order adjudicating the UPA's compliance with the MPSC Code of Conduct.

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[59] Case No. U-20530, Commission Order dated Feb. 2, 2023, p. 15.

[60] Ex CUB-14, Unit Power Agreement, Section 1.3.

[61] Ex CUB-15, Excerpt of FERC UPA application, ER19-717-000.

[62] Ex CUB-16, Case No. U-20530, I&M Response to AG Request 2-29.

Q Has the Commission issued any direction to I&M in recent years regarding the purchases from AEG under the UPA?

A Yes. In 2019, the Commission issued an order in Case U-18404,[63] in response to a recommendation by the Attorney General regarding the ROE awarded to AEG. This order reiterated that I&M has an obligation to examine existing contracts as market conditions change and make good-faith attempts to negotiate and amend these contracts. Further, the Commission stated that I&M was expected to "demonstrate to this Commission, in the PSCR reconciliation proceeding and future plan cases, that its wholesale purchases from affiliates are just and reasonable under current market conditions… and that the utility is taking appropriate actions to minimize costs to ratepayers pursuant to Act 304."[64]

Q Has I&M attempted to compare the cost of the UPA to market prices or any other benchmarks in order to determine whether it complies with the affiliate price cap in the MPSC Code of Conduct?

A No. I&M's response in discovery pointed only to benchmarks for the OVEC power. There was no mention of benchmark analysis for the UPA.[65]

Q How does the cost of the Rockport power purchased under the UPA compare to the market value of the power?

[63] Case No. U-18404, Commission Order dated June 7, 2019.

[64] *Id.*, pp. 7–8.

[65] Ex CUB-19, I&M Response to SCCUB Request 1-44.

A In 2023, Rockport Unit 1 lost money on an energy basis. For the 50 percent share it purchased from AEG, I&M was billed $28,270,942 or $40.14/MWh for its energy[66] and received only $22,863,844 or $32.46/MWh in energy market revenues.[67] I&M admitted this itself in direct testimony submitted in this docket.[68] This resulted in energy losses of more than $5.6 million for the 50 percent share from AEG, and $11.2 million total in energy market losses across all of Rockport Unit 1. This means that Rockport Unit 1, as with the OVEC plants, is not passing the lowest bar of economic operations in covering its fuel and variable operating costs with its energy market revenues. This also means that ratepayers would have been better off in 2023 if Rockport Unit 1 had not operated—even taking into account that I&M would still have to pay AEG the demand charges to AEG regardless of how much the unit operated.

On a total value basis—that is taking into account both energy and capacity of AEG's share of Rockport Unit 1—the picture is once again even worse. I&M was billed a total of $134.80/MWh[69] under the UPA for energy and demand charges[70] from AEG's 658.8 MW[71] portion of Rockport Unit 1. The power was only worth $46.28/MWh based on its

[66] Ex CUB-6, I&M Response to SCCUB Request 1-01, U-21262 AR 1, Attachment 5.

[67] Ex CUB-18, I&M Response to SCCUB Request 1-41, Attachment 1.

[68] Direct Testimony of Jason Stegall, p. 38. The energy revenues and energy charges in table 2 differ slightly from those provided in discovery requests 1-01 and 1-41.

[69] Ex CUB-6, I&M Response to SCCUB Request 1-01, U21262 AR 1 Attachment 5.

[70] Ex CUB-6, I&M Response to SCCUB Request 1-01, U21262 AR 1 Attachment 5.

[71] Ex CUB-17, I&M Response to SCCUB 1-10.

value if I&M were to sell it into the PJM energy and capacity markets.[72] This means that I&M customers are paying an estimated $88.52/MWh premium for Rockport Unit 1's energy and capacity services over the equivalent value of the energy and capacity in the PJM market. This works out to a total $62.35 million premium for AEG's portion of Rockport Unit 1's services allocated to I&M based on the UPA. Approximately $8.69 million of this will be passed on to Michigan customers in this reconciliation docket through the UPA and an equal amount through excess fuel costs recovered in this docket, as well as fixed costs recover through rate case dockets, for the portion of Rockport Unit 1 owned by I&M.

Q How did you calculate the cost of Rockport power from the AEG contract?

A I&M provided its bills from AEG for its share of Rockport Unit 1 for each month in 2023.[73] I calculated the energy charges for each month as the sum of fuel, purchased power, taxes, and fuel from the prior month's adjustment for both units. The remaining charges in the total bill reflect non-variable costs; I classified these as part of a demand charge.

Q How does the cost of the Rockport power from the AEG contract compare to the other long-term supply benchmarks that you discussed earlier in your testimony?

A It exceeds all of them. In fact, it is more than twice as much as any of the other supply options I benchmarked. I compared the price of power I&M paid for AEG's share of Rockport Unit 1 under the UPA to the benchmarks I provided in Section 3 for MPPA's

[72] Ex CUB-18, I&M Response to SCCUB Request 1-41, Attachment 1.; Ex CUB-20, 2023 State of the Market Report for PJM (p. 333).

[73] Ex CUB-6, I&M Response to SCCUB Request 1-01, U-21262 AR 1 Attachment 5.

purchase of power from Campbell Units 3 and Belle River (Table 5). I find that I&M paid more than $51.1 million in excess costs under the UPA; the Michigan share of excess costs was $7.7 million.

Table 5. UPA excess costs relative to benchmarks in 2023 ($2023)

	MWh	Contract cost $	$/MWh
Weighted average benchmarks	1,321,012	$70,787,304	$53.59
Campbell Unit 3	239,156	$11,205,302	$46.85
Belle River	1,081,856	$59,582,002	$55.07
UPA	704,318	$88,791,861	$126.07
Excess cost	704,318	$51,050,497	$72.48
Michigan share		$7,698,341	

Source: Ex CUB-6, I&M Response to SCCUB Request 1-01 U-21262 AR 1 Att. 5; Ex CUB-12, MPPA Financial Statement for 2023.

The Commission should continue to compare the cost of the Rockport power from the AEG contract to the cost of other long-term supply resources.

Q What are your recommendations to the Commission regarding I&M's payment to AEG under the UPA?

A The Commission should disallow in this proceeding $9.40 million, which is Michigan's jurisdictional share of the total $62.3 million in excess compensation that I&M paid AEG for power from Rockport services under the UPA (relative to the market value of the services). Of this total, $846,188 represents the Michigan jurisdictional share of the total $5.6 million in excess energy costs. The remaining $8.55 million is the Michigan jurisdictional share of excess demand charges. This represents the difference between what I&M charged customers for Rockport power purchased from AEG power, and the equivalent price that I&M would pay to procure the energy, capacity, and ancillary services from the PJM market in 2023. The Commission should also disallow an additional $846,188 for the excess fuel cost that I&M incurred from the portion of Rockport Unit 1 that it owns.

Q How do the costs incurred under the UPA relate to the costs I&M incurs to operate the portion of Rockport that I&M owns?

A As I&M itself stated, "The costs incurred by the Company under the UPA represent a pro rata share of the same Rockport-related costs incurred by the Company and recovered through base rates."[74] In other words, the PPA costs AEG is charging to I&M under the UPA represent the all-in cost (inclusive of fuel, O&M, capital costs, and other costs) to operate the portion of Rockport owned by AEG. These identical costs are passed on to I&M ratepayers for the portion of Rockport that it owns; it's just harder for ratepayers to see the full cost because the costs are distributed across multiple dockets (notably fuel costs in the current PSCR docket and the remaining costs in rate case dockets) and broken down into many different categories for cost recovery. But this means that I&M customers are also paying $134.80/MWh for the portion of Rockport owned by I&M.

Q Does this conclude your testimony?

A Yes.

[74] Direct Testimony of Jason Stegall, p. 34.

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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*

PUBLICATIONS

Kwok, S., D. Glick, R. Anderson, T. Gyalmo. 2023. *Review of Southwestern Public Service Company 2023 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Kwok, S., J. Smith, D. Glick. 2023. *Review of Cleco Power's 2021 IRP Report.* Synapse Energy Economics for Sierra Club.

Addleton, I., D. Glick, R. Wilson. 2021. *Georgia Power's Uneconomic Coal Practices Cost Customers Millions*. Synapse Energy Economics for Sierra Club.

Glick, D., P. Eash-Gates, J. Hall, A. Takasugi. 2021. *A Clean Energy Future for MidAmerican and Iowa.* Synapse Energy Economics for Sierra Club, Iowa Environmental Council, and the Environmental Law and Policy Center.

Glick, D., S. Kwok. 2021 *Review of Southwestern Public Service Company's 2021 IRP and Tolk Analysis.* Synapse Energy Economics for Sierra Club.

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

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

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

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

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

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

Glick, D., J. Frost, B. Biewald. 2020. *The Benefits of an All-Source RFP in Duke Energy Indiana's 2021 IRP Process.* Synapse Energy Economics for Energy Matters Community Coalition.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

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

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

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

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

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

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

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

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

Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

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

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

TESTIMONY

State of Vermont Public Utility Commission (Case No. 24-2945-PET): Direct testimony of Devi Glick in Petition of VT Real Estate Holdings 2 LLC ("Fair Haven Solar") for a Certificate of Public Good, pursuant to 30 V.S.A. § 248, authorizing the installation and operation of a 20 MW solar electric generation facility off Airport Road in Fair Haven, Vermont to be known as the "Fair Haven Solar Project". On behalf of VT Real Estate Holdings 2 LLC. September 17, 2024

Public Service Commission of South Carolina (Docket No. 2024-203-E): Direct Testimony of Devi Glick in Application of Kingstree East 230 for a certificate of environmental compatibility and public convenience and necessity for the construction and operation of a 249 MW AC solar and battery facility in Williamsburg County, South Carolina Pursuant to S.C.Code Ann. § 58-33-10 et. Seq., and request to proceed with initial construction work, S.C. Code Ann. § 58-33-110(7). On behalf of Kingstree East 230 LLC. August 9, 2024.

Indiana Utility Regulatory Commission (Cause No. 46038): Direct Testimony of Devi Glick in Petition of Duke Energy Indiana, LLC Pursuant to Indiana code §§ 8-1-2-42.7 and 8-1-2-61, for authority to modify its rate and changes. On behalf of Citizens Action Coalition of Indiana, Inc. July 11, 2024.

State of Vermont Public Utility Commission (Case No. 23-1447-PET): Rebuttal testimony of Devi Glick in the Petition of VT Real Estate Holdings 1 LLC for a Certificate of Public Good, pursuant to 30 V.S.A. § 248, for a 20 MW ground-mounted solar array in Shaftsbury, Vermont. On behalf of VT Real Estate Holdings 1 LLC ("Shaftsbury Solar"). Revised June 27, 2024.

State of Vermont Public Utility Commission (Case No. 23-1447-PET): Direct testimony of Devi Glick in the Petition of VT Real Estate Holdings 1 LLC ("Shaftsbury Solar") for a Certificate of Public Good, pursuant to 30 V.S.A. § 248, authorizing the installation and operation of a 20 MW solar electric generation facility off Holy Smoke Road in Shaftsbury, Vermont to be known as the "Shaftsbury Solar Project". On behalf of VT Real Estate Holdings 1 LLC ("Shaftsbury Solar"). Revised June 27, 2024.

Iowa Utilities Board (RPU-2023-002): Supplemental Testimony of Devi Glick in re: Interstate Power and Light Company, Proposed Rate Increase. On behalf of Environmental Intervenors. June 21, 2024.

Florida Public Service Commission (Docket No. 20240026-EI): Direct testimony of Devi Glick in petition for rate increase by Tampa Electric Company. On behalf of Sierra Club. June 6, 2024.

Iowa Utilities Board (RPU-2023-0002): Surrebuttal Testimony of Devi Glick in re: Interstate Power and Light Company, Proposed Rate Increase. On behalf of Environmental Intervenors. June 3, 2024.

Iowa Utilities Board (RPU-2023-0002): Direct Testimony of Devi Glick in re: Interstate Power and Light Company, Proposed Rate Increase. On behalf of Environmental Intervenors. April 16, 2024.

Michigan Public Service Commission (Case No. U-21051): 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-21050) for the 12 months ended December 31, 2022. On behalf of Michigan Environmental Council. March 8, 2024.

Michigan Public Service Commission (Case No. U-21427): 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 (2024). On behalf of Sierra Club and Citizens Utility Board of Michigan. March 4, 2024.

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 October 2024

ANNUAL REPORT — 2023

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

Ohio Valley Electric Corporation

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

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

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

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

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

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

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

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

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

Some of the Common Stock issued in the name of:

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

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

A Message from the President

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

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

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

SAFETY

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

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

CULTURE

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

RELIABILITY

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

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

ENERGY SALES

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

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

POWER COSTS

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

2022 ENERGY SALES OUTLOOK

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

COST CONTROL INITIATIVES

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

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

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

ENVIRONMENTAL COMPLIANCE

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

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

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

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

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

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

BOARD OF DIRECTORS AND OFFICERS CHANGES

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

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

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

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

Brian D. Sherrick
OVEC-IKEC President

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2023 AND 2022

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

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2023 AND 2022

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

See notes to consolidated financial statements.

(Concluded)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

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

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

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

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

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

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

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

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. RELATED-PARTY TRANSACTIONS

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

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

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

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

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

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

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

3. COAL SUPPLY

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

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

4. ELECTRIC PLANT

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

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

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

5. BORROWING ARRANGEMENTS AND NOTES

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

6. LONG-TERM DEBT

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

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

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

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

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

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

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

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

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

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

7. INCOME TAXES

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

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

Components of the income tax provision were as follows:

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

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

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

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

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

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

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

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

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

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

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

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

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

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

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

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

Investment strategies include:

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

The target asset allocation for each portfolio is as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Postemployment Benefits—The Companies follow the accounting guidance in ASC Topic 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 34% and 66% split between OVEC and IKEC, respectively, as of December 31, 2023, and approximately a 31% and 69% split between OVEC and IKEC, respectively, as of December 31, 2022. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $8,808,588 and $10,567,071 at December 31, 2023 and 2022, respectively.

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

9. ENVIRONMENTAL MATTERS

Air Regulations

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

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

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

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

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

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

CCR Rule

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

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

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

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

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

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

NAAQS Compliance for SO_2

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

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

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

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

NAAQS compliance for Particulate Matter ("PM")

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

Steam Electric Effluent Limitations Guidelines

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

The rule was intended to require power plants to modify the way they handle a number of wastewater processes. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the USEPA issued an administrative stay on the ELG rule. In June 2017, the USEPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The USEPA revised the rule redefining what constitutes "best available technology" for these two wastewater discharges and issued an updated final rule in the *Federal Register* on October 13, 2020. Based on the original rule and revisions captured in the 2020 update, the following impacts to each wastewater discharge are expected:

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

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

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

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

316(b) Compliance

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

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

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

Utility Greenhouse Gas Regulations

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

10. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2023 and 2022, are as follows:

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

11. LEASES

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

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

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

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

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

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

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

Supplemental cash flow information related to leases was as follows:

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

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

Future maturities of finance lease liabilities are as follows:

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

12. COMMITMENTS AND CONTINGENCIES

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

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of Ohio Valley Electric Corporation:

Opinion

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

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

Basis for Opinion

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

Responsibilities of Management for the Financial Statements

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

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

In performing an audit in accordance with GAAS, we:

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

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

/s/ DELOITTE & TOUCHE LLP

April 19, 2024

OVEC PERFORMANCE—A 5-YEAR COMPARISON

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

DIRECTORS

Ohio Valley Electric Corporation

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

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

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

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

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

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

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

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

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

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

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

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

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

Indiana-Kentucky Electric Corporation

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

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

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

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

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

Officers—OVEC AND IKEC

BRIAN D. SHERRICK
President

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

KASSANDRA K. MARTIN
Secretary and Treasurer

JULIE SHERWOOD
Assistant Secretary and
Assistant Treasurer

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

Execution Copy

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

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

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

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

WITNESSETH THAT:

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

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 ______________________

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

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active 12026116.4

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

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By [signature]
Its VICE PRESIDENT

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By [signature]
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

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

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By [illegible signature]
Its Vice President

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By Anthony J. Ahern
Its President & CEO

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active.12026116 4

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By 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 ____________________

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	**ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.**
By ______________ Its ______________	By ______________ Its ______________
APPALACHIAN POWER COMPANY	**BUCKEYE POWER GENERATING, LLC**
By ______________ Its ______________	By ______________ Its ______________
COLUMBUS SOUTHERN POWER COMPANY	**THE DAYTON POWER AND LIGHT COMPANY**
By ______________ Its ______________	By ______________ Its ______________
DUKE ENERGY OHIO, INC.	**FIRSTENERGY GENERATION CORP.**
By ______________ Its ______________	By Gary R Leidich Its President
INDIANA MICHIGAN POWER COMPANY	**KENTUCKY UTILITIES COMPANY**
By ______________ Its ______________	By ______________ Its ______________

030860-0015-02023-Active.12026116.4

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By [signature]
Its Sr Vice President

030860-0015-02023-Active 12026116.4

LOUISVILLE GAS AND ELECTRIC COMPANY

By [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

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur
Its President

APPROVED AS TO FORM:

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

SCHEDULE 10.01(c)

Allegheny Energy Supply Company, L.L.C.

and

Monongahela Power Company

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

SCHEDULE 10.01(c)

Appalachian Power Company

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

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

SCHEDULE 10.01(c)

Buckeye Power Generating, LLC

None

SCHEDULE 10.01(c)

Columbus Southern Power Company

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

SCHEDULE 10.01(c)

The Dayton Power and Light Company

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

SCHEDULE 10.01(c)

Duke Energy Ohio, Inc.

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

SCHEDULE 10.01(c)

FirstEnergy Generation Corp.

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

SCHEDULE 10.01(c)

Indiana Michigan Power Company

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

Filing with the Indiana Utility Regulatory Commission

SCHEDULE 10.01(c)

Kentucky Utilities Company

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

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

SCHEDULE 10.01(c)

Louisville Gas and Electric Company

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

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

SCHEDULE 10.01(c)

Ohio Power Company

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

SCHEDULE 10.01(c)

Peninsula Generation Cooperative

None

SCHEDULE 10.01(c)

Southern Indiana Gas and Electric Company

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

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD AND SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-21262

DATA REQUEST NO. 1-06- SCCUB

Request

Provide the ICAP for I&M's share of OVEC in 2023.

Response

The Company's share of OVEC provided 165.9 MW of Installed Capacity (ICAP) for the PJM Planning Year spanning from June 1, 2022 - May 31, 2023. The Company's share produced 166.0 MW of ICAP for the PJM Planning Year spanning from June 1, 2023 - May 31, 2024.

Preparer

Stegall

Indiana Michigan Power Company
OVEC Billing and Energy Revenue Information
Calendar Year 2023

	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/Fees	Total Bill	Energy Revenues	Net Energy Margin
Jan 2023	$2,318,994	$2,086,361	$104,800	$16,109	$4,526,265	$2,580,086	$261,092
Feb	$1,492,508	$2,392,717	$93,557	$15,726	$3,994,509	$1,271,851	-$220,657
Mar	$2,375,667	$2,568,966	$101,823	-$5,090	$5,041,366	$1,891,236	-$484,431
Apr	$2,363,792	$2,917,880	$102,731	-$10,205	$5,374,197	$2,003,128	-$360,664
May	$1,612,841	$2,840,725	$92,616	$81	$4,546,262	$1,261,089	-$351,751
Jun	$2,327,616	$2,886,688	$102,724	$1,661	$5,318,688	$1,831,865	-$495,751
Jul	$2,567,309	$2,454,507	$105,240	$42,812	$5,169,868	$2,793,380	$226,071
Aug	$2,471,768	$2,651,258	$104,378	$3,313	$5,230,717	$2,149,608	-$322,159
Sep	$1,801,552	$2,752,362	$95,007	$13,349	$4,662,270	$1,413,519	-$388,033
Oct	$2,108,742	$3,052,797	$99,316	$7,079	$5,267,933	$2,080,808	-$27,934
Nov	$2,502,937	$2,663,109	$106,099	$10,182	$5,282,327	$2,372,107	-$130,830
Dec	$3,109,159	$3,184,612	$109,000	$8,264	$6,411,035	$2,190,404	-$918,755

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD AND SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-21262

DATA REQUEST NO. 1-01-SCCUB

Request

Produce, on an ongoing basis, all responses to Staff audit requests.

Response

Please see the following Responses and associated attachments:

SCCUB 1-1 Attachment 1: Response to AR 1

SCCUB 1-1 Attachment 2: Response to AR 2

SCCUB 1-1 Attachment 3: Response to AR 3

SCCUB 1-1 Attachment 4: Response to AR 4

SCCUB 1-1 Attachment 5: Response to AR 5

SCCUB 1-1 Attachment 6: Response to AR 6

SCCUB 1-1 Attachment 7: Response to AR 7

Preparer
Welsh

January 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 9,046,711.44	$ 0.00	$ 9,046,711.44	$ 9,194,334.00	$ (147,622.56)
Buckeye	10,378,636.13	0.00	10,378,636.13	10,547,984.00	(169,347.87)
Cincinnati	5,189,316.59	0.00	5,189,316.59	5,273,991.00	(84,674.41)
Columbus	2,560,045.78	0.00	2,560,045.78	2,601,827.00	(41,781.22)
Dayton	2,825,285.61	0.00	2,825,285.61	2,871,391.00	(46,105.39)
Energy Harbor	2,796,489.54	0.00	2,796,489.54	2,842,115.00	(45,625.46)
Indiana	4,526,264.69	0.00	4,526,264.69	4,600,116.00	(73,851.31)
Kentucky	1,538,240.94	0.00	1,538,240.94	1,564,111.00	(25,870.06)
Louisville	3,464,187.33	0.00	3,464,187.33	3,522,446.00	(58,258.67)
Monongahela	2,018,073.69	0.00	2,018,073.69	2,051,009.00	(32,935.31)
Ohio Power	8,931,398.53	0.00	8,931,398.53	9,077,135.00	(145,736.47)
Peninsula	3,834,330.24	0.00	3,834,330.24	3,896,896.00	(62,565.76)
So. Indiana	952,153.07	0.00	952,153.07	967,483.00	(15,329.93)
PJM Sponsors	(421,735.26)	0.00	(421,735.26)	(410,838.00)	(10,897.26)
Total	$ 57,639,398.32	$ 0.00	$ 57,639,398.32	$ 58,600,000.00	$ (960,601.68)

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 2/20/2023

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 26,923,861.52	
Fuel Oil Consumed	665,409.26	
Other Fixed Fuel Related Costs*	(376,402.91)	
Total Account 501 (Fuel)		$ 27,212,867.87
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		2,328,274.90
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 29,541,142.77

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge $ 29,541,142.77

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	$ **29,541,142.77**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	141,137,000	0.1568998	$ 4,634,999.39
Buckeye	161,916,000	0.1799995	5,317,390.93
Cincinnati	80,958,000	0.0899997	2,658,693.99
Columbus	39,939,000	0.0443995	1,311,611.97
Dayton	44,077,000	0.0489997	1,447,507.13
Energy Harbor	43,628,000	0.0485005	1,432,760.20
Indiana	70,614,000	0.0785005	2,318,994.48
Kentucky	25,591,000	0.0284491	840,418.92
Louisville	57,633,000	0.0640697	1,892,692.15
Monongahela	31,484,000	0.0350003	1,033,948.86
Ohio Power	139,338,000	0.1548999	4,575,920.06
Peninsula	59,819,000	0.0664998	1,964,480.09
So. Indiana	16,244,000	0.0180582	533,459.86
PJM Sponsors	(12,842,000)	-0.0142762	(421,735.26)
Total	899,536,000	1.0000000	$ 29,541,142.77

Available Power Energy Summary

Available Energy Billed			899,536,000	kWh
Average Available Energy Cost	29,541,142.77 / 899,536,000	=	32.840	mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 27,589,270.78	
Available Energy Billed	899,536,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)	30.671	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	16,758,062.24
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		6,840,131.60
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		1,078,755.50
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	26,577,849.34

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026		$	2,148,838.81
2006-A Extended Notes, 6.40%, due June 15, 2040			128,453.76
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026			1,525,260.67
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040			98,456.67
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026			316,256.17
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026			657,911.13
2008-B Extended Notes, 6.91% due June 15, 2040			90,556.33
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026			648,687.43
2008-C Extended Notes, 6.91% due June 15, 2040			92,129.67
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022			2,500,000.00
	Total Debt Amortization		8,206,550.64

Capital Lease Expense

Capital Lease Expense	$	69,562.35

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,727,546.82
428	Amortization of Debt Discount and Expense		142,970.75
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		499,166.80
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,369,684.37

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,112,264.88
TOTAL COMPONENT A	$	16,758,062.24

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	837,402.71
502	Steam Expenses		860,835.26
505	Electric Expenses		298,793.70
506	Miscellaneous Steam Power Expenses		227,056.56
507	Rents		0.00
510	Maintenance of Supervision and Engineering		661,199.00
511	Maintenance of Structures		277,024.88
512	Maintenance of Boiler Plant		2,835,589.43
513	Maintenance of Electric Plant		(948,739.55)
514	Maintenance of Miscellaneous Steam Plant		60,510.56
556	System Control and Load Dispatching		499.52
557	Other Expenses		0.00
	Total Production Expenses	$	5,110,172.07
Transmission Expenses			
560	Operation Supervision and Engineering	$	41,151.19
561	Load Dispatching		55,084.13
562	Station Expenses		112,069.44
563	Overhead Line Expenses		909.64
566	Miscellaneous Transmission Expenses		47,171.16
567	Rents		(2.14)
568	Maintenance of Supervision and Engineering		(55.36)
569	Maintenance of Structures		19,301.84
570	Maintenance of Station Equipment		76,134.32
571	Maintenance of Overhead Lines		(21,216.85)
573	Maintenance of Miscellaneous Transmission Plant		1,078.96
	Total Transmission Expenses	$	331,626.33
Administrative and General Expenses			
920	Administrative and General Salaries	$	412,271.75
921	Office Supplies and Expenses		84,009.78
922	Administrative and General Expenses Transferred - Credit		(18,876.02)
923	Outside Services Employed		430,662.17
924	Property Insurance		354,674.01
925	Injuries and Damages		261,510.50
926	Employee Pensions and Benefits		1,181,725.86
928	Regulatory Commission Expenses		0.00
929	Duplicate Charges - Credit		(2,560.86)
930	Miscellaneous General Expenses		28,917.75
931	Rents		(778.08)
935	Maintenance of General Plant		1,807.54
	Total Administrative and General Expenses	$	2,733,364.40
	Total Operation and Maintenance Allocated to Component B	$	8,175,162.80
Deduct Transmission Charge (Account 566.1)			(1,335,031.20)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	6,840,131.60

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 26,577,849.34**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 4,170,064.56
Buckeye	18.00	4,784,012.88
Cincinnati	9.00	2,392,006.44
Columbus	4.44	1,180,056.51
Dayton	4.90	1,302,314.62
Energy Harbor	4.85	1,289,025.69
Indiana	7.85	2,086,361.17
Kentucky	2.50	664,446.24
Louisville	5.63	1,496,332.92
Monongahela	3.50	930,224.73
Ohio Power	15.49	4,116,908.86
Peninsula	6.65	1,767,426.98
So. Indiana	1.50	398,667.74
Total	100.00	$ 26,577,849.34

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$ 1,335,031.20**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 209,466.39
Buckeye	18.00	240,305.62
Cincinnati	9.00	120,152.81
Columbus	4.44	59,275.39
Dayton	4.90	65,416.53
Energy Harbor	4.85	64,749.01
Indiana	7.85	104,799.95
Kentucky	2.50	33,375.78
Louisville	5.63	75,162.26
Monongahela	3.50	46,726.09
Ohio Power	15.49	206,796.33
Peninsula	6.65	88,779.57
So. Indiana	1.50	20,025.47
Total	100.00	$ 1,335,031.20

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**604,244.97**
Energy Cost of PJM External Power		**(421,735.26)**
Net PJM External Charge/(Credit)	$	**182,509.71**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	32,181.10
Buckeye	19.92		36,926.70
Cincinnati	9.96		18,463.35
Columbus	4.91		9,101.91
Dayton	5.42		10,047.33
Energy Harbor	5.37		9,954.64
Indiana	8.69		16,109.09
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		7,174.01
Ohio Power	17.14		31,773.28
Peninsula	7.36		13,643.60
So. Indiana	0.00		-
Total	100.00	$	185,375.01

February 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 7,983,905.65	$ 0.00	$ 7,983,905.65	$ 7,452,749.00	$ 531,156.65
Buckeye	9,159,356.81	0.00	9,159,356.81	8,549,986.00	609,370.81
Cincinnati	4,579,678.41	0.00	4,579,678.41	4,274,995.00	304,683.41
Columbus	2,259,298.60	0.00	2,259,298.60	2,108,995.00	150,303.60
Dayton	2,493,371.13	0.00	2,493,371.13	2,327,489.00	165,882.13
Energy Harbor	2,467,960.92	0.00	2,467,960.92	2,303,765.00	164,195.92
Indiana	3,994,508.98	0.00	3,994,508.98	3,728,755.00	265,753.98
Kentucky	1,307,197.17	0.00	1,307,197.17	1,228,126.00	79,071.17
Louisville	2,943,758.81	0.00	2,943,758.81	2,765,687.00	178,071.81
Monongahela	1,780,967.02	0.00	1,780,967.02	1,662,484.00	118,483.02
Ohio Power	7,882,131.60	0.00	7,882,131.60	7,357,737.00	524,394.60
Peninsula	3,383,880.81	0.00	3,383,880.81	3,158,755.00	225,125.81
So. Indiana	870,474.88	0.00	870,474.88	823,519.00	46,955.88
PJM Sponsors	(240,415.18)	0.00	(240,415.18)	(243,042.00)	2,626.82
Total	$ 50,866,075.61	$ 0.00	$ 50,866,075.61	$ 47,500,000.00	$ 3,366,075.61

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 4/11/2024

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 16,385,129.62	
Fuel Oil Consumed	254,817.79	
Other Fixed Fuel Related Costs*	1,187,991.68	
Total Account 501 (Fuel)		$ 17,827,939.09
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,184,878.60
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 19,012,817.69

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 19,012,817.69

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	**$ 19,012,817.69**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	85,889,000	0.1568998	$ 2,983,107.29
Buckeye	98,534,000	0.1799994	3,422,295.78
Cincinnati	49,267,000	0.0899997	1,711,147.89
Columbus	24,305,000	0.0443997	844,163.40
Dayton	26,823,000	0.0489996	931,620.46
Energy Harbor	26,550,000	0.0485008	922,136.87
Indiana	42,972,000	0.0785001	1,492,508.09
Kentucky	14,839,000	0.0271075	515,389.95
Louisville	33,416,000	0.0610435	1,160,608.94
Monongahela	19,159,000	0.0349992	665,433.41
Ohio Power	84,794,000	0.1548995	2,945,075.95
Peninsula	36,403,000	0.0665001	1,264,354.28
So. Indiana	11,384,000	0.0207960	395,390.56
PJM Sponsors	(6,922,000)	-0.0126449	(240,415.18)
Total	547,413,000	1.0000000	$ 19,012,817.69

Available Power Energy Summary

Available Energy Billed			547,413,000 kWh
Average Available Energy Cost	19,012,817.69 / 547,413,000	=	34.732 mills/kWh
Average Fuel Cost from Account 151 (Fuel Stock)			$ 16,639,947.41
Available Energy Billed			547,413,000 kWh
Average Fuel Cost from Account 151 (Fuel Stock)			30.397 mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	16,940,855.13
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		10,684,458.65
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		924,625.29
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		17,602.85
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,704,032.95
Total Demand Charge	$	30,480,474.87

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,211,155.14
2006-A Extended Notes, 6.40%, due June 15, 2040		132,564.31
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,525,260.67
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		98,456.67
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		316,256.17
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		657,911.13
2008-B Extended Notes, 6.91% due June 15, 2040		90,556.33
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		648,687.43
2008-C Extended Notes, 6.91% due June 15, 2040		92,129.67
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,727,522.97

Capital Lease Expense

Capital Lease Expense	$	74,295.34

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,619,453.29
428	Amortization of Debt Discount and Expense		142,970.75
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		452,487.66
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,214,911.70

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	3,924,125.12
TOTAL COMPONENT A	$	16,940,855.13

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses		
500	Operation, Supervision, and Engineering	$ 930,937.12
502	Steam Expenses	374,725.57
505	Electric Expenses	321,373.29
506	Miscellaneous Steam Power Expenses	880,451.59
507	Rents	5,515.00
510	Maintenance of Supervision and Engineering	470,378.66
511	Maintenance of Structures	319,935.56
512	Maintenance of Boiler Plant	4,444,219.22
513	Maintenance of Electric Plant	550,905.19
514	Maintenance of Miscellaneous Steam Plant	114,238.08
556	System Control and Load Dispatching	0.00
557	Other Expenses	1,487.78
	Total Production Expenses	$ 8,414,167.06
Transmission Expenses		
560	Operation Supervision and Engineering	$ 29,380.21
561	Load Dispatching	75,289.48
562	Station Expenses	325,866.69
563	Overhead Line Expenses	4,175.76
566	Miscellaneous Transmission Expenses	12,399.27
567	Rents	(2.14)
568	Maintenance of Supervision and Engineering	0.00
569	Maintenance of Structures	24,441.86
570	Maintenance of Station Equipment	2,065.10
571	Maintenance of Overhead Lines	19,277.05
573	Maintenance of Miscellaneous Transmission Plant	570.89
	Total Transmission Expenses	$ 493,464.17
Administrative and General Expenses		
920	Administrative and General Salaries	$ 382,302.04
921	Office Supplies and Expenses	269,127.49
922	Administrative and General Expenses Transferred - Credit	(60,505.76)
923	Outside Services Employed	510,981.91
924	Property Insurance	320,350.73
925	Injuries and Damages	126,935.98
926	Employee Pensions and Benefits	1,315,030.30
928	Regulatory Commission Expenses	0.00
929	Duplicate Charges - Credit	(4,694.91)
930	Miscellaneous General Expenses	106,125.89
931	Rents	1,791.92
935	Maintenance of General Plant	1,195.83
	Total Administrative and General Expenses	$ 2,968,641.42
	Total Operation and Maintenance Allocated to Component B	$ 11,876,272.65
Deduct Transmission Charge (Account 566.1)		(1,191,814.00)
Deduct Minimum Loading Event Charges - non-fuel		
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties		
	TOTAL COMPONENT B	$ 10,684,458.65

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 30,480,474.87**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 4,782,386.51
Buckeye	18.00	5,486,485.48
Cincinnati	9.00	2,743,242.74
Columbus	4.44	1,353,333.08
Dayton	4.90	1,493,543.27
Energy Harbor	4.85	1,478,303.03
Indiana	7.85	2,392,717.28
Kentucky	2.50	762,011.87
Louisville	5.63	1,716,050.74
Monongahela	3.50	1,066,816.62
Ohio Power	15.49	4,721,425.56
Peninsula	6.65	2,026,951.58
So. Indiana	1.50	457,207.11
Total	100.00	$ 30,480,474.87

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$**	**1,191,814.00**

Sponsoring Company	PPR		Transmission Charges Payable
Appalachian	15.69	$	186,995.62
Buckeye	18.00		214,526.52
Cincinnati	9.00		107,263.26
Columbus	4.44		52,916.54
Dayton	4.90		58,398.88
Energy Harbor	4.85		57,802.98
Indiana	7.85		93,557.40
Kentucky	2.50		29,795.35
Louisville	5.63		67,099.13
Monongahela	3.50		41,713.49
Ohio Power	15.49		184,611.99
Peninsula	6.65		79,255.63
So. Indiana	1.50		17,877.21
Total	100.00	$	1,191,814.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**418,518.93**
Energy Cost of PJM External Power		**(240,415.18)**
Net PJM External Charge/(Credit)	$	**178,103.75**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	31,416.23
Buckeye	19.92		36,049.03
Cincinnati	9.96		18,024.52
Columbus	4.91		8,885.58
Dayton	5.42		9,808.52
Energy Harbor	5.37		9,718.04
Indiana	8.69		15,726.21
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		7,003.50
Ohio Power	17.14		31,018.10
Peninsula	7.36		13,319.32
So. Indiana	0.00		-
Total	100.00	$	180,969.05

March 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,076,344.85	$ 0.00	$ 10,076,344.85	$ 10,135,758.00	$ (59,413.15)
Buckeye	11,559,840.00	0.00	11,559,840.00	11,628,002.00	(68,162.00)
Cincinnati	5,779,921.51	0.00	5,779,921.51	5,814,007.00	(34,085.49)
Columbus	2,851,425.54	0.00	2,851,425.54	2,868,236.00	(16,810.46)
Dayton	3,146,861.21	0.00	3,146,861.21	3,165,415.00	(18,553.79)
Energy Harbor	3,114,750.44	0.00	3,114,750.44	3,133,119.00	(18,368.56)
Indiana	5,041,365.74	0.00	5,041,365.74	5,071,092.00	(29,726.26)
Kentucky	1,662,656.58	0.00	1,662,656.58	1,675,768.00	(13,111.42)
Louisville	3,744,342.93	0.00	3,744,342.93	3,773,871.00	(29,528.07)
Monongahela	2,247,732.90	0.00	2,247,732.90	2,260,984.00	(13,251.10)
Ohio Power	9,947,874.18	0.00	9,947,874.18	10,006,532.00	(58,657.82)
Peninsula	4,270,705.06	0.00	4,270,705.06	4,295,889.00	(25,183.94)
So. Indiana	1,136,575.38	0.00	1,136,575.38	1,140,839.00	(4,263.62)
PJM Sponsors	(352,831.37)	0.00	(352,831.37)	(369,512.00)	16,680.63
Total	$ 64,227,564.95	$ 0.00	$ 64,227,564.95	$ 64,600,000.00	$ (372,435.05)

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 4/17/2023

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 25,626,287.00	
Fuel Oil Consumed	439,126.36	
Other Fixed Fuel Related Costs*	2,190,922.01	
Total Account 501 (Fuel)		$ 28,256,335.37
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		2,007,019.00
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 30,263,354.37

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 30,263,354.37

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	**$ 30,263,354.37**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	126,800,000	0.1569006	$ 4,748,338.46
Buckeye	145,468,000	0.1800001	5,447,406.81
Cincinnati	72,734,000	0.0900001	2,723,704.92
Columbus	35,882,000	0.0443999	1,343,689.91
Dayton	39,600,000	0.0490005	1,482,919.50
Energy Harbor	39,196,000	0.0485006	1,467,790.84
Indiana	63,440,000	0.0784998	2,375,667.27
Kentucky	21,686,000	0.0268340	812,086.85
Louisville	48,838,000	0.0604315	1,828,859.90
Monongahela	28,285,000	0.0349995	1,059,202.27
Ohio Power	125,183,000	0.1548997	4,687,784.51
Peninsula	53,742,000	0.0664996	2,012,500.96
So. Indiana	16,723,000	0.0206928	626,233.54
PJM Sponsors	(9,422,000)	-0.0116587	(352,831.37)
Total	808,155,000	1.0000000	$ 30,263,354.37

Available Power Energy Summary

Available Energy Billed			808,155,000	kWh
Average Available Energy Cost	30,263,354.37 / 808,155,000	=	37.448	mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 26,065,413.36	
Available Energy Billed	808,155,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)	32.253	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	17,195,542.41
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		12,652,820.76
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		976,415.20
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	32,725,678.37

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,211,155.14
2006-A Extended Notes, 6.40%, due June 15, 2040		132,564.31
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,525,260.67
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		98,456.67
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		316,256.17
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		657,911.10
2008-B Extended Notes, 6.91% due June 15, 2040		90,556.35
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		648,687.41
2008-C Extended Notes, 6.91% due June 15, 2040		92,129.65
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,727,522.92

Capital Lease Expense

Capital Lease Expense	$	74,578.99

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,619,453.27
428	Amortization of Debt Discount and Expense		148,153.84
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		619,217.90
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,386,825.01

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,006,615.49
TOTAL COMPONENT A	$	17,195,542.41

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses		
500	Operation, Supervision, and Engineering	$ 993,350.70
502	Steam Expenses	684,062.54
505	Electric Expenses	301,321.61
506	Miscellaneous Steam Power Expenses	1,093,681.85
507	Rents	5,515.00
510	Maintenance of Supervision and Engineering	610,352.66
511	Maintenance of Structures	463,542.85
512	Maintenance of Boiler Plant	5,059,074.32
513	Maintenance of Electric Plant	1,454,112.38
514	Maintenance of Miscellaneous Steam Plant	135,249.67
556	System Control and Load Dispatching	(2,199.92)
557	Other Expenses	0.00
	Total Production Expenses	$ 10,798,063.66
Transmission Expenses		
560	Operation Supervision and Engineering	$ 35,277.49
561	Load Dispatching	48,717.52
562	Station Expenses	138,147.27
563	Overhead Line Expenses	5,909.48
566	Miscellaneous Transmission Expenses	761.16
567	Rents	(2.14)
568	Maintenance of Supervision and Engineering	0.00
569	Maintenance of Structures	23,399.61
570	Maintenance of Station Equipment	26,997.15
571	Maintenance of Overhead Lines	3,081.65
573	Maintenance of Miscellaneous Transmission Plant	69.42
	Total Transmission Expenses	$ 282,358.61
Administrative and General Expenses		
920	Administrative and General Salaries	$ 424,706.18
921	Office Supplies and Expenses	(178,792.73)
922	Administrative and General Expenses Transferred - Credit	(50,268.61)
923	Outside Services Employed	793,586.01
924	Property Insurance	352,580.41
925	Injuries and Damages	86,253.53
926	Employee Pensions and Benefits	1,403,893.76
928	Regulatory Commission Expenses	0.00
929	Duplicate Charges - Credit	(12,061.87)
930	Miscellaneous General Expenses	49,031.87
931	Rents	147.39
935	Maintenance of General Plant	433.35
	Total Administrative and General Expenses	$ 2,869,509.29
	Total Operation and Maintenance Allocated to Component B	$ 13,949,931.56
Deduct Transmission Charge (Account 566.1)		(1,297,110.80)
Deduct Minimum Loading Event Charges - non-fuel		
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties		
	TOTAL COMPONENT B	$ 12,652,820.76

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	$	**32,725,678.37**

Sponsoring Company	PPR		Total Demand Charge Payable
Appalachian	15.69	$	5,134,658.94
Buckeye	18.00		5,890,622.11
Cincinnati	9.00		2,945,311.05
Columbus	4.44		1,453,020.12
Dayton	4.90		1,603,558.24
Energy Harbor	4.85		1,587,195.40
Indiana	7.85		2,568,965.75
Kentucky	2.50		818,141.96
Louisville	5.63		1,842,455.69
Monongahela	3.50		1,145,398.74
Ohio Power	15.49		5,069,207.58
Peninsula	6.65		2,176,257.61
So. Indiana	1.50		490,885.18
Total	100.00	$	32,725,678.37

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$**	**1,297,110.80**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 203,516.69
Buckeye	18.00	233,479.94
Cincinnati	9.00	116,739.97
Columbus	4.44	57,591.72
Dayton	4.90	63,558.43
Energy Harbor	4.85	62,909.87
Indiana	7.85	101,823.20
Kentucky	2.50	32,427.77
Louisville	5.63	73,027.34
Monongahela	3.50	45,398.88
Ohio Power	15.49	200,922.46
Peninsula	6.65	86,257.87
So. Indiana	1.50	19,456.66
Total	100.00	$ 1,297,110.80

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	**$**	**291,387.48**
Energy Cost of PJM External Power		**(352,831.37)**
Net PJM External Charge/(Credit)	**$**	**(61,443.89)**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	(10,169.24)
Buckeye	19.92		(11,668.86)
Cincinnati	9.96		(5,834.43)
Columbus	4.91		(2,876.21)
Dayton	5.42		(3,174.96)
Energy Harbor	5.37		(3,145.67)
Indiana	8.69		(5,090.48)
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		(2,266.99)
Ohio Power	17.14		(10,040.37)
Peninsula	7.36		(4,311.38)
So. Indiana	0.00		-
Total	100.00	$	(58,578.59)

April 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,741,528.46	$ 0.00	$ 10,741,528.46	$ 10,527,979.00	$ 213,549.46
Buckeye	12,322,974.13	0.00	12,322,974.13	12,077,990.00	244,984.13
Cincinnati	6,161,505.13	0.00	6,161,505.13	6,039,012.00	122,493.13
Columbus	3,039,656.09	0.00	3,039,656.09	2,979,223.00	60,433.09
Dayton	3,354,599.83	0.00	3,354,599.83	3,287,904.00	66,695.83
Energy Harbor	3,320,351.00	0.00	3,320,351.00	3,254,344.00	66,007.00
Indiana	5,374,197.09	0.00	5,374,197.09	5,267,359.00	106,838.09
Kentucky	1,829,531.26	0.00	1,829,531.26	1,787,309.00	42,222.26
Louisville	4,120,168.47	0.00	4,120,168.47	4,025,083.00	95,085.47
Monongahela	2,396,158.18	0.00	2,396,158.18	2,348,518.00	47,640.18
Ohio Power	10,604,634.94	0.00	10,604,634.94	10,393,806.00	210,828.94
Peninsula	4,552,654.99	0.00	4,552,654.99	4,462,147.00	90,507.99
So. Indiana	1,202,252.16	0.00	1,202,252.16	1,172,364.00	29,888.16
PJM Sponsors	(546,651.12)	0.00	(546,651.12)	(523,038.00)	(23,613.12)
Total	$ 68,473,560.61	$ 0.00	$ 68,473,560.61	$ 67,100,000.00	$ 1,373,560.61

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 25,628,193.50	
Fuel Oil Consumed	287,350.87	
Other Fixed Fuel Related Costs*	1,410,135.64	
Total Account 501 (Fuel)		$ 27,325,680.01
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		2,786,203.01
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 30,111,883.02

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 30,111,883.02

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	$	**30,111,883.02**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	130,444,000	0.1568996	$ 4,724,542.40
Buckeye	149,649,000	0.1799996	5,420,126.90
Cincinnati	74,825,000	0.0900004	2,710,081.52
Columbus	36,913,000	0.0443994	1,336,949.54
Dayton	40,738,000	0.0490002	1,475,488.29
Energy Harbor	40,322,000	0.0484998	1,460,420.30
Indiana	65,264,000	0.0785003	2,363,791.85
Kentucky	23,953,000	0.0288110	867,553.46
Louisville	53,944,000	0.0648845	1,953,794.47
Monongahela	29,099,000	0.0350006	1,053,933.97
Ohio Power	128,782,000	0.1549006	4,664,348.75
Peninsula	55,287,000	0.0664999	2,002,437.21
So. Indiana	17,258,000	0.0207581	625,065.48
PJM Sponsors	(15,093,000)	-0.0181540	(546,651.12)
Total	831,385,000	1.0000000	$ 30,111,883.02

Available Power Energy Summary

Available Energy Billed			831,385,000 kWh
Average Available Energy Cost	30,111,883.02 / 831,385,000	=	36.219 mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 25,915,544.37
Available Energy Billed	831,385,000 kWh
Average Fuel Cost from Account 151 (Fuel Stock)	31.172 mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	17,252,968.20
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		16,672,478.74
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		1,344,093.74
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	37,170,440.68

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,211,155.14
2006-A Extended Notes, 6.40%, due June 15, 2040		132,564.31
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,525,260.67
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		98,456.67
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		316,256.17
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		679,984.04
2008-B Extended Notes, 6.91% due June 15, 2040		93,685.00
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		670,450.89
2008-C Extended Notes, 6.91% due June 15, 2040		95,312.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,777,671.17

Capital Lease Expense	$	74,863.94

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,569,305.07
428	Amortization of Debt Discount and Expense		142,970.75
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		646,529.48
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,358,805.30

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,041,627.79
TOTAL COMPONENT A	$	17,252,968.20

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses		
500	Operation, Supervision, and Engineering	$ 1,780,281.10
502	Steam Expenses	1,616,667.83
505	Electric Expenses	829,207.18
506	Miscellaneous Steam Power Expenses	996,680.41
507	Rents	5,515.00
510	Maintenance of Supervision and Engineering	943,067.65
511	Maintenance of Structures	407,590.84
512	Maintenance of Boiler Plant	4,945,982.25
513	Maintenance of Electric Plant	856,591.86
514	Maintenance of Miscellaneous Steam Plant	155,486.49
556	System Control and Load Dispatching	(5,088.27)
557	Other Expenses	0.00
	Total Production Expenses	$ 12,531,982.34
Transmission Expenses		
560	Operation Supervision and Engineering	$ 141,104.97
561	Load Dispatching	214,809.92
562	Station Expenses	132,552.86
563	Overhead Line Expenses	13,487.57
566	Miscellaneous Transmission Expenses	20,482.35
567	Rents	(2.14)
568	Maintenance of Supervision and Engineering	7,725.22
569	Maintenance of Structures	22,153.11
570	Maintenance of Station Equipment	74,577.37
571	Maintenance of Overhead Lines	12,233.46
573	Maintenance of Miscellaneous Transmission Plant	20,418.40
	Total Transmission Expenses	$ 659,543.09
Administrative and General Expenses		
920	Administrative and General Salaries	$ 1,285,529.91
921	Office Supplies and Expenses	138,490.59
922	Administrative and General Expenses Transferred - Credit	(16,955.80)
923	Outside Services Employed	749,108.38
924	Property Insurance	345,747.81
925	Injuries and Damages	572,926.53
926	Employee Pensions and Benefits	1,672,811.61
928	Regulatory Commission Expenses	0.00
929	Duplicate Charges - Credit	(9,572.88)
930	Miscellaneous General Expenses	49,534.99
931	Rents	1,214.07
935	Maintenance of General Plant	789.30
	Total Administrative and General Expenses	$ 4,789,624.51
	Total Operation and Maintenance Allocated to Component B	$ 17,981,149.94
Deduct Transmission Charge (Account 566.1)		(1,308,671.20)
Deduct Minimum Loading Event Charges - non-fuel		
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties		
	TOTAL COMPONENT B	$ 16,672,478.74

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	$	**37,170,440.68**

Sponsoring Company	PPR		Total Demand Charge Payable
Appalachian	15.69	$	5,832,042.14
Buckeye	18.00		6,690,679.32
Cincinnati	9.00		3,345,339.66
Columbus	4.44		1,650,367.57
Dayton	4.90		1,821,351.59
Energy Harbor	4.85		1,802,766.37
Indiana	7.85		2,917,879.59
Kentucky	2.50		929,261.02
Louisville	5.63		2,092,695.81
Monongahela	3.50		1,300,965.43
Ohio Power	15.49		5,757,701.26
Peninsula	6.65		2,471,834.31
So. Indiana	1.50		557,556.61
Total	100.00	$	37,170,440.68

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$**	**1,308,671.20**

Sponsoring Company	PPR		Transmission Charges Payable
Appalachian	15.69	$	205,330.51
Buckeye	18.00		235,560.82
Cincinnati	9.00		117,780.41
Columbus	4.44		58,105.00
Dayton	4.90		64,124.89
Energy Harbor	4.85		63,470.55
Indiana	7.85		102,730.69
Kentucky	2.50		32,716.78
Louisville	5.63		73,678.19
Monongahela	3.50		45,803.49
Ohio Power	15.49		202,713.17
Peninsula	6.65		87,026.63
So. Indiana	1.50		19,630.07
Total	100.00	$	1,308,671.20

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**426,351.53**
Energy Cost of PJM External Power		**(546,651.12)**
Net PJM External Charge/(Credit)	$	**(120,299.59)**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	(20,386.59)
Buckeye	19.92		(23,392.91)
Cincinnati	9.96		(11,696.46)
Columbus	4.91		(5,766.02)
Dayton	5.42		(6,364.94)
Energy Harbor	5.37		(6,306.22)
Indiana	8.69		(10,205.04)
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		(4,544.71)
Ohio Power	17.14		(20,128.24)
Peninsula	7.36		(8,643.16)
So. Indiana	0.00		-
Total	100.00	$	(117,434.29)

May 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 9,086,684.26	$ 0.00	$ 9,086,684.26	$ 8,864,836.00	$ 221,848.26
Buckeye	10,424,519.14	0.00	10,424,519.14	10,170,011.00	254,508.14
Cincinnati	5,212,241.08	0.00	5,212,241.08	5,084,983.00	127,258.08
Columbus	2,571,362.89	0.00	2,571,362.89	2,508,585.00	62,777.89
Dayton	2,837,779.38	0.00	2,837,779.38	2,768,495.00	69,284.38
Energy Harbor	2,808,822.48	0.00	2,808,822.48	2,740,243.00	68,579.48
Indiana	4,546,261.51	0.00	4,546,261.51	4,435,266.00	110,995.51
Kentucky	1,384,955.75	0.00	1,384,955.75	1,349,997.00	34,958.75
Louisville	3,118,877.11	0.00	3,118,877.11	3,040,150.00	78,727.11
Monongahela	2,026,973.82	0.00	2,026,973.82	1,977,484.00	49,489.82
Ohio Power	8,970,854.32	0.00	8,970,854.32	8,751,832.00	219,022.32
Peninsula	3,851,285.86	0.00	3,851,285.86	3,757,257.00	94,028.86
So. Indiana	931,509.71	0.00	931,509.71	906,113.00	25,396.71
PJM Sponsors	141,723.07	0.00	141,723.07	144,748.00	(3,024.93)
Total	$ 57,913,850.38	$ 0.00	$ 57,913,850.38	$ 56,500,000.00	$ 1,413,850.38

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 6/16/2023

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 17,023,984.82	
Fuel Oil Consumed	293,667.54	
Other Fixed Fuel Related Costs*	1,401,367.47	
Total Account 501 (Fuel)		$ 18,719,019.83
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,826,510.18
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 20,545,530.01

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 20,545,530.01

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	$	**20,545,530.01**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	82,840,000	0.1568993	$ 3,223,579.28
Buckeye	95,037,000	0.1800004	3,698,203.62
Cincinnati	47,518,000	0.0899993	1,849,083.32
Columbus	23,442,000	0.0443992	912,205.10
Dayton	25,871,000	0.0489998	1,006,726.86
Energy Harbor	25,607,000	0.0484998	996,454.10
Indiana	41,447,000	0.0785008	1,612,840.54
Kentucky	11,584,000	0.0219401	450,770.98
Louisville	26,086,000	0.0494070	1,015,093.00
Monongahela	18,479,000	0.0349993	719,079.17
Ohio Power	81,784,000	0.1548992	3,182,486.16
Peninsula	35,111,000	0.0665004	1,366,285.96
So. Indiana	9,534,000	0.0180574	370,998.85
PJM Sponsors	3,642,000	0.0068980	141,723.07
Total	527,982,000	1.0000000	$ 20,545,530.01

Available Power Energy Summary

Available Energy Billed			527,982,000	kWh
Average Available Energy Cost	20,545,530.01 / 527,982,000	=	38.913	mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 17,317,652.36	
Available Energy Billed	527,982,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)	32.800	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	17,607,698.68
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		15,661,219.93
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		1,015,854.52
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		1,901.84
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	36,187,574.97

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,211,155.14
2006-A Extended Notes, 6.40%, due June 15, 2040		132,564.31
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,525,260.65
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		98,456.65
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		316,256.15
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		679,984.04
2008-B Extended Notes, 6.91% due June 15, 2040		93,685.00
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		670,450.89
2008-C Extended Notes, 6.91% due June 15, 2040		95,312.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,777,671.11

Capital Lease Expense	$	83,478.95

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,569,305.11
428	Amortization of Debt Discount and Expense		145,622.35
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		627,620.98
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,342,548.44

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,404,000.18
TOTAL COMPONENT A	$	17,607,698.68

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses		
500	Operation, Supervision, and Engineering	$ 1,024,854.53
502	Steam Expenses	683,992.00
505	Electric Expenses	341,893.60
506	Miscellaneous Steam Power Expenses	668,428.51
507	Rents	5,515.00
510	Maintenance of Supervision and Engineering	644,002.89
511	Maintenance of Structures	502,931.95
512	Maintenance of Boiler Plant	6,891,091.71
513	Maintenance of Electric Plant	1,792,484.60
514	Maintenance of Miscellaneous Steam Plant	126,793.18
556	System Control and Load Dispatching	1,880.17
557	Other Expenses	0.00
	Total Production Expenses	$ 12,683,868.14
Transmission Expenses		
560	Operation Supervision and Engineering	$ 36,661.35
561	Load Dispatching	80,222.12
562	Station Expenses	61,175.49
563	Overhead Line Expenses	135,570.68
566	Miscellaneous Transmission Expenses	7,567.20
567	Rents	8.56
568	Maintenance of Supervision and Engineering	0.00
569	Maintenance of Structures	19,230.74
570	Maintenance of Station Equipment	42,589.56
571	Maintenance of Overhead Lines	14,984.02
573	Maintenance of Miscellaneous Transmission Plant	(87.59)
	Total Transmission Expenses	$ 397,922.13
Administrative and General Expenses		
920	Administrative and General Salaries	$ 458,031.45
921	Office Supplies and Expenses	81,123.32
922	Administrative and General Expenses Transferred - Credit	(11,621.03)
923	Outside Services Employed	935,640.72
924	Property Insurance	354,957.91
925	Injuries and Damages	277,520.10
926	Employee Pensions and Benefits	1,571,373.15
928	Regulatory Commission Expenses	1,660.47
929	Duplicate Charges - Credit	0.00
930	Miscellaneous General Expenses	79,032.76
931	Rents	2,165.98
935	Maintenance of General Plant	9,360.83
	Total Administrative and General Expenses	$ 3,759,245.66
	Total Operation and Maintenance Allocated to Component B	$ 16,841,035.93
Deduct Transmission Charge (Account 566.1)		(1,179,816.00)
Deduct Minimum Loading Event Charges - non-fuel		
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties		
	TOTAL COMPONENT B	$ 15,661,219.93

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	$	**36,187,574.97**

Sponsoring Company	PPR		Total Demand Charge Payable
Appalachian	15.69	$	5,677,830.51
Buckeye	18.00		6,513,763.50
Cincinnati	9.00		3,256,881.75
Columbus	4.44		1,606,728.33
Dayton	4.90		1,773,191.17
Energy Harbor	4.85		1,755,097.39
Indiana	7.85		2,840,724.64
Kentucky	2.50		904,689.37
Louisville	5.63		2,037,360.47
Monongahela	3.50		1,266,565.12
Ohio Power	15.49		5,605,455.36
Peninsula	6.65		2,406,473.74
So. Indiana	1.50		542,813.62
Total	100.00	$	36,187,574.97

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$ 1,179,816.00**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 185,113.13
Buckeye	18.00	212,366.88
Cincinnati	9.00	106,183.44
Columbus	4.44	52,383.83
Dayton	4.90	57,810.98
Energy Harbor	4.85	57,221.08
Indiana	7.85	92,615.56
Kentucky	2.50	29,495.40
Louisville	5.63	66,423.64
Monongahela	3.50	41,293.56
Ohio Power	15.49	182,753.50
Peninsula	6.65	78,457.76
So. Indiana	1.50	17,697.24
Total	100.00	$ 1,179,816.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**(143,658.97)**
Energy Cost of PJM External Power		**141,723.07**
Net PJM External Charge/(Credit)	$	**(1,935.90)**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	161.34
Buckeye	19.92		185.14
Cincinnati	9.96		92.57
Columbus	4.91		45.63
Dayton	5.42		50.37
Energy Harbor	5.37		49.91
Indiana	8.69		80.77
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		35.97
Ohio Power	17.14		159.30
Peninsula	7.36		68.40
So. Indiana	0.00		-
Total	100.00	$	929.40

June 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,630,599.67	$ 0.00	$ 10,630,599.67	$ 10,590,745.00	$ 39,854.67
Buckeye	12,195,721.28	0.00	12,195,721.28	12,149,997.00	45,724.28
Cincinnati	6,097,859.16	0.00	6,097,859.16	6,074,999.00	22,860.16
Columbus	3,008,266.10	0.00	3,008,266.10	2,996,989.00	11,277.10
Dayton	3,319,949.61	0.00	3,319,949.61	3,307,503.00	12,446.61
Energy Harbor	3,286,079.54	0.00	3,286,079.54	3,273,759.00	12,320.54
Indiana	5,318,688.39	0.00	5,318,688.39	5,298,747.00	19,941.39
Kentucky	1,736,630.44	0.00	1,736,630.44	1,730,522.00	6,108.44
Louisville	3,910,978.59	0.00	3,910,978.59	3,897,225.00	13,753.59
Monongahela	2,371,387.23	0.00	2,371,387.23	2,362,497.00	8,890.23
Ohio Power	10,495,082.99	0.00	10,495,082.99	10,455,735.00	39,347.99
Peninsula	4,505,645.67	0.00	4,505,645.67	4,488,752.00	16,893.67
So. Indiana	1,084,333.21	0.00	1,084,333.21	1,081,195.00	3,138.21
PJM Sponsors	(209,236.62)	0.00	(209,236.62)	(208,665.00)	(571.62)
Total	$ 67,751,985.26	$ 0.00	$ 67,751,985.26	$ 67,500,000.00	$ 251,985.26

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 3/5/2024

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 25,988,583.69	
Fuel Oil Consumed	293,830.35	
Other Fixed Fuel Related Costs*	1,393,812.89	
Total Account 501 (Fuel)		$ 27,676,226.93
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,974,968.32
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 29,651,195.25

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 29,651,195.25

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	**$ 29,651,195.25**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	131,850,000	0.1568998	$ 4,652,266.60
Buckeye	151,262,000	0.1799999	5,337,212.18
Cincinnati	75,631,000	0.0899999	2,668,604.61
Columbus	37,311,000	0.0443996	1,316,501.21
Dayton	41,177,000	0.0490001	1,452,911.53
Energy Harbor	40,757,000	0.0485003	1,438,091.86
Indiana	65,967,000	0.0784999	2,327,615.86
Kentucky	22,236,000	0.0264606	784,588.42
Louisville	50,078,000	0.0595922	1,766,979.96
Monongahela	29,412,000	0.0349999	1,037,788.87
Ohio Power	130,169,000	0.1548995	4,592,955.32
Peninsula	55,883,000	0.0665001	1,971,807.45
So. Indiana	14,542,000	0.0173048	513,108.00
PJM Sponsors	(5,930,000)	-0.0070566	(209,236.62)
Total	840,345,000	1.0000000	$ 29,651,195.25

Available Power Energy Summary

Available Energy Billed		840,345,000	kWh
Average Available Energy Cost	29,651,195.25 / 840,345,000 =	35.285	mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 26,282,414.04	
Available Energy Billed	840,345,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)	31.276	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	19,381,644.29
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		14,513,163.85
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		977,382.69
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	36,773,090.83

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,211,155.14
2006-A Extended Notes, 6.40%, due June 15, 2040		132,564.31
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,570,255.83
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		101,656.50
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		325,617.33
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		679,984.04
2008-B Extended Notes, 6.91% due June 15, 2040		93,685.00
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		670,450.89
2008-C Extended Notes, 6.91% due June 15, 2040		95,312.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,835,227.32

Capital Lease Expense	$	69,193.43

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,511,748.91
428	Amortization of Debt Discount and Expense		142,970.75
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		1,157,840.95
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,812,560.61

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	5,664,662.93

TOTAL COMPONENT A	$	19,381,644.29

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	978,669.71
502	Steam Expenses		869,162.88
505	Electric Expenses		321,514.65
506	Miscellaneous Steam Power Expenses		1,007,985.58
507	Rents		12,405.00
510	Maintenance of Supervision and Engineering		695,534.24
511	Maintenance of Structures		423,089.32
512	Maintenance of Boiler Plant		6,510,435.49
513	Maintenance of Electric Plant		613,354.58
514	Maintenance of Miscellaneous Steam Plant		132,194.08
556	System Control and Load Dispatching		341.04
557	Other Expenses		0.00
	Total Production Expenses	$	11,564,686.57
Transmission Expenses			
560	Operation Supervision and Engineering	$	36,618.21
561	Load Dispatching		60,622.82
562	Station Expenses		145,107.62
563	Overhead Line Expenses		36,631.08
566	Miscellaneous Transmission Expenses		1,310.96
567	Rents		87.30
568	Maintenance of Supervision and Engineering		0.00
569	Maintenance of Structures		161,201.87
570	Maintenance of Station Equipment		112,075.29
571	Maintenance of Overhead Lines		4,684.02
573	Maintenance of Miscellaneous Transmission Plant		19,425.24
	Total Transmission Expenses	$	577,764.41
Administrative and General Expenses			
920	Administrative and General Salaries	$	447,163.42
921	Office Supplies and Expenses		158,969.13
922	Administrative and General Expenses Transferred - Credit		(9,757.77)
923	Outside Services Employed		827,100.49
924	Property Insurance		337,986.52
925	Injuries and Damages		275,430.89
926	Employee Pensions and Benefits		1,546,444.80
928	Regulatory Commission Expenses		11,862.42
929	Duplicate Charges - Credit		(1,343.49)
930	Miscellaneous General Expenses		68,499.46
931	Rents		147.39
935	Maintenance of General Plant		16,799.61
	Total Administrative and General Expenses	$	3,679,302.87
	Total Operation and Maintenance Allocated to Component B	$	15,821,753.85
Deduct Transmission Charge (Account 566.1)			(1,308,590.00)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	14,513,163.85

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 36,773,090.83**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 5,769,697.95
Buckeye	18.00	6,619,156.35
Cincinnati	9.00	3,309,578.18
Columbus	4.44	1,632,725.23
Dayton	4.90	1,801,881.45
Energy Harbor	4.85	1,783,494.91
Indiana	7.85	2,886,687.63
Kentucky	2.50	919,327.27
Louisville	5.63	2,070,325.01
Monongahela	3.50	1,287,058.18
Ohio Power	15.49	5,696,151.77
Peninsula	6.65	2,445,410.54
So. Indiana	1.50	551,596.36
Total	100.00	$ 36,773,090.83

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$**	**1,308,590.00**

Sponsoring Company	PPR		Transmission Charges Payable
Appalachian	15.69	$	205,317.77
Buckeye	18.00		235,546.20
Cincinnati	9.00		117,773.10
Columbus	4.44		58,101.40
Dayton	4.90		64,120.91
Energy Harbor	4.85		63,466.61
Indiana	7.85		102,724.31
Kentucky	2.50		32,714.75
Louisville	5.63		73,673.62
Monongahela	3.50		45,800.65
Ohio Power	15.49		202,700.59
Peninsula	6.65		87,021.24
So. Indiana	1.50		19,628.85
Total	100.00	$	1,308,590.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**225,480.50**
Energy Cost of PJM External Power		**(209,236.62)**
Net PJM External Charge/(Credit)	$	**16,243.88**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	3,317.35
Buckeye	19.92		3,806.55
Cincinnati	9.96		1,903.27
Columbus	4.91		938.26
Dayton	5.42		1,035.72
Energy Harbor	5.37		1,026.16
Indiana	8.69		1,660.59
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		739.53
Ohio Power	17.14		3,275.31
Peninsula	7.36		1,406.44
So. Indiana	0.00		-
Total	100.00	$	19,109.18

July 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,333,105.37	$ 0.00	$ 10,333,105.37	$ 10,214,197.00	$ 118,908.37
Buckeye	11,854,445.65	0.00	11,854,445.65	11,718,009.00	136,436.65
Cincinnati	5,927,204.84	0.00	5,927,204.84	5,858,986.00	68,218.84
Columbus	2,924,066.63	0.00	2,924,066.63	2,890,430.00	33,636.63
Dayton	3,227,017.91	0.00	3,227,017.91	3,189,889.00	37,128.91
Energy Harbor	3,194,108.66	0.00	3,194,108.66	3,157,333.00	36,775.66
Indiana	5,169,867.59	0.00	5,169,867.59	5,110,355.00	59,512.59
Kentucky	1,542,978.61	0.00	1,542,978.61	1,658,727.00	(115,748.39)
Louisville	3,474,754.03	0.00	3,474,754.03	3,735,420.00	(260,665.97)
Monongahela	2,304,999.68	0.00	2,304,999.68	2,278,484.00	26,515.68
Ohio Power	10,201,379.64	0.00	10,201,379.64	10,083,981.00	117,398.64
Peninsula	4,379,575.09	0.00	4,379,575.09	4,329,167.00	50,408.09
So. Indiana	1,035,050.76	0.00	1,035,050.76	1,116,610.00	(81,559.24)
PJM Sponsors	(234,534.00)	0.00	(234,534.00)	(241,588.00)	7,054.00
Total	$ 65,334,020.46	$ 0.00	$ 65,334,020.46	$ 65,100,000.00	$ 234,020.46

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 3/5/2024

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 28,589,490.54	
Fuel Oil Consumed	228,606.20	
Other Fixed Fuel Related Costs*	1,599,274.16	
Total Account 501 (Fuel)		$ 30,417,370.90
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		2,287,159.18
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 32,704,530.08

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 32,704,530.08

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	**$ 32,704,530.08**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	144,314,000	0.1569002	$ 5,131,347.31
Buckeye	165,561,000	0.1800003	5,886,825.23
Cincinnati	82,780,000	0.0899996	2,943,394.63
Columbus	40,838,000	0.0443997	1,452,071.32
Dayton	45,069,000	0.0489997	1,602,512.16
Energy Harbor	44,609,000	0.0484995	1,586,153.36
Indiana	72,203,000	0.0785001	2,567,308.88
Kentucky	23,825,000	0.0259029	847,142.17
Louisville	53,653,000	0.0583323	1,907,730.46
Monongahela	32,192,000	0.0349996	1,144,645.47
Ohio Power	142,474,000	0.1548997	5,065,921.90
Peninsula	61,166,000	0.0665005	2,174,867.60
So. Indiana	17,694,000	0.0192372	629,143.59
PJM Sponsors	(6,596,000)	-0.0071713	(234,534.00)
Total	919,782,000	1.0000000	$ 32,704,530.08

Available Power Energy Summary

Available Energy Billed		919,782,000	kWh
Average Available Energy Cost	32,704,530.08 / 919,782,000 =	35.557	mills/kWh
Average Fuel Cost from Account 151 (Fuel Stock)		$ 28,818,096.74	
Available Energy Billed		919,782,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)		31.331	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	17,679,055.91
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		10,698,583.45
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		989,071.33
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	31,267,610.69

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,211,155.11
2006-A Extended Notes, 6.40%, due June 15, 2040		132,564.29
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,570,255.83
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		101,656.50
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		325,617.33
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		679,984.04
2008-B Extended Notes, 6.91% due June 15, 2040		93,685.00
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		670,450.89
2008-C Extended Notes, 6.91% due June 15, 2040		95,312.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,835,227.27

Capital Lease Expense

Capital Lease Expense	$	69,501.53

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,511,748.89
428	Amortization of Debt Discount and Expense		144,198.68
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		849,405.23
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,505,352.80

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,268,974.31
TOTAL COMPONENT A	$	17,679,055.91

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	908,004.75
502	Steam Expenses		853,950.71
505	Electric Expenses		339,298.05
506	Miscellaneous Steam Power Expenses		930,709.21
507	Rents		0.00
510	Maintenance of Supervision and Engineering		738,258.99
511	Maintenance of Structures		429,288.03
512	Maintenance of Boiler Plant		2,966,195.06
513	Maintenance of Electric Plant		369,045.24
514	Maintenance of Miscellaneous Steam Plant		115,115.09
556	System Control and Load Dispatching		2,214.37
557	Other Expenses		0.00
	Total Production Expenses	$	7,652,079.50
Transmission Expenses			
560	Operation Supervision and Engineering	$	36,962.20
561	Load Dispatching		52,809.31
562	Station Expenses		59,050.27
563	Overhead Line Expenses		1,310.97
566	Miscellaneous Transmission Expenses		5,714.43
567	Rents		(87.30)
568	Maintenance of Supervision and Engineering		0.00
569	Maintenance of Structures		(77,351.88)
570	Maintenance of Station Equipment		124,428.12
571	Maintenance of Overhead Lines		94.20
573	Maintenance of Miscellaneous Transmission Plant		267.89
	Total Transmission Expenses	$	203,198.21
Administrative and General Expenses			
920	Administrative and General Salaries	$	474,755.79
921	Office Supplies and Expenses		99,906.48
922	Administrative and General Expenses Transferred - Credit		(9,276.92)
923	Outside Services Employed		458,819.00
924	Property Insurance		187,637.19
925	Injuries and Damages		283,506.67
926	Employee Pensions and Benefits		1,500,806.06
928	Regulatory Commission Expenses		1,099,389.00
929	Duplicate Charges - Credit		(914.07)
930	Miscellaneous General Expenses		87,530.05
931	Rents		288.81
935	Maintenance of General Plant		1,488.88
	Total Administrative and General Expenses	$	4,183,936.94
	Total Operation and Maintenance Allocated to Component B	$	12,039,214.65
Deduct Transmission Charge (Account 566.1)			(1,340,631.20)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	10,698,583.45

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 31,267,610.69**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 4,905,888.12
Buckeye	18.00	5,628,169.92
Cincinnati	9.00	2,814,084.96
Columbus	4.44	1,388,281.92
Dayton	4.90	1,532,112.92
Energy Harbor	4.85	1,516,479.12
Indiana	7.85	2,454,507.44
Kentucky	2.50	781,690.27
Louisville	5.63	1,760,366.48
Monongahela	3.50	1,094,366.37
Ohio Power	15.49	4,843,352.90
Peninsula	6.65	2,079,296.11
So. Indiana	1.50	469,014.16
Total	100.00	$ 31,267,610.69

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$ 1,340,631.20**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 210,345.03
Buckeye	18.00	241,313.62
Cincinnati	9.00	120,656.81
Columbus	4.44	59,524.03
Dayton	4.90	65,690.93
Energy Harbor	4.85	65,020.61
Indiana	7.85	105,239.55
Kentucky	2.50	33,515.78
Louisville	5.63	75,477.54
Monongahela	3.50	46,922.09
Ohio Power	15.49	207,663.77
Peninsula	6.65	89,151.97
So. Indiana	1.50	20,109.47
Total	100.00	$ 1,340,631.20

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**252,917.19**
Energy Cost of PJM External Power		**(234,534.00)**
Net PJM External Charge/(Credit)	$	**18,383.19**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	3,688.74
Buckeye	19.92		4,232.70
Cincinnati	9.96		2,116.35
Columbus	4.91		1,043.30
Dayton	5.42		1,151.67
Energy Harbor	5.37		1,141.04
Indiana	8.69		1,846.49
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		822.32
Ohio Power	17.14		3,641.99
Peninsula	7.36		1,563.89
So. Indiana	0.00		-
Total	100.00	$	21,248.49

Ohio Valley Electric Corporation
Available Power Statement

One time billing adjustment for Non-PJM Sponsors based on OVEC Unit performance during December 2022 PJM Performance Assessment Interval event.

Sponsoring Company	PJM PPR	Total Demand Charge Payable
Appalachian	17.36	$ 81,836.17
Buckeye	19.92	93,904.18
Cincinnati	9.96	46,952.09
Columbus	4.91	23,146.06
Dayton	5.42	25,550.23
Energy Harbor	5.37	25,314.53
Indiana	8.69	40,965.23
Kentucky	0.00	(119,369.61)
Louisville	0.00	(268,820.45)
Monongahela	3.87	18,243.43
Ohio Power	17.14	80,799.08
Peninsula	7.36	34,695.52
So. Indiana	0.00	(83,216.46)
Total	100.00	$ 0.00

August 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,454,731.84	$ 0.00	$ 10,454,731.84	$ 10,371,075.00	$ 83,656.84
Buckeye	11,993,985.28	0.00	11,993,985.28	11,898,011.00	95,974.28
Cincinnati	5,996,975.33	0.00	5,996,975.33	5,948,987.00	47,988.33
Columbus	2,958,512.67	0.00	2,958,512.67	2,934,839.00	23,673.67
Dayton	3,265,010.00	0.00	3,265,010.00	3,238,883.00	26,127.00
Energy Harbor	3,231,701.73	0.00	3,231,701.73	3,205,841.00	25,860.73
Indiana	5,230,716.60	0.00	5,230,716.60	5,188,860.00	41,856.60
Kentucky	1,718,713.11	0.00	1,718,713.11	1,706,361.00	12,352.11
Louisville	3,870,602.49	0.00	3,870,602.49	3,842,788.00	27,814.49
Monongahela	2,332,160.70	0.00	2,332,160.70	2,313,500.00	18,660.70
Ohio Power	10,321,487.98	0.00	10,321,487.98	10,238,897.00	82,590.98
Peninsula	4,431,111.15	0.00	4,431,111.15	4,395,651.00	35,460.15
So. Indiana	1,128,212.10	0.00	1,128,212.10	1,122,243.00	5,969.10
PJM Sponsors	(304,788.26)	0.00	(304,788.26)	(305,936.00)	1,147.74
Total	$ 66,629,132.72	$ 0.00	$ 66,629,132.72	$ 66,100,000.00	$ 529,132.72

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Date Issued 3/5/2024

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 27,931,590.05	
Fuel Oil Consumed	261,219.00	
Other Fixed Fuel Related Costs*	1,342,645.05	
Total Account 501 (Fuel)		$ 29,535,454.10
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,951,912.05
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 31,487,366.15

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 31,487,366.15

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	**$ 31,487,366.15**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	139,690,000	0.1568995	$ 4,940,352.01
Buckeye	160,257,000	0.1800003	5,667,735.35
Cincinnati	80,128,000	0.0899996	2,833,850.36
Columbus	39,530,000	0.0444000	1,398,039.06
Dayton	43,625,000	0.0489995	1,542,865.20
Energy Harbor	43,180,000	0.0484997	1,527,127.81
Indiana	69,890,000	0.0785003	2,471,767.69
Kentucky	23,783,000	0.0267130	841,122.01
Louisville	53,561,000	0.0601596	1,894,267.35
Monongahela	31,161,000	0.0350000	1,102,057.82
Ohio Power	137,910,000	0.1549002	4,877,399.31
Peninsula	59,206,000	0.0665001	2,093,913.00
So. Indiana	17,012,000	0.0191079	601,657.44
PJM Sponsors	(8,618,000)	-0.0096797	(304,788.26)
Total	890,315,000	1.0000000	$ 31,487,366.15

Available Power Energy Summary

Available Energy Billed		890,315,000	kWh
Average Available Energy Cost	31,487,366.15 / 890,315,000 =	35.367	mills/kWh
Average Fuel Cost from Account 151 (Fuel Stock)		$ 28,192,809.05	
Available Energy Billed		890,315,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)		31.666	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	17,510,417.16
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		13,381,900.36
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		978,732.48
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		2,040.64
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	33,773,990.64

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,275,278.63
2006-A Extended Notes, 6.40%, due June 15, 2040		136,806.36
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,570,255.83
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		101,656.50
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		325,617.33
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		679,984.04
2008-B Extended Notes, 6.91% due June 15, 2040		93,685.00
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		670,450.89
2008-C Extended Notes, 6.91% due June 15, 2040		95,312.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,903,592.86

Capital Lease Expense

Capital Lease Expense	$	72,981.53

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,488,383.36
428	Amortization of Debt Discount and Expense		144,198.68
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		873,272.77
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,505,854.81

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,027,987.96
TOTAL COMPONENT A	$	17,510,417.16

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	1,074,324.43
502	Steam Expenses		662,682.68
505	Electric Expenses		340,753.21
506	Miscellaneous Steam Power Expenses		1,365,386.72
507	Rents		6,890.00
510	Maintenance of Supervision and Engineering		662,636.44
511	Maintenance of Structures		709,890.60
512	Maintenance of Boiler Plant		4,477,748.44
513	Maintenance of Electric Plant		574,692.58
514	Maintenance of Miscellaneous Steam Plant		129,518.69
556	System Control and Load Dispatching		937.77
557	Other Expenses		0.00
	Total Production Expenses	$	10,005,461.56
Transmission Expenses			
560	Operation Supervision and Engineering	$	35,945.15
561	Load Dispatching		61,188.36
562	Station Expenses		107,333.52
563	Overhead Line Expenses		50,774.25
566	Miscellaneous Transmission Expenses		3,342.03
567	Rents		146.16
568	Maintenance of Supervision and Engineering		0.00
569	Maintenance of Structures		19,912.11
570	Maintenance of Station Equipment		122,931.26
571	Maintenance of Overhead Lines		217.53
573	Maintenance of Miscellaneous Transmission Plant		899.70
	Total Transmission Expenses	$	402,690.07
Administrative and General Expenses			
920	Administrative and General Salaries	$	468,867.88
921	Office Supplies and Expenses		77,527.52
922	Administrative and General Expenses Transferred - Credit		38,059.89
923	Outside Services Employed		982,052.74
924	Property Insurance		727,341.27
925	Injuries and Damages		281,612.44
926	Employee Pensions and Benefits		1,535,405.37
928	Regulatory Commission Expenses		0.00
929	Duplicate Charges - Credit		0.00
930	Miscellaneous General Expenses		187,387.92
931	Rents		1,562.97
935	Maintenance of General Plant		3,583.93
	Total Administrative and General Expenses	$	4,303,401.93
	Total Operation and Maintenance Allocated to Component B	$	14,711,553.56
Deduct Transmission Charge (Account 566.1)			(1,329,653.20)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	13,381,900.36

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 33,773,990.64**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 5,299,139.13
Buckeye	18.00	6,079,318.31
Cincinnati	9.00	3,039,659.16
Columbus	4.44	1,499,565.18
Dayton	4.90	1,654,925.54
Energy Harbor	4.85	1,638,038.55
Indiana	7.85	2,651,258.27
Kentucky	2.50	844,349.77
Louisville	5.63	1,901,475.67
Monongahela	3.50	1,182,089.67
Ohio Power	15.49	5,231,591.15
Peninsula	6.65	2,245,970.38
So. Indiana	1.50	506,609.86
Total	100.00	$ 33,773,990.64

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$**	**1,329,653.20**

Sponsoring Company	PPR		Transmission Charges Payable
Appalachian	15.69	$	208,622.59
Buckeye	18.00		239,337.57
Cincinnati	9.00		119,668.79
Columbus	4.44		59,036.60
Dayton	4.90		65,153.01
Energy Harbor	4.85		64,488.18
Indiana	7.85		104,377.78
Kentucky	2.50		33,241.33
Louisville	5.63		74,859.47
Monongahela	3.50		46,537.86
Ohio Power	15.49		205,963.28
Peninsula	6.65		88,421.94
So. Indiana	1.50		19,944.80
Total	100.00	$	1,329,653.20

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**340,045.69**
Energy Cost of PJM External Power		**(304,788.26)**
Net PJM External Charge/(Credit)	$	**35,257.43**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	6,618.11
Buckeye	19.92		7,594.05
Cincinnati	9.96		3,797.02
Columbus	4.91		1,871.83
Dayton	5.42		2,066.25
Energy Harbor	5.37		2,047.19
Indiana	8.69		3,312.86
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		1,475.35
Ohio Power	17.14		6,534.24
Peninsula	7.36		2,805.83
So. Indiana	0.00		-
Total	100.00	$	38,122.73

September 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 9,318,571.82	$ 0.00	$ 9,318,571.82	$ 8,974,676.00	$ 343,895.82
Buckeye	10,690,531.81	0.00	10,690,531.81	10,295,993.00	394,538.81
Cincinnati	5,345,265.91	0.00	5,345,265.91	5,147,997.00	197,268.91
Columbus	2,636,991.15	0.00	2,636,991.15	2,539,679.00	97,312.15
Dayton	2,910,215.84	0.00	2,910,215.84	2,802,818.00	107,397.84
Energy Harbor	2,880,500.57	0.00	2,880,500.57	2,774,190.00	106,310.57
Indiana	4,662,270.40	0.00	4,662,270.40	4,490,202.00	172,068.40
Kentucky	1,495,333.27	0.00	1,495,333.27	1,443,702.00	51,631.27
Louisville	3,367,546.45	0.00	3,367,546.45	3,251,262.00	116,284.45
Monongahela	2,078,678.16	0.00	2,078,678.16	2,001,968.00	76,710.16
Ohio Power	9,199,801.60	0.00	9,199,801.60	8,860,283.00	339,518.60
Peninsula	3,949,544.23	0.00	3,949,544.23	3,803,785.00	145,759.23
So. Indiana	989,556.71	0.00	989,556.71	951,292.00	38,264.71
PJM Sponsors	(149,324.20)	0.00	(149,324.20)	(137,847.00)	(11,477.20)
Total	$ 59,375,483.72	$ 0.00	$ 59,375,483.72	$ 57,200,000.00	$ 2,175,483.72

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 18,137,679.31	
Fuel Oil Consumed	234,873.68	
Other Fixed Fuel Related Costs*	3,216,992.33	
Total Account 501 (Fuel)		$ 21,589,545.32
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,360,105.93
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 22,949,651.25

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 22,949,651.25

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	**$ 22,949,651.25**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	93,610,000	0.1568997	$ 3,600,793.40
Buckeye	107,392,000	0.1799998	4,130,932.63
Cincinnati	53,696,000	0.0899999	2,065,466.32
Columbus	26,490,000	0.0443999	1,018,962.22
Dayton	29,235,000	0.0490008	1,124,551.27
Energy Harbor	28,936,000	0.0484996	1,113,048.91
Indiana	46,835,000	0.0785002	1,801,552.21
Kentucky	15,300,000	0.0256443	588,527.74
Louisville	34,457,000	0.0577534	1,325,420.39
Monongahela	20,881,000	0.0349986	803,205.66
Ohio Power	92,417,000	0.1549002	3,554,905.57
Peninsula	39,675,000	0.0664993	1,526,135.74
So. Indiana	11,581,000	0.0194109	445,473.39
PJM Sponsors	(3,882,000)	-0.0065066	(149,324.20)
Total	596,623,000	1.0000000	$ 22,949,651.25

Available Power Energy Summary

Available Energy Billed			596,623,000 kWh
Average Available Energy Cost	22,949,651.25 / 596,623,000	=	38.466 mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 18,364,963.99
Available Energy Billed	596,623,000 kWh
Average Fuel Cost from Account 151 (Fuel Stock)	30.782 mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	17,650,663.24
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		14,498,715.70
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		1,011,660.25
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	35,061,939.19

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,275,278.63
2006-A Extended Notes, 6.40%, due June 15, 2040		136,806.36
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,570,255.83
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		101,656.50
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		325,617.33
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		679,984.06
2008-B Extended Notes, 6.91% due June 15, 2040		93,685.00
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		670,450.89
2008-C Extended Notes, 6.91% due June 15, 2040		95,312.85
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,903,592.90

Capital Lease Expense

Capital Lease Expense	$	77,105.08

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,443,382.58
428	Amortization of Debt Discount and Expense		144,198.68
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		821,612.93
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,409,194.19

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,260,771.07
TOTAL COMPONENT A	$	17,650,663.24

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	986,248.46
502	Steam Expenses		670,197.53
505	Electric Expenses		407,229.60
506	Miscellaneous Steam Power Expenses		838,805.58
507	Rents		6,890.00
510	Maintenance of Supervision and Engineering		695,583.73
511	Maintenance of Structures		488,101.63
512	Maintenance of Boiler Plant		6,713,428.65
513	Maintenance of Electric Plant		760,593.82
514	Maintenance of Miscellaneous Steam Plant		117,761.04
556	System Control and Load Dispatching		1,821.64
557	Other Expenses		-
	Total Production Expenses	$	11,686,661.68
Transmission Expenses			
560	Operation Supervision and Engineering	$	33,922.97
561	Load Dispatching		80,379.44
562	Station Expenses		106,287.65
563	Overhead Line Expenses		28,985.34
566	Miscellaneous Transmission Expenses		2,862.80
567	Rents		146.16
568	Maintenance of Supervision and Engineering		-
569	Maintenance of Structures		18,238.33
570	Maintenance of Station Equipment		45,996.66
571	Maintenance of Overhead Lines		212.04
573	Maintenance of Miscellaneous Transmission Plant		-
	Total Transmission Expenses	$	317,031.39
Administrative and General Expenses			
920	Administrative and General Salaries	$	453,280.10
921	Office Supplies and Expenses		141,548.29
922	Administrative and General Expenses Transferred - Credit		(2,337.45)
923	Outside Services Employed		768,493.53
924	Property Insurance		408,189.44
925	Injuries and Damages		276,853.72
926	Employee Pensions and Benefits		1,526,746.32
928	Regulatory Commission Expenses		0.00
929	Duplicate Charges - Credit		(363.86)
930	Miscellaneous General Expenses		130,458.41
931	Rents		288.81
935	Maintenance of General Plant		2,147.32
	Total Administrative and General Expenses	$	3,705,304.63
	Total Operation and Maintenance Allocated to Component B	$	15,708,997.70
Deduct Transmission Charge (Account 566.1)			(1,210,282.00)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	14,498,715.70

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 35,061,939.19**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 5,501,218.26
Buckeye	18.00	6,311,149.05
Cincinnati	9.00	3,155,574.53
Columbus	4.44	1,556,750.10
Dayton	4.90	1,718,035.02
Energy Harbor	4.85	1,700,504.05
Indiana	7.85	2,752,362.23
Kentucky	2.50	876,548.48
Louisville	5.63	1,973,987.18
Monongahela	3.50	1,227,167.87
Ohio Power	15.49	5,431,094.38
Peninsula	6.65	2,331,618.95
So. Indiana	1.50	525,929.09
Total	100.00	$ 35,061,939.19

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$ 1,210,282.00**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 189,893.24
Buckeye	18.00	217,850.76
Cincinnati	9.00	108,925.38
Columbus	4.44	53,736.52
Dayton	4.90	59,303.82
Energy Harbor	4.85	58,698.68
Indiana	7.85	95,007.14
Kentucky	2.50	30,257.05
Louisville	5.63	68,138.88
Monongahela	3.50	42,359.87
Ohio Power	15.49	187,472.68
Peninsula	6.65	80,483.75
So. Indiana	1.50	18,154.23
Total	100.00	$ 1,210,282.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**300,070.18**
Energy Cost of PJM External Power		**(149,324.20)**
Net PJM External Charge/(Credit)	$	**150,745.98**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR	PJM Demand Expenses & Fees Payable
Appalachian	17.36	$ 26,666.92
Buckeye	19.92	30,599.37
Cincinnati	9.96	15,299.68
Columbus	4.91	7,542.31
Dayton	5.42	8,325.73
Energy Harbor	5.37	8,248.93
Indiana	8.69	13,348.82
Kentucky	0.00	-
Louisville	0.00	-
Monongahela	3.87	5,944.76
Ohio Power	17.14	26,328.97
Peninsula	7.36	11,305.79
So. Indiana	0.00	-
Total	100.00	$ 153,611.28

October 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,529,158.83	$ 0.00	$ 10,529,158.83	$ 10,731,965.00	$ (202,806.17)
Buckeye	12,079,354.23	0.00	12,079,354.23	12,312,018.00	(232,663.77)
Cincinnati	6,039,658.30	0.00	6,039,658.30	6,155,987.00	(116,328.70)
Columbus	2,979,569.83	0.00	2,979,569.83	3,036,963.00	(57,393.17)
Dayton	3,288,267.46	0.00	3,288,267.46	3,351,607.00	(63,339.54)
Energy Harbor	3,254,712.71	0.00	3,254,712.71	3,317,402.00	(62,689.29)
Indiana	5,267,933.04	0.00	5,267,933.04	5,369,396.00	(101,462.96)
Kentucky	1,689,610.51	0.00	1,689,610.51	1,724,714.00	(35,103.49)
Louisville	3,804,940.92	0.00	3,804,940.92	3,883,995.00	(79,054.08)
Monongahela	2,348,741.35	0.00	2,348,741.35	2,393,983.00	(45,241.65)
Ohio Power	10,394,923.55	0.00	10,394,923.55	10,595,142.00	(200,218.45)
Peninsula	4,462,642.21	0.00	4,462,642.21	4,548,599.00	(85,956.79)
So. Indiana	1,108,327.23	0.00	1,108,327.23	1,130,704.00	(22,376.77)
PJM Sponsors	(149,094.94)	0.00	(149,094.94)	(152,475.00)	3,380.06
Total	$ 67,098,745.23	$ 0.00	$ 67,098,745.23	$ 68,400,000.00	$ (1,301,254.77)

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 22,555,970.59	
Fuel Oil Consumed	492,619.06	
Other Fixed Fuel Related Costs*	2,304,057.72	
Total Account 501 (Fuel)		$ 25,352,647.37
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,510,336.84
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 26,862,984.21

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 26,862,984.21

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	$ **26,862,984.21**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	115,113,000	0.1569002	$ 4,214,807.60
Buckeye	132,061,000	0.1800006	4,835,353.28
Cincinnati	66,030,000	0.0899996	2,417,657.83
Columbus	32,575,000	0.0444001	1,192,719.19
Dayton	35,950,000	0.0490002	1,316,291.60
Energy Harbor	35,583,000	0.0485000	1,302,854.73
Indiana	57,593,000	0.0784999	2,108,741.57
Kentucky	18,729,000	0.0255278	685,752.89
Louisville	42,176,000	0.0574863	1,544,253.57
Monongahela	25,678,000	0.0349994	940,188.33
Ohio Power	113,645,000	0.1548994	4,161,060.14
Peninsula	48,789,000	0.0664999	1,786,385.76
So. Indiana	13,820,000	0.0188368	506,012.66
PJM Sponsors	(4,072,000)	-0.0055502	(149,094.94)
Total	733,670,000	1.0000000	$ 26,862,984.21

Available Power Energy Summary

Available Energy Billed			733,670,000 kWh
Average Available Energy Cost	26,862,984.21 / 733,670,000	=	36.615 mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 23,048,589.65
Available Energy Billed	733,670,000 kWh
Average Fuel Cost from Account 151 (Fuel Stock)	31.416 mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	18,907,473.07
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		17,069,552.50
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		1,011,202.27
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	38,889,127.84

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,275,278.63
2006-A Extended Notes, 6.40%, due June 15, 2040		136,806.36
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,570,255.83
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		101,656.50
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		325,617.33
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		702,797.51
2008-B Extended Notes, 6.91% due June 15, 2040		203,747.17
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		692,944.52
2008-C Extended Notes, 6.91% due June 15, 2040		98,605.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		9,062,255.13

Capital Lease Expense	$	77,406.26

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,284,387.77
428	Amortization of Debt Discount and Expense		144,198.68
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		903,226.60
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,331,813.05

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	5,435,998.63

TOTAL COMPONENT A	$	18,907,473.07

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	1,053,335.53
502	Steam Expenses		859,545.38
505	Electric Expenses		323,089.58
506	Miscellaneous Steam Power Expenses		995,492.28
507	Rents		13,780.00
510	Maintenance of Supervision and Engineering		742,662.63
511	Maintenance of Structures		1,308,317.28
512	Maintenance of Boiler Plant		8,054,508.49
513	Maintenance of Electric Plant		887,834.65
514	Maintenance of Miscellaneous Steam Plant		232,958.62
556	System Control and Load Dispatching		1,541.10
557	Other Expenses		-
	Total Production Expenses	$	14,473,065.54
Transmission Expenses			
560	Operation Supervision and Engineering	$	36,621.71
561	Load Dispatching		49,148.30
562	Station Expenses		60,406.05
563	Overhead Line Expenses		70,616.81
566	Miscellaneous Transmission Expenses		8,920.08
567	Rents		-
568	Maintenance of Supervision and Engineering		-
569	Maintenance of Structures		20,556.67
570	Maintenance of Station Equipment		67,676.30
571	Maintenance of Overhead Lines		181.77
573	Maintenance of Miscellaneous Transmission Plant		3,502.32
	Total Transmission Expenses	$	317,630.01
Administrative and General Expenses			
920	Administrative and General Salaries	$	480,265.20
921	Office Supplies and Expenses		96,292.14
922	Administrative and General Expenses Transferred - Credit		0.00
923	Outside Services Employed		564,752.54
924	Property Insurance		421,795.72
925	Injuries and Damages		279,216.47
926	Employee Pensions and Benefits		1,547,607.29
928	Regulatory Commission Expenses		1,873.17
929	Duplicate Charges - Credit		(773.21)
930	Miscellaneous General Expenses		72,780.35
931	Rents		1,851.79
935	Maintenance of General Plant		78,372.29
	Total Administrative and General Expenses	$	3,544,033.75
	Total Operation and Maintenance Allocated to Component B	$	18,334,729.30
Deduct Transmission Charge (Account 566.1)			(1,265,176.80)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	17,069,552.50

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	$	**38,889,127.84**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 6,101,704.16
Buckeye	18.00	7,000,043.01
Cincinnati	9.00	3,500,021.51
Columbus	4.44	1,726,677.28
Dayton	4.90	1,905,567.26
Energy Harbor	4.85	1,886,122.70
Indiana	7.85	3,052,796.53
Kentucky	2.50	972,228.20
Louisville	5.63	2,189,457.90
Monongahela	3.50	1,361,119.47
Ohio Power	15.49	6,023,925.90
Peninsula	6.65	2,586,127.00
So. Indiana	1.50	583,336.92
Total	100.00	$ 38,889,127.84

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$ 1,265,176.80**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 198,506.24
Buckeye	18.00	227,731.83
Cincinnati	9.00	113,865.91
Columbus	4.44	56,173.85
Dayton	4.90	61,993.66
Energy Harbor	4.85	61,361.07
Indiana	7.85	99,316.38
Kentucky	2.50	31,629.42
Louisville	5.63	71,229.45
Monongahela	3.50	44,281.19
Ohio Power	15.49	195,975.89
Peninsula	6.65	84,134.26
So. Indiana	1.50	18,977.65
Total	100.00	$ 1,265,176.80

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**227,686.02**
Energy Cost of PJM External Power		**(149,094.94)**
Net PJM External Charge/(Credit)	$	**78,591.08**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR	PJM Demand Expenses & Fees Payable
Appalachian	17.36	$ 14,140.83
Buckeye	19.92	16,226.11
Cincinnati	9.96	8,113.05
Columbus	4.91	3,999.51
Dayton	5.42	4,414.94
Energy Harbor	5.37	4,374.21
Indiana	8.69	7,078.56
Kentucky	0.00	-
Louisville	0.00	-
Monongahela	3.87	3,152.36
Ohio Power	17.14	13,961.62
Peninsula	7.36	5,995.19
So. Indiana	0.00	-
Total	100.00	$ 81,456.38

November 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 10,557,939.96	$ 0.00	$ 10,557,939.96	$ 10,731,966.00	$ (174,026.04)
Buckeye	12,112,350.56	0.00	12,112,350.56	12,311,992.00	(199,641.44)
Cincinnati	6,056,175.27	0.00	6,056,175.27	6,155,997.00	(99,821.73)
Columbus	2,987,720.07	0.00	2,987,720.07	3,036,972.00	(49,251.93)
Dayton	3,297,243.22	0.00	3,297,243.22	3,351,593.00	(54,349.78)
Energy Harbor	3,263,626.35	0.00	3,263,626.35	3,317,416.00	(53,789.65)
Indiana	5,282,327.01	0.00	5,282,327.01	5,369,390.00	(87,062.99)
Kentucky	1,681,883.87	0.00	1,681,883.87	1,711,292.00	(29,408.13)
Louisville	3,787,725.13	0.00	3,787,725.13	3,853,956.00	(66,230.87)
Monongahela	2,355,170.24	0.00	2,355,170.24	2,393,993.00	(38,822.76)
Ohio Power	10,423,347.02	0.00	10,423,347.02	10,595,151.00	(171,803.98)
Peninsula	4,474,850.14	0.00	4,474,850.14	4,548,608.00	(73,757.86)
So. Indiana	1,215,248.77	0.00	1,215,248.77	1,238,637.00	(23,388.23)
PJM Sponsors	(217,233.44)	0.00	(217,233.44)	(216,963.00)	(270.44)
Total	$ 67,278,374.17	$ 0.00	$ 67,278,374.17	$ 68,400,000.00	$ (1,121,625.83)

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 28,744,324.22	
Fuel Oil Consumed	250,831.47	
Other Fixed Fuel Related Costs*	1,330,406.27	
Total Account 501 (Fuel)		$ 30,325,561.96
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,559,107.47
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 31,884,669.43

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 31,884,669.43

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	$ **31,884,669.43**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	148,630,000	0.1569002	$ 5,002,711.01
Buckeye	170,512,000	0.1799998	5,739,234.12
Cincinnati	85,256,000	0.0899999	2,869,617.06
Columbus	42,060,000	0.0444003	1,415,688.89
Dayton	46,417,000	0.0489998	1,562,342.43
Energy Harbor	45,944,000	0.0485005	1,546,422.41
Indiana	74,362,000	0.0784997	2,502,936.99
Kentucky	23,767,000	0.0250895	799,970.41
Louisville	53,527,000	0.0565054	1,801,656.00
Monongahela	33,155,000	0.0349998	1,115,957.05
Ohio Power	146,735,000	0.1548998	4,938,928.92
Peninsula	62,995,000	0.0665002	2,120,336.89
So. Indiana	20,384,000	0.0215182	686,100.69
PJM Sponsors	(6,454,000)	-0.0068131	(217,233.44)
Total	947,290,000	1.0000000	$ 31,884,669.43

Available Power Energy Summary

Available Energy Billed			947,290,000	kWh
Average Available Energy Cost	31,884,669.43 / 947,290,000	=	33.659	mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 28,995,155.69	
Available Energy Billed	947,290,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)	30.609	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A		
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	16,946,691.68
COMPONENT B		
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		12,605,133.21
COMPONENT C		
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		2,472,236.13
COMPONENT D		
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00
COMPONENT E		
Post Retirement Benefit Obligations (Account 926.22)		-
COMPONENT F		
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00
Total Demand Charge	$	33,924,961.02

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,275,278.63
2006-A Extended Notes, 6.40%, due June 15, 2040		136,806.36
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,570,255.85
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		101,656.50
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		325,617.33
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		702,797.51
2008-B Extended Notes, 6.91% due June 15, 2040		96,921.83
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		692,944.52
2008-C Extended Notes, 6.91% due June 15, 2040		98,605.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		8,955,429.81

Capital Lease Expense	$	77,708.72

Interest and Debt Expense

427	Interest on Long-Term Debt	$	3,391,213.13
428	Amortization of Debt Discount and Expense		144,198.68
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		848,125.97
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	4,383,537.78

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	3,530,015.37
TOTAL COMPONENT A	$	16,946,691.68

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses		
500	Operation, Supervision, and Engineering	$ 1,046,258.42
502	Steam Expenses	646,268.17
505	Electric Expenses	326,590.15
506	Miscellaneous Steam Power Expenses	866,848.25
507	Rents	-
510	Maintenance of Supervision and Engineering	631,787.12
511	Maintenance of Structures	850,257.36
512	Maintenance of Boiler Plant	3,888,321.50
513	Maintenance of Electric Plant	493,080.16
514	Maintenance of Miscellaneous Steam Plant	160,392.90
556	System Control and Load Dispatching	(158.91)
557	Other Expenses	-
	Total Production Expenses	$ 8,909,645.12
Transmission Expenses		
560	Operation Supervision and Engineering	$ 43,958.72
561	Load Dispatching	73,325.90
562	Station Expenses	73,548.60
563	Overhead Line Expenses	159,748.66
566	Miscellaneous Transmission Expenses	5,548.84
567	Rents	155.83
568	Maintenance of Supervision and Engineering	-
569	Maintenance of Structures	17,148.67
570	Maintenance of Station Equipment	209,824.03
571	Maintenance of Overhead Lines	236.76
573	Maintenance of Miscellaneous Transmission Plant	1,662.55
	Total Transmission Expenses	$ 585,158.56
Administrative and General Expenses		
920	Administrative and General Salaries	$ 508,373.89
921	Office Supplies and Expenses	157,131.01
922	Administrative and General Expenses Transferred - Credit	2,780.39
923	Outside Services Employed	976,554.53
924	Property Insurance	408,189.45
925	Injuries and Damages	282,927.00
926	Employee Pensions and Benefits	1,950,341.49
928	Regulatory Commission Expenses	10,327.68
929	Duplicate Charges - Credit	432.09
930	Miscellaneous General Expenses	155,787.66
931	Rents	358.17
935	Maintenance of General Plant	8,703.77
	Total Administrative and General Expenses	$ 4,461,907.13
	Total Operation and Maintenance Allocated to Component B	$ 13,956,710.81
Deduct Transmission Charge (Account 566.1)		(1,351,577.60)
Deduct Minimum Loading Event Charges - non-fuel		
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties		
	TOTAL COMPONENT B	$ 12,605,133.21

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Section 5.03
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Demand Charge	**$ 33,924,961.02**

Sponsoring Company	PPR	Total Demand Charge Payable
Appalachian	15.69	$ 5,322,826.38
Buckeye	18.00	6,106,492.98
Cincinnati	9.00	3,053,246.49
Columbus	4.44	1,506,268.27
Dayton	4.90	1,662,323.09
Energy Harbor	4.85	1,645,360.61
Indiana	7.85	2,663,109.44
Kentucky	2.50	848,124.02
Louisville	5.63	1,909,975.31
Monongahela	3.50	1,187,373.64
Ohio Power	15.49	5,254,976.46
Peninsula	6.65	2,256,009.91
So. Indiana	1.50	508,874.42
Total	100.00	$ 33,924,961.02

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5.04
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Transmission Charge	**$ 1,351,577.60**

Sponsoring Company	PPR	Transmission Charges Payable
Appalachian	15.69	$ 212,062.53
Buckeye	18.00	243,283.97
Cincinnati	9.00	121,641.98
Columbus	4.44	60,010.05
Dayton	4.90	66,227.30
Energy Harbor	4.85	65,551.51
Indiana	7.85	106,098.84
Kentucky	2.50	33,789.44
Louisville	5.63	76,093.82
Monongahela	3.50	47,305.22
Ohio Power	15.49	209,359.37
Peninsula	6.65	89,879.91
So. Indiana	1.50	20,273.66
Total	100.00	$ 1,351,577.60

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursuant to Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreement

OVEC PJM External Account Net Settlements	$	**331,534.26**
Energy Cost of PJM External Power		**(217,233.44)**
Net PJM External Charge/(Credit)	$	**114,300.82**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR		PJM Demand Expenses & Fees Payable
Appalachian	17.36	$	20,340.04
Buckeye	19.92		23,339.49
Cincinnati	9.96		11,669.74
Columbus	4.91		5,752.86
Dayton	5.42		6,350.40
Energy Harbor	5.37		6,291.82
Indiana	8.69		10,181.74
Kentucky	0.00		-
Louisville	0.00		-
Monongahela	3.87		4,534.33
Ohio Power	17.14		20,082.27
Peninsula	7.36		8,623.43
So. Indiana	0.00		-
Total	100.00	$	117,166.12

December 2023
Summary

Ohio Valley Electric Corporation
Available Power Statement

Sum of Energy, Demand and Transmission Charges Payable for Available Power
Pursuant to the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Total Energy, Demand, PJM, and Transmission Charges	Minimum Loading Event Charges	Total Monthly Charge	Less Provisional Semimonthly Payments	Net Amount Payable
Appalachian	$ 12,813,887.57	$ 0.00	$ 12,813,887.57	$ 12,081,292.00	$ 732,595.57
Buckeye	14,700,461.62	0.00	14,700,461.62	13,860,001.00	840,460.62
Cincinnati	7,350,212.98	0.00	7,350,212.98	6,929,981.00	420,231.98
Columbus	3,626,097.59	0.00	3,626,097.59	3,418,788.00	207,309.59
Dayton	4,001,800.60	0.00	4,001,800.60	3,773,010.00	228,790.60
Energy Harbor	3,960,951.26	0.00	3,960,951.26	3,734,490.00	226,461.26
Indiana	6,411,035.46	0.00	6,411,035.46	6,044,498.00	366,537.46
Kentucky	2,069,675.59	0.00	2,069,675.59	1,954,162.00	115,513.59
Louisville	4,660,919.58	0.00	4,660,919.58	4,400,774.00	260,145.58
Monongahela	2,858,427.06	0.00	2,858,427.06	2,695,008.00	163,419.06
Ohio Power	12,650,550.42	0.00	12,650,550.42	11,927,293.00	723,257.42
Peninsula	5,430,999.09	0.00	5,430,999.09	5,120,495.00	310,504.09
So. Indiana	1,395,960.25	0.00	1,395,960.25	1,316,862.00	79,098.25
PJM Sponsors	(271,914.79)	0.00	(271,914.79)	(256,654.00)	(15,260.79)
Total	$ 81,659,064.28	$ 0.00	$ 81,659,064.28	$ 77,000,000.00	$ 4,659,064.28

Wire transfer to:

KeyBank, N.A.
ABA: 041001039 Bank Acct: 359681133203
Re: Ohio Valley Electric Corporation

Payment Terms:

Section 8.01 and 8.02 of the Inter-Company Power Agreement, dated September 10, 2010 as modified, state in part:

"Sponsoring Company shall make payment therefor promptly upon receipt of such statement (Provisional or Monthly), but in no event later than fifteen (15) days after the date of receipt of such statement."

Ohio Valley Electric Corporation
Available Power Statement

Determination of Power Participation Ratio (PPR) Pursuant to the
Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	PPR
Appalachian	15.69
Buckeye	18.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
Energy Harbor	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Peninsula	6.65
So. Indiana	1.50
Total	100.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of Project Generating Stations Energy Charge for Available Energy Pursuant to Secti
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Project Generating Stations Fuel Costs

Account 501 (Fuel):		
Coal Consumed	$ 31,799,747.27	
Fuel Oil Consumed	280,692.07	
Other Fixed Fuel Related Costs*	5,554,750.62	
Total Account 501 (Fuel)		$ 37,635,189.96
Account 506.5 (Variable Reagent Costs Associated with Pollution Control Facilities)		1,971,934.99
Account 509 (Allowances)		0.00
Total Fuel Cost		$ 39,607,124.95

Deduct Minimum Loading Event Costs - Fuel

Account 509 (Allowances) costs from Table 1**	$ 0.00
Account 501 (Fuel) costs from Table 2**	0.00
Total Minimum Loading Event Costs - Fuel	$ 0.00

Total Energy Charge	$ 39,607,124.95

* Other Fixed Fuel Related Costs include labor, employee benefits, ash and gypsum disposal, and various other fuel related costs.

** Tables from Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, adopted by the Operating Committee effective June 2, 2010

Ohio Valley Electric Corporation
Available Power Statement

Determination of Energy Charge Payable by Sponsoring Companies Pursuant to Section 5.02
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Amended

Total Energy Charge	$	**39,607,124.95**

Sponsoring Company	Available Energy (Billing kWh)	Available Energy Allocation Ratio	Total Energy Charge Payable
Appalachian	163,018,000	0.1568998	$ 6,214,349.98
Buckeye	187,019,000	0.1800001	7,129,286.45
Cincinnati	93,509,000	0.0899996	3,564,625.40
Columbus	46,131,000	0.0443997	1,758,544.47
Dayton	50,911,000	0.0490003	1,940,761.01
Energy Harbor	50,391,000	0.0484998	1,920,937.64
Indiana	81,561,000	0.0785000	3,109,159.31
Kentucky	26,777,000	0.0257720	1,020,754.82
Louisville	60,302,000	0.0580388	2,298,750.00
Monongahela	36,365,000	0.0350002	1,386,257.29
Ohio Power	160,940,000	0.1548998	6,135,135.73
Peninsula	69,093,000	0.0664999	2,633,869.85
So. Indiana	20,110,000	0.0193553	766,607.79
PJM Sponsors	(7,133,000)	-0.0068653	(271,914.79)
Total	1,038,994,000	1.0000000	$ 39,607,124.95

Available Power Energy Summary

Available Energy Billed			1,038,994,000	kWh
Average Available Energy Cost	39,607,124.95 / 1,038,994,000	=	38.121	mills/kWh

Average Fuel Cost from Account 151 (Fuel Stock)	$ 32,080,439.34	
Available Energy Billed	1,038,994,000	kWh
Average Fuel Cost from Account 151 (Fuel Stock)	30.876	mills/kWh

Ohio Valley Electric Corporation
Available Power Statement

Determination of Demand Charges of Corporation applicable to the Ownership, Operation and Maintenance of the Project Generating Stations and Project Transmission Facilities Pursuant to Section 5.03, and Article 7 of the Amended and Restated Inter-Company Power Agreement Dated September 10, 2010, as Amended

COMPONENT A			
Debt amortization, interest and debt expense applicable to the retirement of indebtedness of Corporation and an allowance for depreciation for additional facilities and replacements (See Exhibit A).	$	16,933,436.86	Macro Lookup
COMPONENT B			
Total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expenses, etc., properly chargeable to Operation and Maintenance Expense Accounts (See Exhibit B).		19,094,075.49	
COMPONENT C			
Total expenses for taxes not included in Components A, B, or D (Accounts 408, 409, 410 and 411).		2,637,811.49	DEMANDC
COMPONENT D			
An amount equal to the product of $2.089 multiplied by 100,000 outstanding shares of the Corporation's capital stock at the par value of $100 per share.		208,900.00	fixed at $208,900/month
COMPONENT E			
Post Retirement Benefit Obligations (Account 926.22)		2,076.34	DEMANDE
COMPONENT F			
Decommissioning and Demolition Obligations (Account 403.15)		1,692,000.00	DEMANDF
Total Demand Charge	$	40,568,300.18	

Ohio Valley Electric Corporation
Available Power Statement

Exhibit A

Schedule of Debt Amortization, Interest and Debt Expense applicable
to the Retirement of Indebtedness of Corporation and an Allowance for
Depreciation for Additional Facilities and Replacements
(Account References are from the Federal Energy Regulatory Commission
Uniform System of Accounts Effective as of January 1, 2004)

Debt Amortization

$445 Million 5.80% Senior Notes, Series 2006-A Notes, due February 15, 2026	$	2,275,278.63
2006-A Extended Notes, 6.40%, due June 15, 2040		136,806.36
$300 Million 5.90% Senior Notes, Series 2007-A, B & C Notes, due February 15, 2026		1,616,578.33
2007-A, B & C Extended Notes, 6.50%, due June 15, 2040		104,960.33
$50 Million 5.92% Senior Notes, Series 2008-A Notes, due February 15, 2026		335,255.50
$150 Million 6.71% Senior Notes, Series 2008-B Notes, due February 15, 2026		702,797.51
2008-B Extended Notes, 6.91% due June 15, 2040		96,921.83
$150 Million 6.71% Senior Notes, Series 2008-C Notes, due February 15, 2026		692,944.52
2008-C Extended Notes, 6.91% due June 15, 2040		98,605.83
$100 Million Floating Rate Senior Notes, Series 2017-A, due September 6, 2022		2,954,545.45
Total Debt Amortization		9,014,694.29

Capital Lease Expense	$	78,012.56

Interest and Debt Expense

427	Interest on Long-Term Debt	$	2,495,282.03
428	Amortization of Debt Discount and Expense		144,198.68
428	Amortization of Loss on Reacquired Debt		-
429	Amortization of Premium on Debt		-
429	Amortization of Gain on Reacquired Debt		-
430	Interest on Debt to Associated Companies		-
431	Other Interest Expense		846,674.55
432	Allowance for Borrowed Funds Used During Construction - Credit		-
	Total Interest and Debt Expense	$	3,486,155.26

Additional Facilities and Replacements

Allowance for Depreciation of Additional Facilities and Replacements as defined in Sections 7.01 (Replacement Costs) and 7.02 (Additional Facility Costs) of the Amended and Restated Inter-Company Power Agreement dated March 31, 2006, as amended	$	4,354,574.75
TOTAL COMPONENT A	$	16,933,436.86

Ohio Valley Electric Corporation
Available Power Statement

Exhibit B

Schedule of Operating Expenses for Labor, Maintenance,
Materials, Supplies, Services, Insurance, Administrative and General Expenses etc., Properly
Chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts
(Effective as of January 1, 2004) Prescribed by the Federal Energy Regulatory Commission
Exclusive of Accounts 501, 509, 555, 557.1, 566.1, 911, 912, 913, 916, 917 and 926.22

Production Expenses			
500	Operation, Supervision, and Engineering	$	1,121,105.50
502	Steam Expenses		1,000,018.99
505	Electric Expenses		479,335.52
506	Miscellaneous Steam Power Expenses		1,277,457.16
507	Rents		13,780.00
510	Maintenance of Supervision and Engineering		832,475.72
511	Maintenance of Structures		888,666.11
512	Maintenance of Boiler Plant		7,509,612.58
513	Maintenance of Electric Plant		1,641,200.75
514	Maintenance of Miscellaneous Steam Plant		375,946.14
556	System Control and Load Dispatching		615.81
557	Other Expenses		-
	Total Production Expenses	$	15,140,214.28
Transmission Expenses			
560	Operation Supervision and Engineering	$	66,597.35
561	Load Dispatching		64,167.69
562	Station Expenses		176,906.41
563	Overhead Line Expenses		14,537.12
566	Miscellaneous Transmission Expenses		17,281.11
567	Rents		(448.15)
568	Maintenance of Supervision and Engineering		167.04
569	Maintenance of Structures		25,368.26
570	Maintenance of Station Equipment		45,035.75
571	Maintenance of Overhead Lines		464.88
573	Maintenance of Miscellaneous Transmission Plant		4,497.37
	Total Transmission Expenses	$	414,574.83
Administrative and General Expenses			
920	Administrative and General Salaries	$	588,035.00
921	Office Supplies and Expenses		258,800.97
922	Administrative and General Expenses Transferred - Credit		109,269.30
923	Outside Services Employed		2,142,857.51
924	Property Insurance		421,795.74
925	Injuries and Damages		362,747.89
926	Employee Pensions and Benefits		774,087.06
928	Regulatory Commission Expenses		0.00
929	Duplicate Charges - Credit		31,853.06
930	Miscellaneous General Expenses		230,921.94
931	Rents		(69.37)
935	Maintenance of General Plant		7,518.07
	Total Administrative and General Expenses	$	4,927,817.17
	Total Operation and Maintenance Allocated to Component B	$	20,482,606.28
Deduct Transmission Charge (Account 566.1)			(1,388,530.79)
Deduct Minimum Loading Event Charges - non-fuel			
Add Emission of Pollutant or Discharge of Wastes Fines or Penalties			
	TOTAL COMPONENT B	$	19,094,075.49

Ohio Valley Electric Corporation
Available Power Statement

Determination Of Demand Charge Payable by the Sponsoring Companies Pursuant to Sectior
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as /

Total Demand Charge	$	**40,568,300.17**

Sponsoring Company	PPR		Total Demand Charge Payable
Appalachian	15.69	$	6,365,166.30
Buckeye	18.00		7,302,294.03
Cincinnati	9.00		3,651,147.02
Columbus	4.44		1,801,232.53
Dayton	4.90		1,987,846.71
Energy Harbor	4.85		1,967,562.56
Indiana	7.85		3,184,611.56
Kentucky	2.50		1,014,207.50
Louisville	5.63		2,283,995.30
Monongahela	3.50		1,419,890.50
Ohio Power	15.49		6,284,029.70
Peninsula	6.65		2,697,791.96
So. Indiana	1.50		608,524.50
Total	100.00	$	40,568,300.17

Ohio Valley Electric Corporation
Available Power Statement

Determination of Transmission Charge Payable by Sponsoring Companies Pursuant to Section 5
of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010, as Am

Total Transmission Charge	**$**	**1,388,530.80**

Sponsoring Company	PPR		Transmission Charges Payable
Appalachian	15.69	$	217,860.48
Buckeye	18.00		249,935.55
Cincinnati	9.00		124,967.77
Columbus	4.44		61,650.77
Dayton	4.90		68,038.01
Energy Harbor	4.85		67,343.74
Indiana	7.85		108,999.67
Kentucky	2.50		34,713.27
Louisville	5.63		78,174.28
Monongahela	3.50		48,598.58
Ohio Power	15.49		215,083.42
Peninsula	6.65		92,337.30
So. Indiana	1.50		20,827.96
Total	100.00	$	1,388,530.80

Ohio Valley Electric Corporation
Available Power Statement

Determination of Minimum Loading Event Costs Payable by the Sponsoring Companies Pursuant to Section 5.05 of the Amended and Restated Inter-Company Power Agreement dated September 10, 2010

Sponsoring Company	Summary of Events 1	2	3	4	5	6	Minimum Loading Event Costs Payable
Appalachian	$	$	$	$	$	$	$ 0.00
Buckeye							0.00
Cincinnati							0.00
Columbus							0.00
Dayton							0.00
Energy Harbor							0.00
Indiana							0.00
Kentucky							0.00
Louisville							0.00
Monongahela							0.00
Ohio Power							0.00
Peninsula							0.00
So. Indiana							0.00
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00

Ohio Valley Electric Corporation
Available Power Statement

Determination of PJM Credits, Expenses and Fees Payable by PJM Sponsoring Companies Pursu
Section D and E.1.B of the Operating Procedures Under the Inter-Company Power Agreemen

OVEC PJM External Account Net Settlements	$	**364,157.85**
Energy Cost of PJM External Power		**(271,914.79)**
Net PJM External Charge/(Credit)	$	**92,243.06**

PJM Expenses and Fees	**$**	**2,865.30**

Sponsoring Company	PJM PPR	PJM Demand Expense & Fees Payable
Appalachian	17.36	$ 16,510.81
Buckeye	19.92	18,945.59
Cincinnati	9.96	9,472.79
Columbus	4.91	4,669.82
Dayton	5.42	5,154.87
Energy Harbor	5.37	5,107.32
Indiana	8.69	8,264.92
Kentucky	0.00	-
Louisville	0.00	-
Monongahela	3.87	3,680.69
Ohio Power	17.14	16,301.57
Peninsula	7.36	6,999.98
So. Indiana	0.00	-
Total	100.00	$ 95,108.36

AEP GENERATING COMPANY
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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

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT CUB-7C

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

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Executive Summary

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

Background

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

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

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

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

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

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

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

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

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

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

Gross Avoidable Costs for Existing Generation

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January 9, 2023

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pjm

NOTICE

- This report was prepared for PJM Interconnection, L.L.C., in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
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TABLE OF CONTENTS

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.

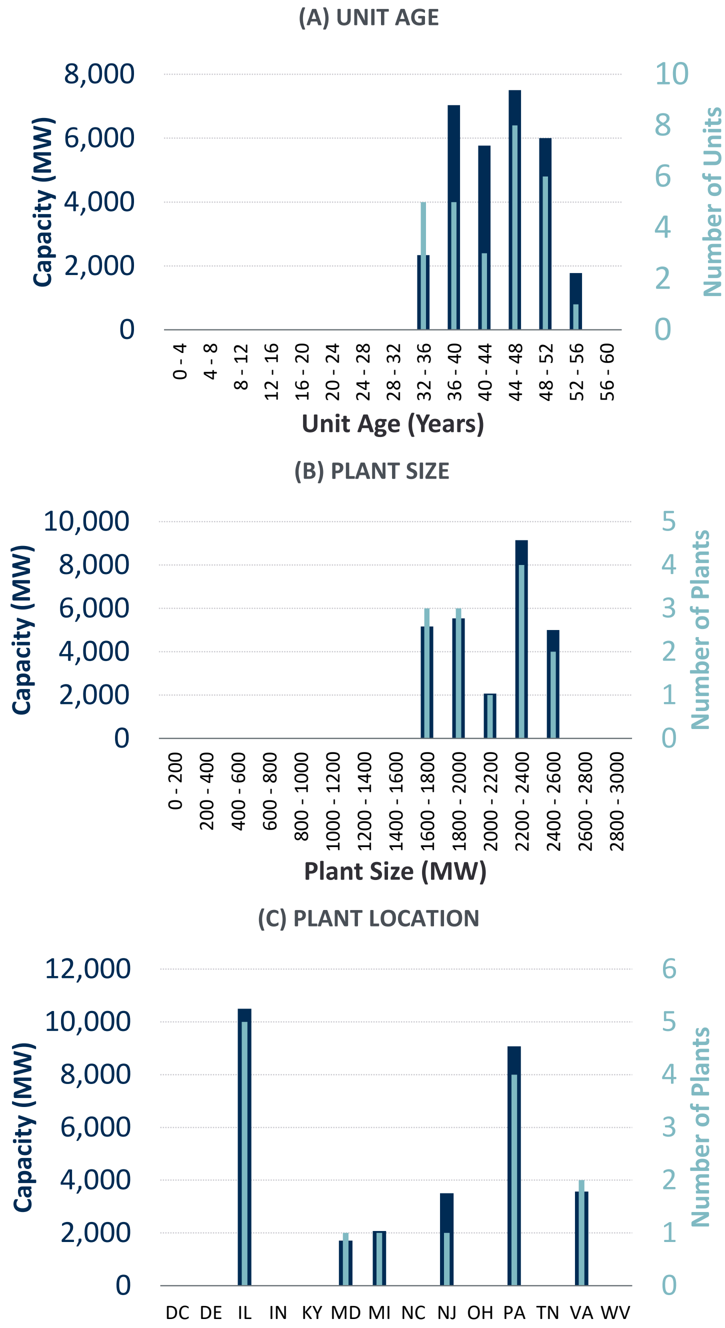
Based on our experience estimating costs for nuclear plants, the most significant cost drivers for nuclear plants are the plant size and number of units, reactor type such as the boiling water reactor (BWR) versus the pressurized water reactor (PWR), the location (which impacts property taxes and operating 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



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

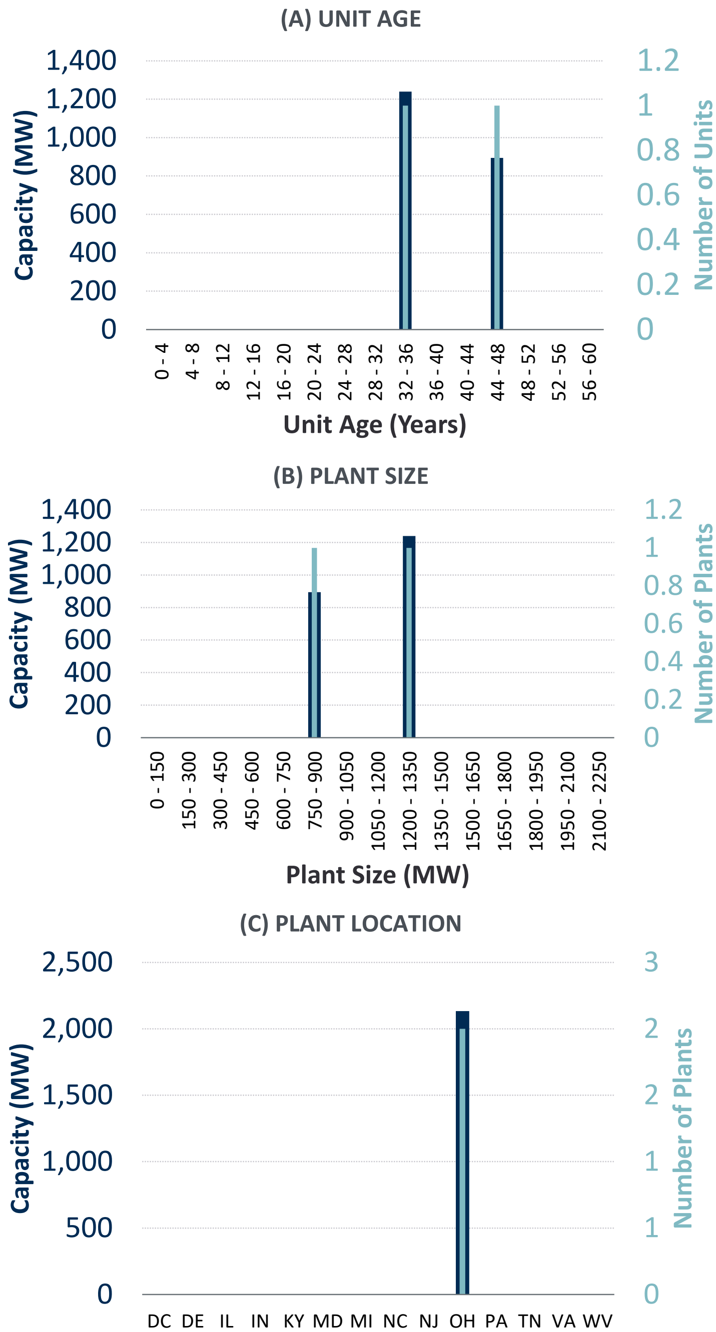
There are currently only two single-unit nuclear plants in the PJM market: the 894 MW Davis Besse plant and 1,240 MW Perry plant in Ohio.[18] Due to the small number of plants and the limited variation among them, we specified a single representative plant to be a 38-year-old 1,200 MW Boiling Water Reactor (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.

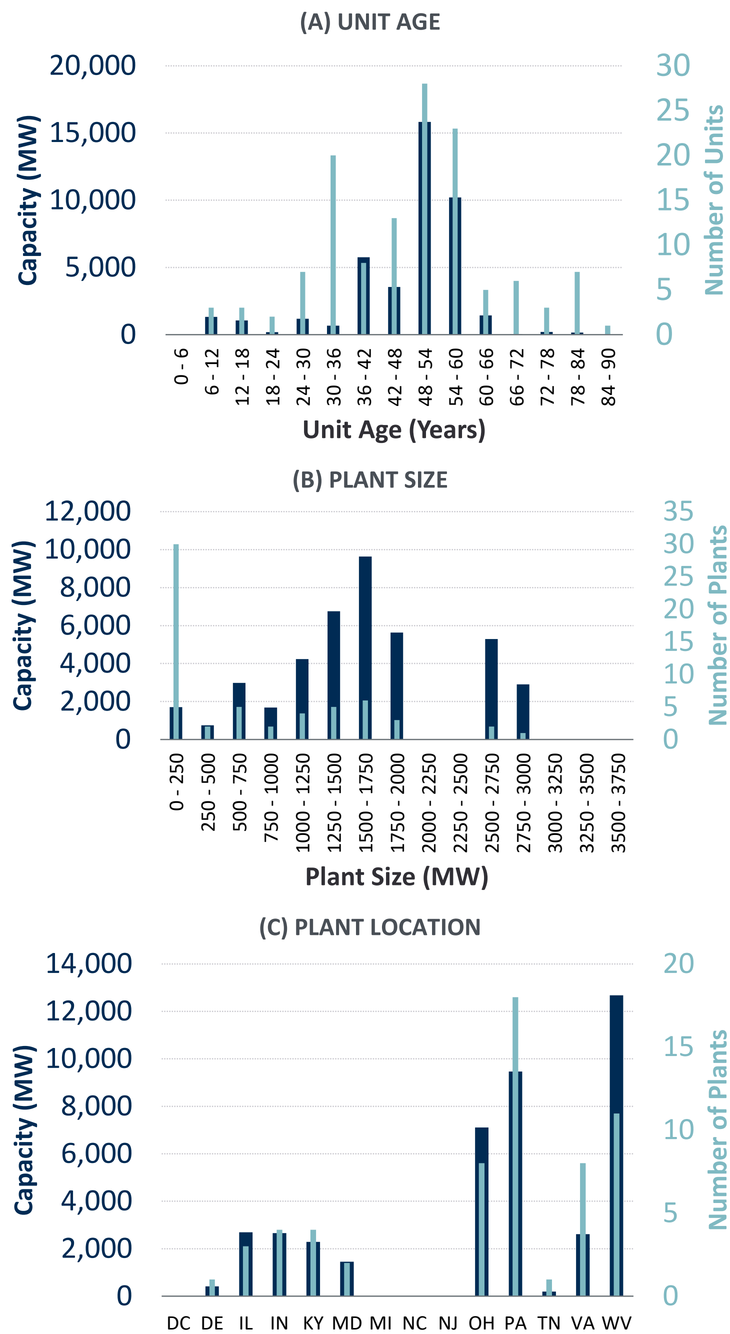
configuration, and technology), followed by the location and the types of post-combustion controls installed at the plant.

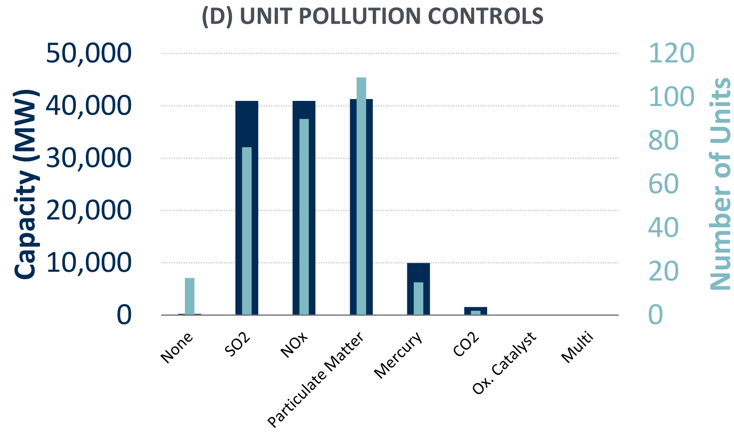
Representative Coal Plant Characteristics

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

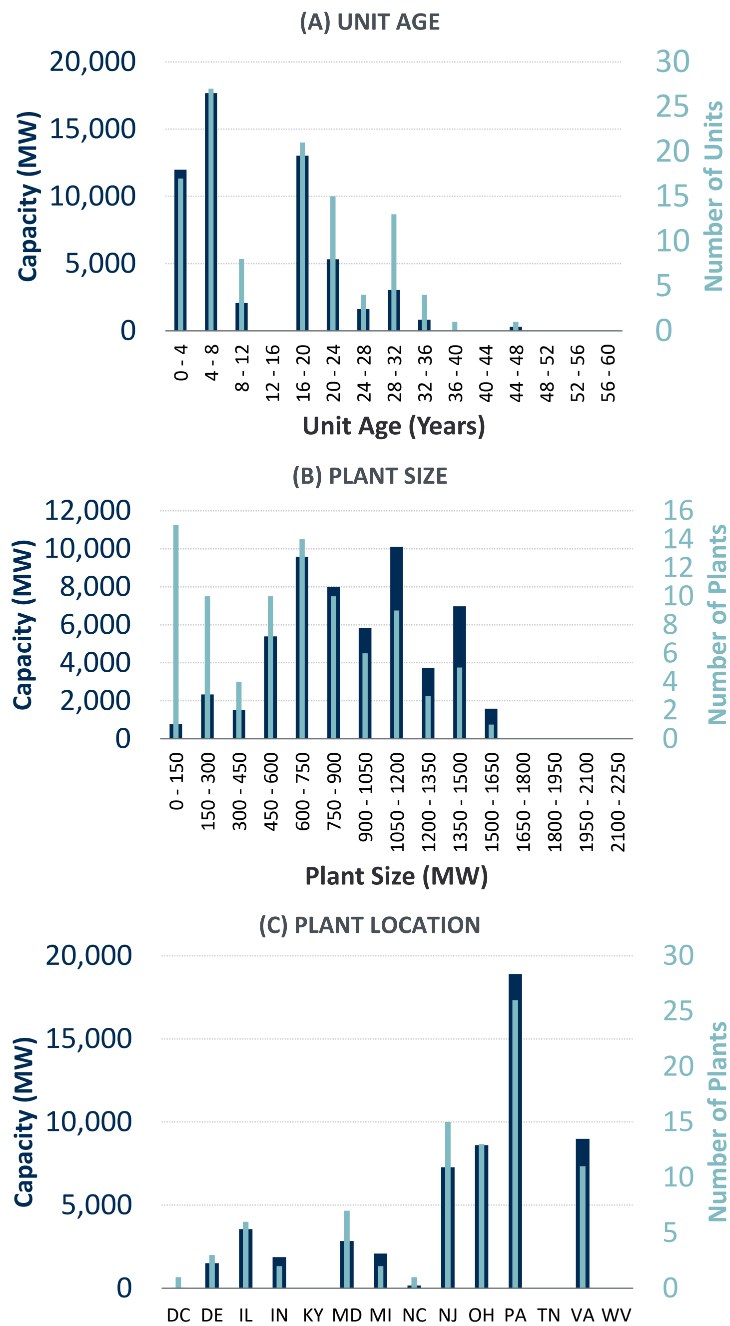
We relied on input from PJM indicating that the majority of existing CC plants have firm gas transportation contracts up to their economic maximum (EcoMax), and therefore the representative plant would be subject to this cost. Then we determined the median plant size of the CC fleet, which was 669 MW 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.

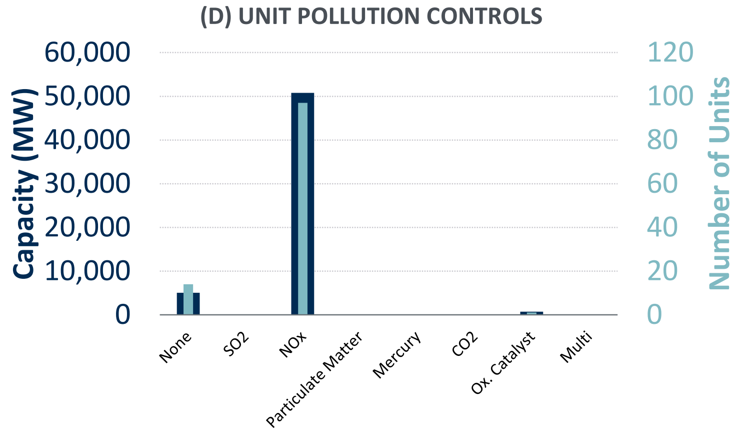
The representative high-cost and low-cost plants reflect the two modes of the bi-modal distribution of ages of CC plants in PJM. The older plants are smaller and have higher costs per MW-day, where newer plants are larger and have lower costs per MW-day with their economies of scale. Since nearly all 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 Transcontinental 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

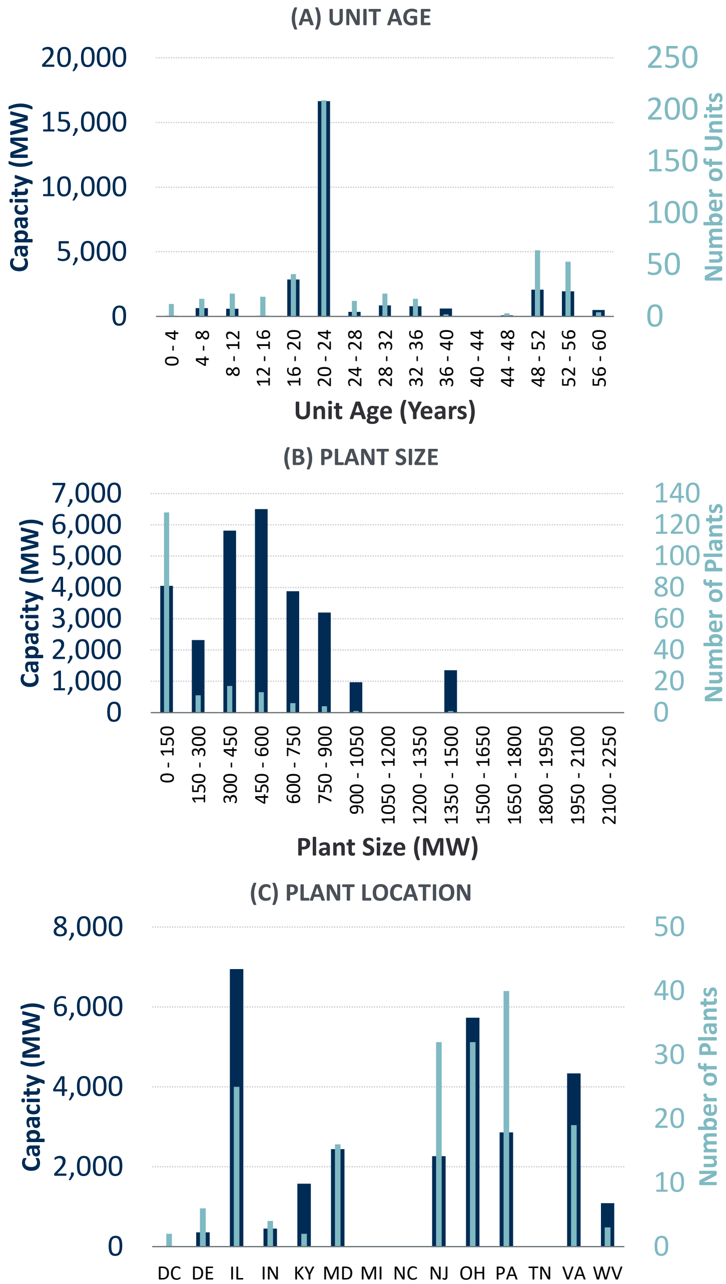
Simple-cycle combustion turbine (CT) plants include oil- and gas-fired CTs. Nearly all CTs were built around the early 2000s, but there is a wider range of sizes due to differences in the turbine technology and the number of turbines installed at each plant. There are many CT plants in the PJM fleet 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.

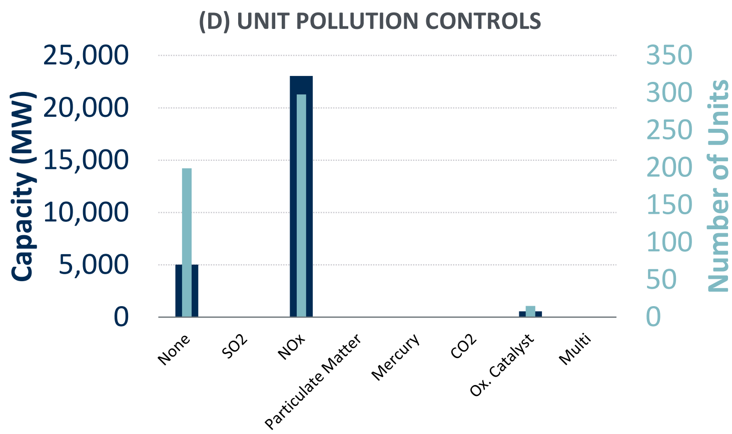
Determination of Representative Simple-Cycle Combustion Turbine Plant Characteristics

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.

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[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

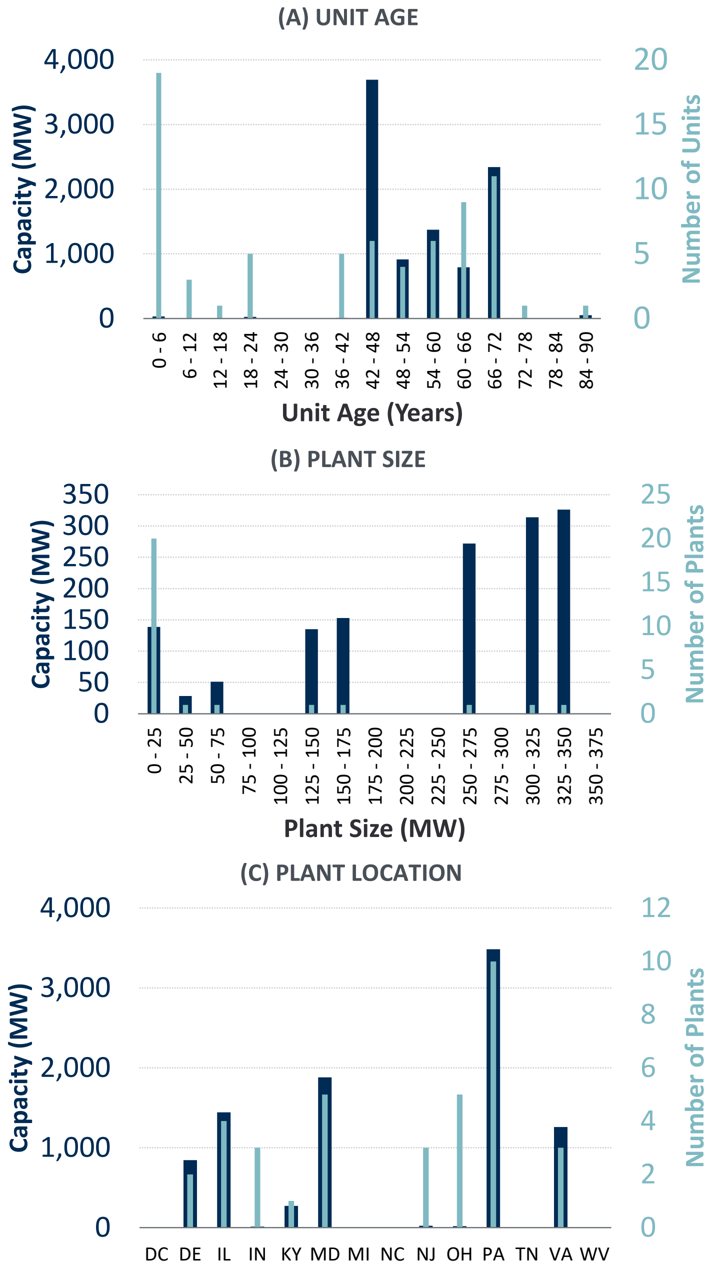
Steam turbine plants fueled by oil and gas (ST O&G) have a wide range of sizes. The majority of ST O&G plants are less than 25 MW but collectively do not contribute much capacity to the fleet. The average size is about 250 MW, which is skewed by a few very large plants on the order of 700 to 1,700 MW. 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.

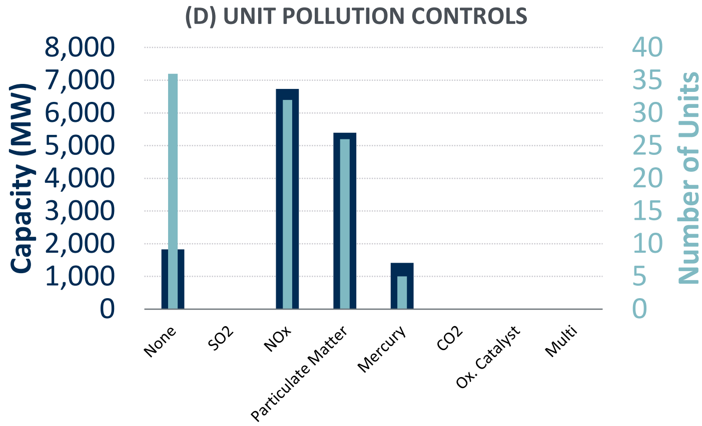
Determination of Representative Oil- and Gas-Fired Steam Turbine Plant Characteristics

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





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

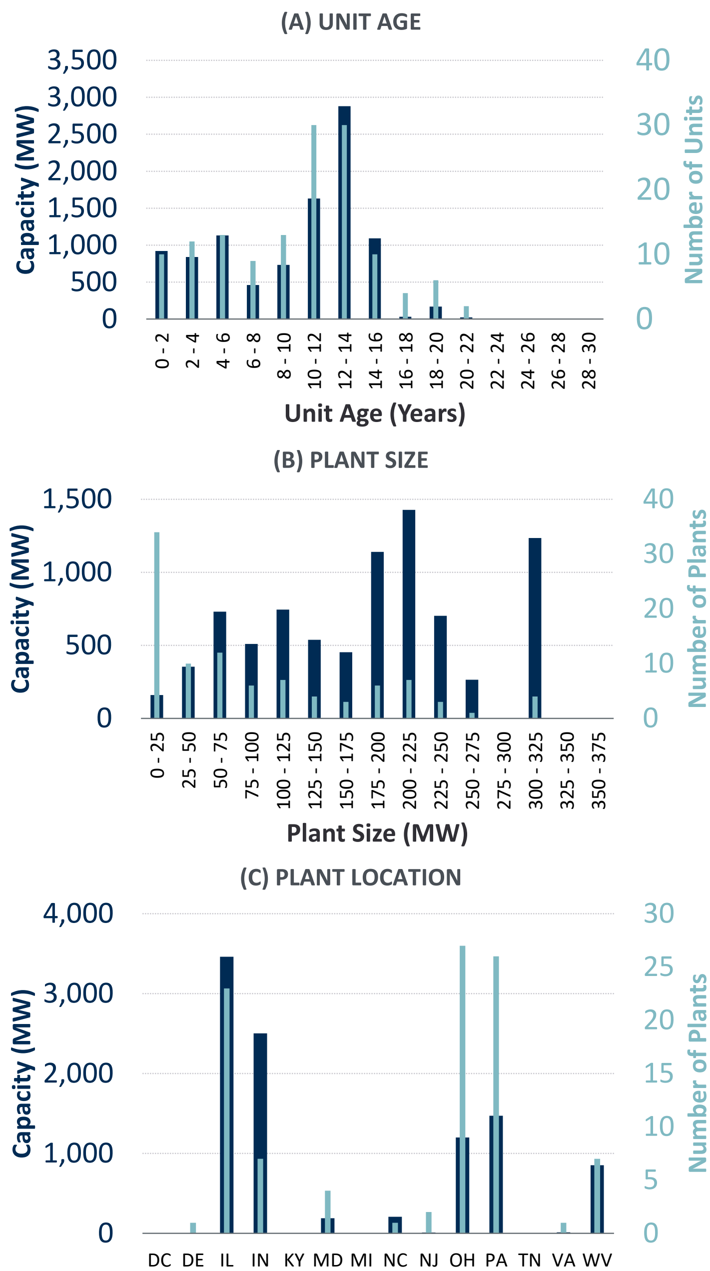
Over the past 15 years, nearly 10,000 MW of onshore wind plants have been built in PJM. The average size is 100 MW, which is skewed by the numerous small plants (less than 25 MW); however, 17 are at least 200 MW as shown in Figure 7 Panel (B) below. Plants larger than 100 MW make up of over 80% of the 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.

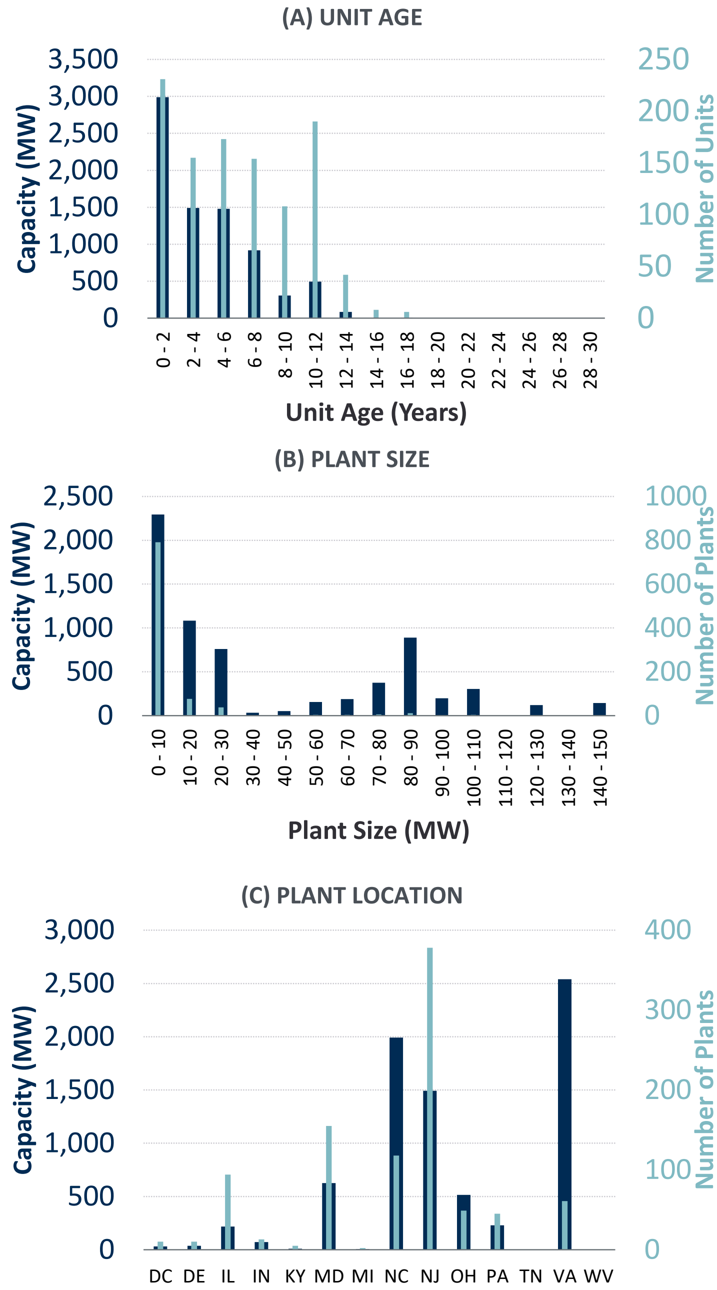
The age of a solar plant influences the plant capacity since more recent plants have tended to be built larger than in the past. Location also impacts the costs of solar PV plants due to differences in labor costs and property taxes.

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.

[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.

2021/2022 RPM Base Residual Auction Results

Executive Summary

The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2021/2022 Delivery Year as procured in the BRA is 21.5%, or 5.7% higher than the target reserve margin of 15.8%. This reserve margin was achieved at clearing prices that are between approximately 44% to 82% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in Demand Response and Energy Efficiency resources, additional wind and solar resources, and one new combined cycle gas resource.

The 2021/2022 BRA is the second where PJM has procured 100% Capacity Performance ("CP") Resources. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year. As was the case with the 2020/2021 BRA, the 2021/2022 BRA was conducted under the provisions of PJM's Enhanced Aggregation filing (Docket ER17-367-000 & 001) which was accepted by FERC on March 21, 2017.

2021/2022 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2021/2022 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $140.00/MW-day. EMAAC, PSEG, BGE, ATSI and COMED were constrained LDAs in the 2021/2022 BRA with locational price adders, in regards to the immediate parent LDA, of $25.73/MW-day, $38.56/MW-day, $60.30/MW-day, $31.33/MW-day and $55.55/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2020/2021 BRA was $76.53/MW-day. Additionally, the MAAC, EMAAC, COMED and DEOK LDA were constrained LDAs in the 2020/2021 BRA with RCPs of $86.04/MW-day, $187.87/MW-day, $188.12/MW-day and $130.00/MW-day respectively.

	2021/22 BRA Resource Clearing Prices ($/MW-day)					
Capacity Type	Rest of RTO	EMAAC	PSEG	BGE	ATSI	COMED
Capacity Performance	$140.00	$165.73	$204.29	$200.30	$171.33	$195.55

2021/2022 RPM Base Residual Auction Results

2021/2022 BRA Cleared Capacity Resources

As seen in the table below, the 2021/2022 BRA procured 893.0 MW of capacity from new generation and 508.3 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2021/2022 BRA is 4,051.8 MW which is an increase of 54.6 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2021/2022 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2021/2022 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2021/2022 BRA is 11,125.8 MW which is an increase of 3,305.4 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2021/2022 BRA is 2,832.0 MW, which is an increase of 1,121.8 MW from that procured in last year's BRA.

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2021/2022 BRA

BRA Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
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.

2021/2022 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2021/2022 BRA opened on May 10, 2018, and the results were posted on May 23, 2018.

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 2021/2022 BRA results and a discussion of the results in the context of the previous BRAs.

Summary of Results

The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. The reserve margin for the entire RTO is 21.5%, or 5.7% higher than the target reserve margin of 15.8%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2021/2022 BRA are shown in Table 1 below. EMAAC, PSEG, BGE, ATSI and COMED were constrained LDAs in the 2021/2022 BRA with locational price adders, in regards to the immediate parent LDA, of $25.73/MW-day, $38.56/MW-day, $60.30/MW-day, $31.33/MW-day and $55.55/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2020/2021 BRA was $76.53/MW-day. Additionally, the MAAC, EMAAC,

2021/2022 RPM Base Residual Auction Results

COMED and DEOK LDA were constrained LDAs in the 2020/2021 BRA with RCPs of $86.04/MW-day, $187.87/MW-day, $188.12/MW-day and $130.00/MW-day respectively.

The total Unforced Capacity (UCAP) of Generation Capacity Resources offered into this auction but not previously offered into a prior auction was 1,098.5 MW comprised of 322.2 MW of new generation units and 776.3 MW of uprates to existing or planned generation units. The quantity of new Generation Capacity Resources cleared regardless of whether they had offered into a prior auction was 1,401.3 MW comprised of 893.0 MW from new generation units and 508.3 MW from uprates to existing or planned generation units.

The quantity of Unforced Capacity procured from external Generation Capacity Resources in the 2021/2022 BRA is 4,051.8 MW which is an increase of 54.6 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2021/2022 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2021/2022 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

The total Unforced Capacity of DR procured in the 2021/2022 BRA is 11,125.8 MW which is an increase of 3,305.4 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2021/2022 BRA is 2,832.0 MW which is an increase of 1,121.8 MW from that procured in last year's 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 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.

On December 8, 2017, the Federal Energy Regulatory Commission issued a Remand Order rejecting PJM's Minimum Offer Price Rule ("MOPR") proposal in Docket No. ER13-535. As a result of the remand order all RPM Auctions conducted as of December 8, 2017, will be done so under the MOPR rules that were in effect just prior to PJM's December 7, 2012 MOPR filing. Most significantly, the competitive-entry and self-supply exemption mechanisms become immediately invalid on a prospective basis and the unit-specific exception request mechanism becomes the only means by which a sell offer of certain resource types may be submitted at a price below the MOPR Floor Offer Price. Furthermore, MOPR is applicable to the sell offer of any Generation Capacity Resource, including an uprate, regardless of the size, that has not previously cleared in an RPM Auction and is located in an LDA for which a separate VRR Curve was established for use in the BRA of the relevant delivery year, and that the unit is not a nuclear, coal, IGCC, hydroelectric, wind or solar facilities. Additionally, any External Generation Capacity Resources meeting the above criteria and that

2021/2022 RPM Base Residual Auction Results

have entered commercial operation on or after January 1, 2013 and that require sufficient transmission investment for delivery into PJM are also subject to MOPR. To avoid application of the MOPR, Capacity Market Sellers may request a unit-specific exception.

A further discussion of the 2021/2022 BRA results and additional information regarding the 2021/2022 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2021/2022 auction results to the results from the 2007/2008 through 2020/2021 RPM Auctions.

2021/2022 RPM Base Residual Auction Results

2021/2022 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins resulting from the 2021/2022 RPM BRA in comparison to those from 2007/2008 through 2020/2021 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%

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

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 2021/2022 RPM

2021/2022 RPM Base Residual Auction Results

BRA cleared 163,627.3 MW of unforced capacity in the RTO representing a 22% reserve margin. The reserve margin for the entire RTO is 21.5%, or 5.7% higher than the target reserve margin of 15.8%, when the Fixed Resource Requirement (FRR) load and resources are considered.

New Generation Resource Participation

The total Unforced Capacity of new Generation Capacity Resources offered into the auction that had not offered into a prior auction was 1,098.5 MW comprised of 322.2 MW of new generation units and 776.3 MW of uprates to existing or planned generation units. The quantity of new Generation Capacity Resources cleared in this auction regardless of whether they had offered into a prior auction was 1,401.3 MW comprised of 893.0 MW from new generation units, and 508.3 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 actually clearing in the auction. Eighty one percent of the new generation capacity that offered into the 2021/2022 BRA cleared the auction; an additional 511.8 MW of new generation capacity cleared for the first time that had previously offered into a BRA.

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	84.4	9.6	**94.0**	29.3	9.6	**38.9**
MAAC**	271.8	40.8	**312.6**	105.9	22.1	**128.0**
Total RTO	776.3	322.2	**1,098.5**	508.3	893.0	**1,401.3**

*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

2021/2022 RPM Base Residual Auction Results

Capacity Import Participation

The quantity of capacity imports cleared in the 2021/2022 BRA were 4,051.8 MW (UCAP) which represents an increase of 54.6 MW from the imports that cleared in the 2020/2021 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 2021/22 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2021/2022 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)	252.6	1,255.4	2,173.4	531.8	257.2	4,470.4
Cleared MW (UCAP)	252.6	1,251.3	1,774.9	515.8	257.2	4,051.8

* 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 2021/2022 BRA was 11,886.8 MW, representing an increase of 20.7% from the DR that offered into the 2020/2021 BRA. Of the 11,886.8 MW of total DR that offered in this auction, 11,125.8 MW cleared. The cleared DR is 3,305.4 MW greater than that which cleared in the 2020/2021 BRA. Of the 11,125.8 MW of DR cleared in the 2021/2022 BRA, 10,673.5 MW were cleared as the annual Capacity Performance Product and 452.3 MW were cleared as the summer seasonal Capacity Performance product. Table 3A contains a comparison of the DR offered and cleared in 2020/2021 BRA & 2021/2022 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. Of the 2,954.8 MW of energy efficiency that offered into the 2021/2022

BRA, 2,832.0 MW cleared in the auction. Of the 2,832.0 MW of EE Resources cleared in the 2021/2022 BRA, 2,622.7 MW was cleared as the annual Capacity Performance Product and 209.3 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 2021/2022 BRA. Approximately 93.6% of the DR and 95.8% 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 2021/2022 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 2021/2022 BRA have fallen below the levels seen in the 2014/2015 BRA.

2021/2022 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2020/2021 BRA & 2021/2022 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2020/2021*	2021/2022*	Increase in Offered MW	2020/2021*	2021/2022*	Increase in Cleared MW
EMAAC	AECO	72.5	83.6	11.1	62.8	83.4	20.6
EMAAC/DPL-S	DPL	330.0	320.3	(9.7)	213.4	265.1	51.7
EMAAC	JCPL	160.1	173.0	12.9	143.9	170.3	26.4
EMAAC	PECO	408.3	450.9	42.6	363.3	446.4	83.1
PSEG/PS-N	PSEG	353.5	423.3	69.8	327.7	407.9	80.2
EMAAC	RECO	3.8	6.0	2.2	3.7	5.8	2.1
EMAAC Sub Total		1,328.2	1,457.1	128.9	1,114.8	1,378.9	264.1
PEPCO	PEPCO	346.7	452.5	105.8	211.9	345.9	134.0
BGE	BGE	430.5	369.4	(61.1)	246.5	279.0	32.5
MAAC	METED	294.0	367.5	73.5	241.8	360.4	118.6
MAAC	PENELEC	356.6	373.5	16.9	304.1	364.5	60.4
PPL	PPL	693.5	744.5	51.0	579.9	684.7	104.8
MAAC** Sub Total		3,449.5	3,764.5	315.0	2,699.0	3,413.4	714.4
RTO	AEP	1,408.5	1,829.2	420.7	1,010.5	1,680.4	669.9
RTO	APS	933.2	1,049.7	116.5	709.8	1,019.4	309.6
ATSI/ATSI-C	ATSI	815.8	1,221.2	405.4	688.7	1,142.4	453.7
COMED	COMED	1,794.4	2,078.2	283.8	1,512.9	1,997.8	484.9
DAY	DAY	212.4	235.0	22.6	164.6	227.7	63.1
DEOK	DEOK	200.8	235.6	34.8	152.8	213.8	61.0
RTO	DOM	700.2	1,173.4	473.2	585.3	1,136.1	550.8
RTO	DUQ	192.6	140.6	(52.0)	159.9	135.4	(24.5)
RTO	EKPC	139.3	159.4	20.1	136.9	159.4	22.5
Grand Total		9,846.7	11,886.8	2,040.1	7,820.4	11,125.8	3,305.4

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

PJM #5154776

2021/2022 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered and Cleared in the 2021/2022 BRA (in UCAP MW)

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	83.6	45.4	129.0	83.4	42.4	125.8
EMAAC/DPL-S	DPL	320.3	50.4	370.7	265.1	48.0	313.1
EMAAC	JCPL	173.0	179.9	352.9	170.3	178.0	348.3
EMAAC	PECO	450.9	105.1	556.0	446.4	100.6	547.0
PSEG/PS-N	PSEG	423.3	259.2	682.5	407.9	240.1	648.0
EMAAC	RECO	6.0	8.4	14.4	5.8	7.9	13.7
EMAAC Sub Total		1,457.1	648.4	2,105.5	1,378.9	617.0	1,995.9
PEPCO	PEPCO	452.5	108.3	560.8	345.9	102.6	448.5
BGE	BGE	369.4	105.0	474.4	279.0	104.4	383.4
MAAC	METED	367.5	26.1	393.6	360.4	23.0	383.4
MAAC	PENELEC	373.5	22.5	396.0	364.5	19.3	383.8
PPL	PPL	744.5	81.3	825.8	684.7	72.4	757.1
MAAC** Sub Total		3,764.5	991.6	4,756.1	3,413.4	938.7	4,352.1
RTO	AEP	1,829.2	199.2	2,028.4	1,680.4	177.8	1,858.2
RTO	APS	1,049.7	60.0	1,109.7	1,019.4	56.4	1,075.8
ATSI/ATSI-C	ATSI	1,221.2	153.3	1,374.5	1,142.4	148.2	1,290.6
COMED	COMED	2,078.2	787.6	2,865.8	1,997.8	770.5	2,768.3
DAY	DAY	235.0	75.5	310.5	227.7	60.1	287.8
DEOK	DEOK	235.6	90.7	326.3	213.8	89.7	303.5
RTO	DOM	1,173.4	564.3	1,737.7	1,136.1	561.1	1,697.2
RTO	DUQ	140.6	32.6	173.2	135.4	29.5	164.9
RTO	EKPC	159.4	-	159.4	159.4	-	159.4
Grand Total		11,886.8	2,954.8	14,841.6	11,125.8	2,832.0	13,957.8

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

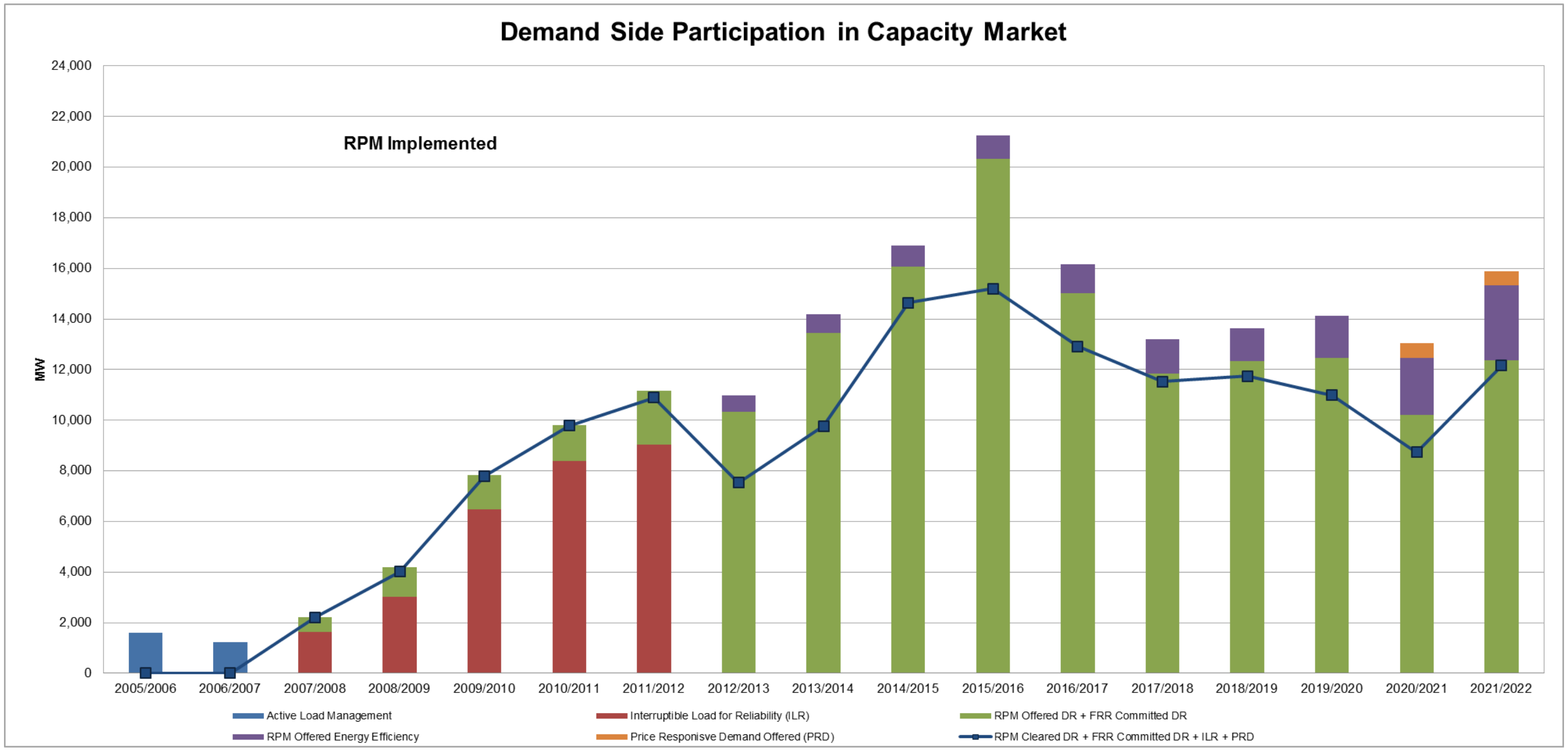
2021/2022 RPM Base Residual Auction Results

Table 3C – Breakdown of Annual and Seasonal Capacity Performance Resources by Resource Type and Season that Offered and Cleared in the 2021/2022 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	170,841.5	106.2	715.5	149,615.6	53.9	715.5
DR	11,094.6	792.2	-	10,673.5	452.3	-
EE	2,649.0	305.8	-	2,622.7	209.3	-
Grand Total	**184,585.1**	**1,204.2**	**715.5**	**162,911.8**	**715.5**	**715.5**

2021/2022 RPM Base Residual Auction Results

Figure 1 – Demand Side Participation in the PJM Capacity Market



Renewable Resource Participation

1,416.7 MW of wind resources cleared the 2021/2022 BRA as compared to 887.7 MW of wind resources that cleared the 2020/2021 BRA. Of the 1,416.7 MW of wind resources cleared in the 2021/2022 BRA, 710.2 MW were cleared as the annual Capacity Performance Product and 706.5 MW were cleared as the winter seasonal Capacity Performance product. The nameplate capability of wind resources that cleared in the 2021/2022 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,126 MW, which is 1,407 MW greater than the 6,719 MW of wind energy nameplate capability that cleared in last year's auction.

2021/2022 RPM Base Residual Auction Results

569.9 MW of solar resources cleared the 2021/2022 BRA as compared to 125.3 MW of solar resources that cleared the 2020/2021 BRA. Of the 569.9 MW of solar resources cleared in the 2021/2022 BRA, 516.0 MW were cleared as the annual Capacity Performance Product and 53.9 MW were cleared as the summer seasonal Capacity Performance product. The nameplate capability of solar resources that cleared in the 2021/2022 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 1,641 MW, which is 964 MW greater than the 677 MW of solar energy nameplate capability that cleared in last year's auction.

Price Responsive Demand Participation

A total Nominal PRD Value of 510 MW was elected and committed in the 2021/2022 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 eRPM 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 2021/2022 Planning Parameters, 510 MW of PRD across the RTO has elected to participate in the 2021/2022 BRA: 240 MW in the BGE LDA, 195 MW in the PEPCO LDA, and 75 MW in the EMAAC LDA (with 35.7 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 2021/2022 RPM Base Residual Auction. The EMAAC, PSEG, BGE, ATSI and COMED LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A pjm

2021/2022 RPM Base Residual Auction Results

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. Table 4 contains a summary of the clearing results in the LDAs from the 2021/2022 RPM Base Residual Auction.

Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

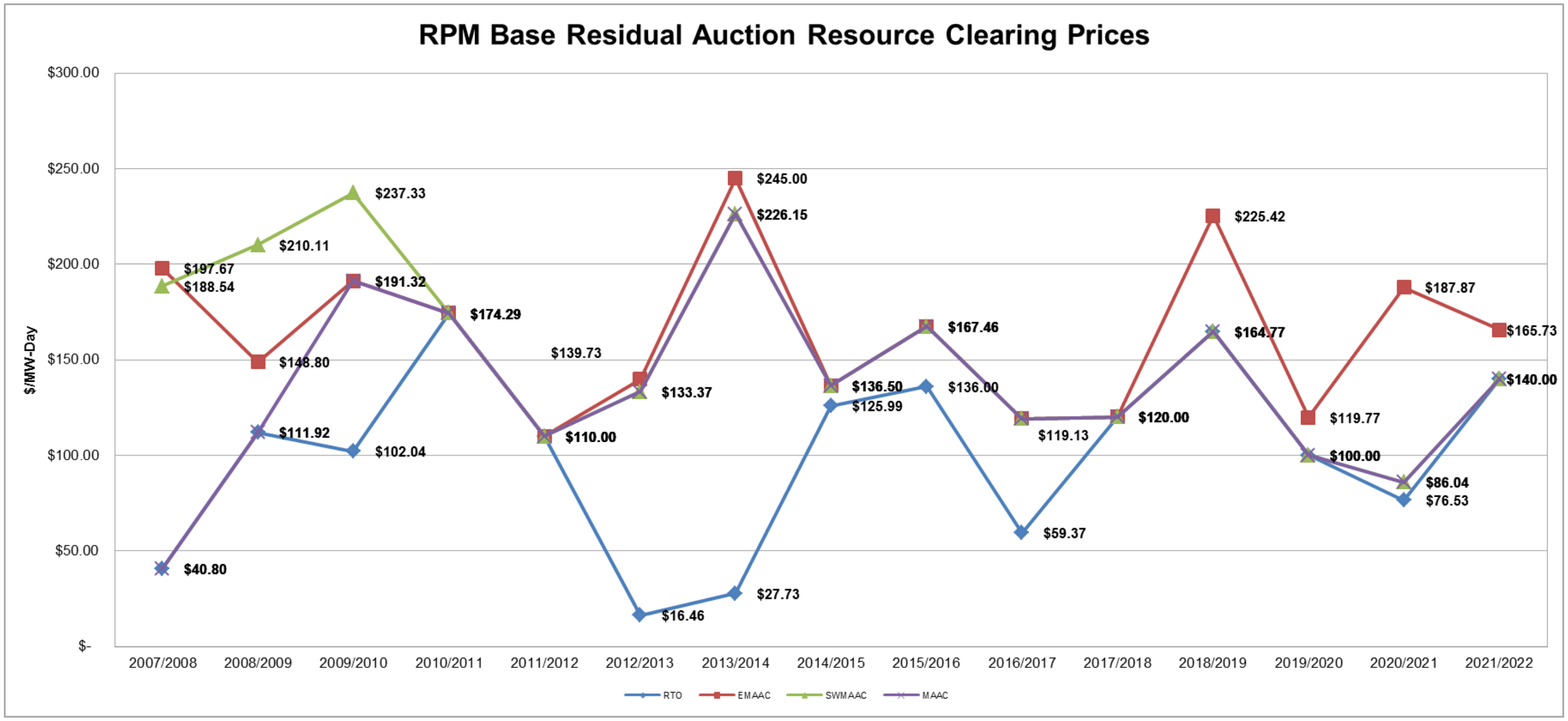
Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED	DAY	DEOK
Offered MW (UCAP)*	186,505.8	73,578.3	12,102.2	6,222.9	3,463.9	32,044.5	1,785.6	5,987.4	3,507.5	12,038.1	2,487.1	11,451.8	27,930.4	1,660.7	3,414.8
Cleared MW (UCAP)**	163,627.3	67,365.9	10,106.7	5,948.8	1,937.7	29,288.5	1,673.8	5,367.6	3,133.3	8,007.3	1,248.0	11,233.1	22,358.1	1,636.7	2,733.3
System Marginal Price	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00	$140.00
Locactional Price Adder***	$0.00	$0.00	$0.00	$0.00	$60.30	$25.73	$0.00	$38.56	$0.00	$31.33	$0.00	$0.00	$55.55	$0.00	$0.00
RCP for Capacity Performance Resources	$140.00	$140.00	$140.00	$140.00	$200.30	$165.73	$165.73	$204.29	$204.29	$171.33	$171.33	$140.00	$195.55	$140.00	$140.00

* 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 EMAAC LDA, PSEG LDA, BGE LDA, ATSI LDA and COMED LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2021/2022 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.

2021/2022 RPM Base Residual Auction Results

Figure 2 – Base Residual Auction Resource Clearing Prices



* 2014/2015 through 2021/2022 Prices reflect the Annual Resource Clearing Prices.

2021/2022 RPM Base Residual Auction Results

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2021/2022 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 216,350.2 MW of installed capacity was eligible to be offered into the 2021/2022 Base Residual Auction, with 4,725.0 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2021/2022 auction was unchanged from that of the previous auction and FRR commitments decreased by 274.2 MW from the 2020/2021 Delivery Year to 13,657.4 MW.

A total of 192,449.2 MW of capacity was offered into the Base Residual Auction. This is an increase of 2,531.4 MW from that which was offered into the 2020/2021 BRA. A total of 23,901.0 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests not yet reflected in eRPM, 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.

2021/2022 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**
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
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
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**
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
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
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
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**
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**
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
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
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
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**
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**

[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 186,504.8 MW were offered into the 2021/2022 BRA, comprised of 171,663.2 MW of generation capacity, 11,886.8 MW of capacity from DR, and 2,954.8 MW of capacity from EE resources. Of those offered, a total of 163,627.3 MW of capacity was cleared in the BRA.

Of the 163,627.3 MW of capacity that cleared in the auction, a total of 150,385.0 MW cleared from Generation Capacity Resources, 11,125.8 MW cleared from DR, and 2,832.0 MW cleared from EE resources. Of which, 715.5 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 First, Second and Third Incremental Auctions for the 2021/2022 Delivery Year.

2021/2022 RPM Base Residual Auction Results

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**
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
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
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
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**
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
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
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
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**
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

* 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 Performa

***Starting 2020/2021: Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

2021/2022 RPM Base Residual Auction Results

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2021/2022 BRA. A total of 1,196.9 MW of incrementally new capacity in PJM was available for the 2021/2022 BRA. This incrementally new 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, and supplemented by an increase in the quantity of offered DR and EE to yield a net increase of 2,020.2 MW of installed capacity as compared to last year's BRA.

Table 7 also illustrates the total amount of resource additions and reductions over fifteen Delivery Years since the implementation of the RPM construct. Over the period covering the first fifteen RPM BRAs, 51,988.9 MW of new generation capacity was added, which was partially offset by 41,331.2 MW of capacity de-ratings or retirements over the same period. Additionally, 11,349.7 MW of new DR and 2,713.8 MW of new EE resources were offered over the course of the fifteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last fifteen RPM auctions was 24,721.2 MW.

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	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	51,988.9
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	-41,331.2
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	11,349.7
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	2,713.8
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**	**24,721.2**

* 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

2021/2022 RPM Base Residual Auction Results

Table 7A provides a further breakdown of the generation increases and decreases for the 2021/2022 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2021/2022 Delivery Year

LDA Name	Increases	Decreases
EMAAC	102.3	(640.2)
MAAC*	330.4	(712.2)
Total RTO**	**1,196.9**	**(1,691.7)**

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 reduction in generating capacity from new resources and uprates to existing resources offered into the 2021/2022 BRA as compared to last year's BRA. The capacity offered in the 2021/2022 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, wind, and solar resources. As shown in Figure 3, the largest growth remains in combined cycle plants.

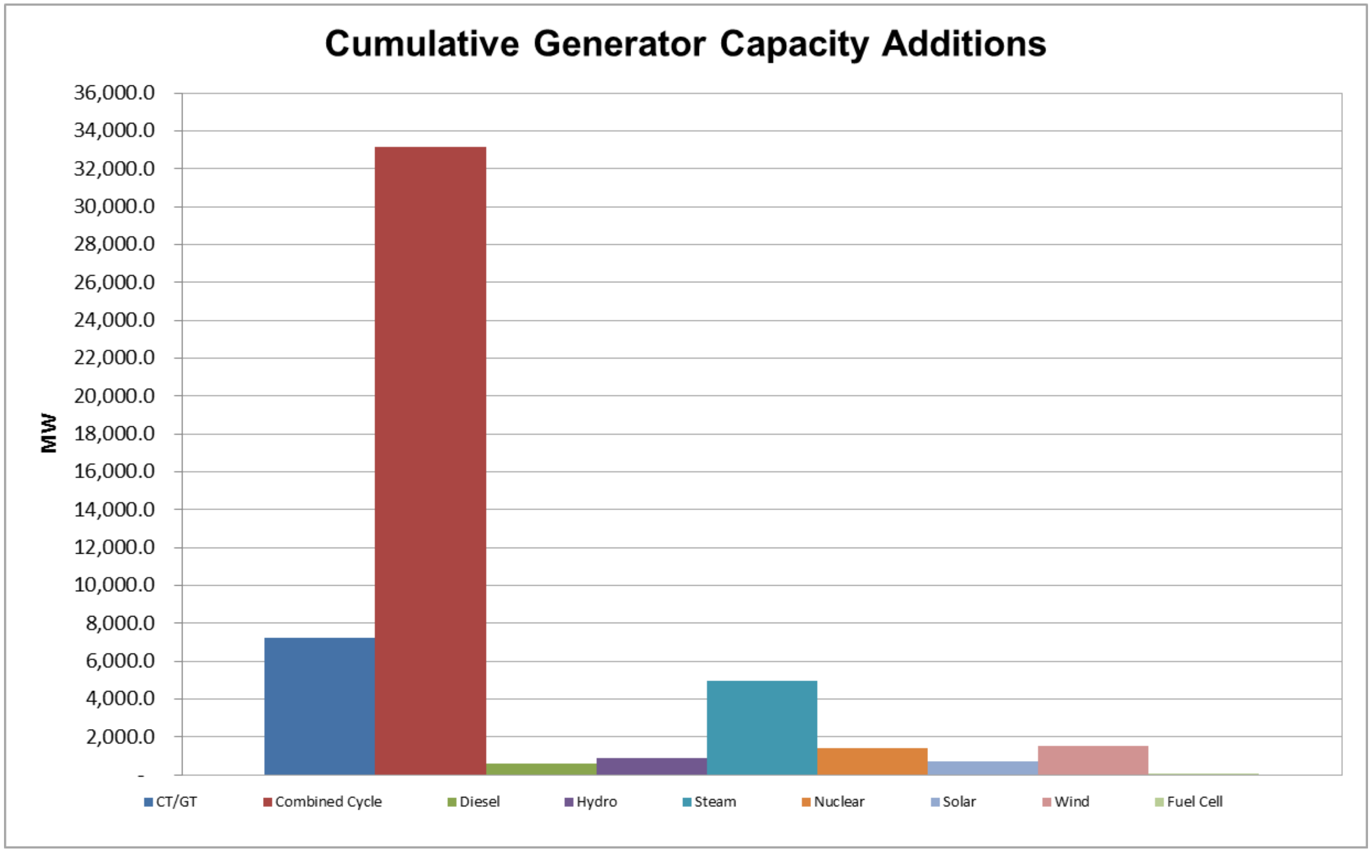
2021/2022 RPM Base Residual Auction Results

Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2021/2022

	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
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										-
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
	Total	7,215.5	33,134.9	581.6	894.4	4,957.4	1,402.3	715.3	1,536.3	30.0	50,467.7

2021/2022 RPM Base Residual Auction Results

Figure 3: Cumulative Generation Capacity Increases by Fuel Type



2021/2022 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 2021/2022 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 7,588.7 MW of cleared UCAP in the 2021/2022 BRA which equates to 9,207.6 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	3,349.6	3,128.1
Postponed or Cancelled Retirement	4,355.2	3,758.5
Reactivation	1,502.8	702.1
Total	**9,207.6**	**7,588.7**

RPM Impact to Date

As illustrated in Table 5, for the 2021/2022 auction, the capacity exports were 1,319.8 MW and the offered capacity imports were 4,725.0 MW. The difference between the capacity imports and exports results is a net capacity import of 3,405.2 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 3,405.2 MW. Therefore, RPM's impact on PJM capacity interchange is 6,021.2 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2021/2022 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 2021/2022 compared to what would have happened absent this implementation is 77,773.0 MW.

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	38,919.4
Generation Upgrades (not including reactivations)	9,997.6
Generation Reactivation	1,550.7
Forward Demand and Energy Efficiency Resources	14,063.5
Cleared ICAP from Withdrawn or Cancelled Retirements	7,220.6
Net increase in Capacity Imports	6,021.2
Total Impact on Capacity Availability in 2021/2022 Delivery Year	**77,773.0**

2021/2022 RPM Base Residual Auction Results

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2021/2022 RPM BRA clearing prices relative to 2020/2021 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 forecast peak load for the PJM RTO for the 2021/2022 Delivery Year is 152,647.4 MW which is 1,267.6 MW or about 0.8% below the forecast peak load of 153,915 MW for the 2020/2021 BRA. This reduction was manifested in a 1,200 MW decrease in the reliability requirement for the RTO as compared to last year's BRA.

- 510 MW of Price Responsive Demand has elected to participate in the 2021/2022 Base Residual Auction: 240 MW in the BGE LDA, 195 MW in the PEPCO LDA, and 75 MW in the EMAAC LDA (with 35.7 MW located in the DPL-South LDA).

- The Net CONE used to develop the VRR Curve increased for the RTO and for all of the modeled LDAs. The increase in Net CONE values was driven primarily by a decrease in the Net E&AS for the RTO and all LDAs. The Net E&AS values for the 2021/2022 BRA were lower than those of the 2020/2021 BRA because the updated three-year rolling average Net E&AS replaced 2014 calendar year values with 2017 calendar year values, with the 2014 calendar year Net E&AS values being significantly greater than the 2017 calendar year Net E&AS values.

Changes that impacted the Supply Curve:

- The 2021/2022 BRA is the second BRA for which PJM has procured only Capacity Performance ("CP") Resources.
  - Annual CP capacity offered by intermittent resources is 928.7 MW higher than the annual CP capacity offered by intermittent resources in the 2020/2021 BRA.
  - Annual CP capacity offered by DR is 2,727.4 MW higher than the annual CP capacity offered by DR in the 2020/2021 BRA.

2021/2022 RPM Base Residual Auction Results

- Annual CP capacity offered by EE is 810.0 MW higher than the annual CP capacity offered by EE in the 2020/2021 BRA.

- 715.5 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. This is an increase of 317.5 MW over the 398 MW of seasonal capacity resources that cleared in an aggregated manner in the 2020/2021 BRA. 715.5 MW of summer CP resources comprised of 452.3 MW of summer DR, 209.3 MW of summer EE and 53.9 MW of intermittent resources cleared along with 715.5 MW of winter CP resources comprised mainly of winter capability from wind resources.

- New generation capacity of 1,098.5 MW was offered into the BRA comprised of 322.2 of new generation and 776.3 MW of uprates.

- In general, offer prices from supply resources were higher in this auction compared to the prior auction, likely reflecting the continuing decrease in energy revenues and the associated impact on revenues required from the capacity market.

Michigan Public Power Agency

809 Centennial Way

Lansing, Michigan 48917

FINANCIAL STATEMENTS

December 31, 2023

MICHIGAN PUBLIC POWER AGENCY

Table of Contents

December 31, 2023

MICHIGAN PUBLIC POWER AGENCY

Table of Contents

December 31, 2023

Independent Auditors' Report

To the Board of Commissioners of
Michigan Public Power Agency

Opinions

We have audited the accompanying financial statements of the business-type activities and each major fund of the Michigan Public Power Agency (the Agency), as of and for the year ended December 31, 2023 and the related notes to the financial statements, which collectively comprise the Agency's basic financial statements as listed in the table of contents.

In our opinion, the accompanying financial statements referred to above present fairly, in all material respects, the financial position of the business-type activities and each major fund of the Agency as of December 31, 2023 and the changes in financial position and cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinions

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

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 Agency's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditors' 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 auditors' report that includes our opinions. 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 Agency's 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 Agency's 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.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis be presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Supplementary Information

Our audit was conducted for the purpose of forming opinions on the basic financial statements as a whole. The supplementary information as listed in the table of contents is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the basic financial statements. The information has been subjected to the auditing procedures applied in the audit of the basic financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the financial statements or to the basic financial statements themselves and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the supplementary information is fairly stated in all material respects, in relation to the financial statements as a whole.

Prior Year Comparative Information

We have previously audited the Agency's 2022 financial statements and we expressed unmodified audit opinions on the respective financial statements of the business-type activities and each major fund in our report dated April 6, 2023. In our opinion, the summarized comparative information presented herein as of and for the year ended December 31, 2022 is present fairly, in all material respects, with the audited financial statements from which it has been derived.

Baker Tilly US, LLP

Madison, Wisconsin
April 4, 2024

MANAGEMENT'S DISCUSSION AND ANALYSIS (UNAUDITED)

The management of Michigan Public Power Agency (MPPA) offers all persons interested in the financial position of MPPA this narrative, overview, and analysis of MPPA's financial performance during the years ended December 31, 2023, and 2022. It should be read in conjunction with MPPA's financial statements and the accompanying notes.

OVERVIEW OF THE FINANCIAL STATEMENTS

This annual report consists of two parts: Management's Discussion and Analysis (this section) and the basic financial statements. MPPA is a municipal power joint action agency and follows proprietary fund reporting; accordingly, the financial statements are presented using the economic resources measurement focus and the accrual basis of accounting. Proprietary fund statements offer financial information about the activities and operations of MPPA.

The financial statements are designed to provide readers with a broad overview of MPPA's finances, in a manner like a private sector business.

MPPA owns and administers eight Projects. Seven Projects provide power supply resources and services and one, the General Fund, invests in and manages the infrastructure and systems to operate the General Agency. These Projects are:

- Campbell #3
- Belle River
- Combustion Turbine
- Energy Services
- Transmission
- Landfill Renewable Energy
- AMP Fremont Energy Center (AFEC)
- General Fund

MPPA has different participating members in each Project who are each responsible for their share of all administrative, debt service, and operating expenses.

Each Project is financially independent from one another, supported entirely by the participating members. No monies can be shared between Projects.

The Statement of Revenues, Expenses, and Changes in Net Position presents information reflecting changes in MPPA's net position during the most recent year. All changes in net position are reported as soon as the underlying event giving rise to the change occurs, regardless of the timing of the related cash flows. Thus, revenues and expenses are reported in this statement for some items that will result in cash flows in future fiscal periods.

OVERVIEW OF THE FINANCIAL STATEMENTS (cont.)

The Statement of Cash Flows reports the cash provided and used by operating activities, as well as other cash sources such as investment income and cash payments for repayment of bonds and capital additions.

The notes provide additional information that is essential to a full understanding of the data provided in the financial statements. The notes to the financial statements can be found beginning on page 16 of this report.

MPPA FINANCIAL ANALYSIS

An analysis of MPPA's financial position begins with a review of the Statement of Net Position and the Statement of Revenues, Expenses, and Changes in Net Position. These two statements report MPPA's net position and changes therein. Consideration must be taken when evaluating MPPA's financial position and results of operations when using the financial presentations due to the legal separation that must be maintained between projects. However, broad patterns and trends may be observed at this level that should lead the reader to carefully study the financial statements of each project.

A summary of MPPA's Statement of Net Position is presented below in Table 1. The Statement of Revenues, Expenses, and Changes in Net Position is summarized in Table 2.

MPPA uses fund accounting, Federal Energy Regulatory Commission (FERC) accounting, and special utility industry terminology to ensure and demonstrate compliance with finance-related legal requirements.

MPPA FINANCIAL ANALYSIS (cont.)

Table 1
Statement of Net Position

	2023	2022
Current Assets	$ 117,916,015	$ 105,964,578
Non-Current Assets		
Capital Assets	185,566,528	192,432,408
Other Assets	23,123,733	23,581,489
Total Assets	**326,606,276**	**321,978,475**
Deferred Outflows of Resources	4,528,430	4,689,849
Current Liabilities		
Accrued Interest Payable	231,723	263,180
Revenue Bonds Payable	4,370,000	4,300,000
Other Current Liabilities	26,159,882	31,732,137
Total Current Liabilities	30,761,605	36,295,317
Non-Current Liabilities		
Liabilities Payable from Restricted Assets		
Member Deposits	26,508,748	26,018,728
Asset Retirement Obligation	5,490,290	5,330,115
Revenue Bonds Payable, Less Current Portion	26,280,000	30,650,000
Total Non-Current Liabilities	58,279,038	61,998,843
Total Liabilities	**89,040,643**	**98,294,160**
Deferred Inflows of Resources	693,573	888,196
Net Position		
Net Investment in Capital Assets	154,222,955	156,594,212
Restricted	4,672,487	4,596,092
Unrestricted	82,505,048	66,295,664
Total Net Position	**$ 241,400,490**	**$ 227,485,968**

MPPA FINANCIAL ANALYSIS (cont.)

Table 2
Condensed Statement of Revenues, Expenses, and Changes in Net Position

	2023	2022
Gross Operating Revenues	$ 259,878,345	$ 299,552,671
Non-Operating Revenues	4,158,331	853,252
Total Revenues	**264,036,675**	**300,405,923**
Depreciation Expense	17,117,076	17,348,882
Other Operating Expenses	232,544,207	271,601,233
Non-Operating Expenses	460,870	1,717,514
Total Expenses	**250,122,153**	**290,667,630**
Change in Net Position	**$ 13,914,522**	**9,738,294**
Beginning Net Position	**227,485,968**	**217,747,674**
Ending Net Position	**$ 241,400,490**	**$ 227,485,968**

Campbell #3 Project

MPPA has a 4.8% undivided ownership share in J.H Campbell Unit #3, a coal-fired electric generation resource located in Ottawa County, Michigan. Consumers Energy, a regulated operating subsidiary of CMS Energy Corporation, and Wolverine Power Supply Cooperative own the remaining shares of the facility. 10 of MPPA's members participate in this Project. MPPA's 2023 share of the Project's generation was 239,156 MWhs compared with 2022's generation of 255,451 MWhs. The total operating cost was $42.15/MWh vs $41.63/MWh in 2022. Project capacity factor in 2023 was 67.5% compared to 72.1% in 2022.

Belle River Project

MPPA has a 18.61% undivided ownership share in Belle River Power Plant, a coal-fired electric generation resource in St. Clair County, Michigan. DTE Electric, a regulated operating subsidiary of DTE Energy, owns the remaining share of the facility. 11 of MPPA's members participate in this Project. MPPA's 2023 share of the Project's generation was 1,081,856 MWhs compared with 2022's generation of 1,243,961 MWhs. The total operating cost was $47.88/MWh vs $54.03/MWh in 2022. Project capacity factor in 2023 was 51.0% compared to 61.2% in 2022.

MPPA FINANCIAL ANALYSIS (cont.)

Combustion Turbine Project

MPPA owns 100% of the Combustion Turbine Project, a natural gas fired electric generation peaking resource located in Kalkaska County, Michigan. Five of MPPA's members participate in this Project. Project generation in 2023 was 54,536 MWhs compared with 2022's generation of 43,487 MWhs. The total operating cost was $81.08/MWh vs $138.03/MWh in 2022. Project capacity factor in 2023 was 11.3% compared to 9.0% in 2022.

Energy Services Project

MPPA owns 100% of the Energy Services Project (ESP). ESP is a contracted power project that executes power purchase agreements with wholesale market participants and developers. ESP also provides market operation services interfacing participating member load and supply resources in wholesale power markets. 21 of MPPA's members participate in this Project. The Project provided 1,972,929 MWhs of energy to its members at an average energy cost of $52.01/MWh in 2023 compared to 2,038,917 MWhs at an average energy cost of $59.85/MWh in 2022.

Landfill Renewable Energy Project

MPPA owns 100% of the Landfill Renewable Energy Project. This is a contracted power project where MPPA purchases all power supply and environmental attributes produced by designated landfill gas fueled power generation resources. 14 of MPPA's members participate in this Project. MPPA purchased a total of 125,643 MWhs in 2023 at an average energy cost, offset by the sale of renewable energy credits, of $98.47/MWh compared to 132,721 MWhs at an average energy cost of $96.15/MWh in 2022.

Transmission Project

MPPA has varying percentages of undivided ownership in designated high voltage electric transmission facilities in Michigan. 13 of MPPA's members participate in this Project.

AMP Fremont Energy Center Project (AFEC)

MPPA has a 5.16% undivided ownership share in the Fremont Energy Center, a natural gas fired combined cycle electric power generation resource located in Sandusky County, Ohio. American Municipal Power (AMP) owns the remaining share of the Project. 13 of MPPA's members participate in this Project. MPPA's 2023 share of the Project's generation was 182,084 MWhs compared with 2022's generation of 220,150 MWhs. The total operating costs for the plant were $50.06/MWh vs $54.82/MWh in 2022. Project capacity factor in 2023 was 59.7% compared to 66.8% in 2022.

General Fund

MPPA's General Fund manages Agency activities that are not directly tied to a specific project. The General Fund is financed by member dues that are based on the annual budgeted operating expenses and capital requirements.

MPPA FINANCIAL ANALYSIS (cont.)

General Fund (cont.)

The General Fund also includes an overhead contribution from MPPA's service committees, MMEA, and Associate Member dues. The service committees provide a venue for MPPA Members and municipal utilities that are not MPPA members to participate in activities that do not require financing or the acquisition of assets, including power supply exploration, regulatory compliance, and member operations. The service committees are treated as separate sub-accounts under the General Fund for accounting purposes.

CAPITAL ASSETS

MPPA's investment in capital assets as of December 31, 2023, is $185,566,528 (net of accumulated depreciation). This investment in capital assets includes investment in plants, transmission systems, land, buildings, improvements, machinery, and equipment. See Note 6 for additional details.

LONG-TERM DEBT

On December 31, 2023, MPPA had a total of $89,040,643 in total outstanding liabilities. Of this amount, the following represents bond payments payable:

Long Term Debt - Bonds

Combustion Turbine #1 Project	$ 8,330,000
AMP Fremont Energy Center Project (AFEC)	22,320,000
	$ 30,650,000

See Note 7 for additional details.

RISK FACTORS & CONSIDERATIONS

The electric utility industry is undergoing a significant transformation. The forces of decarbonization, decentralization, and consumerization driven by technological innovation is rapidly changing how electricity is produced, delivered, and consumed. Public Policy and Law changes at the State and Federal level, along with consumer preferences, are driving significant investment in clean energy and related technologies. Public power utilities and municipal power joint action agencies like MPPA face several risk factors driven by this transformation as well as traditional risks of operating in the electric utility industry. These factors include, but are not limited to: 1) meeting future reliability requirements with rapidly changing power supply resource technologies, 2) end-use customer preferences to own and/or control power supply decisions, 3) potential changes to federal and state energy laws and/or regulatory compliance that could impact the operation of the electric generating units we own or contract supply from, 4) increased competition to serve our member end-use customers from independent power producers, distributed generation, and energy marketers, 5) ability to issue tax exempt financing at competitive rates , 6) load forecasting uncertainty due to economic factors, load growth, energy efficiency, or customer control technologies, 7) volatility of the pricing and/or availability of fuel used to produce power, 8) inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy, capacity, fuel, and transmission, and 9) issues relating to cyber security failures. Any of these risk factors, as well as other factors, may influence the financial condition of MPPA and/or its municipal members.

The Clean Energy & Climate Action Package of energy legislation signed by Michigan Governor Whitmer in November 2023 as well as the Infrastructure Investment and Jobs Act passed in November 2021 and the Inflation Reduction Act passed in August of 2022 are and will continue to have significant impact on the electric utility industry. These laws are designed, among other objectives, to modernize energy infrastructure and transition to a clean energy economy. MPPA and its members must navigate implementation of these laws to ensure equal treatment as well as ensure we continue to provide reliable and affordable power supply.

MICHIGAN LEGISLATION

In November 2023, Governor Gretchen Witmer signed clean energy legislation that focused on implementing into law recommendations from the MI Healthy Climate Plan, an Executive Directive released in April of 2022. The clean energy legislation addresses renewable energy standards, clean energy objectives, energy waste reduction, distributed generation, and siting of renewable energy projects. Public Act 235 mandates that all electric providers achieve a renewable energy supply portfolio of at least 15% through 2029, 50% by 2030 through 2034, and 60% in 2035 and each year thereafter. Municipal electric utilities may meet these requirements through investment in renewable power supply resources, purchasing power from renewable energy resources, or purchasing renewable energy credits (RECs) within the territory of the utility's regional transmission organization (RTO). RECs can be used to meet 100% of these requirements through 2035. In addition, electric providers must meet a clean energy standard of at least 80% in 2035 through 2039 and 100% in 2040 and each year thereafter. Clean energy is derived from a system that does not emit greenhouse gas, including fossil fuel with carbon capture, renewable energy, and nuclear energy. The governing body of a municipally owned electric utility may grant an extension of the clean energy standard if compliance is not practically feasible due to zoning, siting, permitting, supply chains, transmission interconnections, labor shortages, delays in project deliverability from developers, unanticipated load growth, or other reasons that may be provided.

Public Act 229 reinstates the energy waste reduction (EWR) plan for municipal electric utilities and cooperatives. Each year, beginning in 2026, an EWR plan shall collectively achieve incremental energy savings equivalent to 1.5% of total retail electricity sales in megawatt hours calculated from the preceding year. It also requires each utility to offer a low-income EWR program.

Since 2022, the Michigan Municipal Electric Association spent considerable time advocating for legislation that would provide Michigan's municipal power Joint Action Agencies more flexibility in how they conduct meetings while staying in compliance with the Open Meeting Act (OMA). Legislative amendments to the OMA were made and became effective in February 2024.

CONTACTING MPPA'S FINANCIAL MANAGEMENT

This financial report is designed to provide our members, investors, and creditors with a general overview of MPPA's finances. Questions concerning any of the information provided in this report or requests for additional financial information should be addressed to Laurie Valasek, CFO, Michigan Public Power Agency, lvalasek@mpower.org.

MICHIGAN PUBLIC POWER AGENCY
STATEMENT OF NET POSITION
December 31, 2023
(With Comparative Totals for December 31, 2022)

	CAMPBELL # 3	BELLE RIVER	COMBUSTION TURBINE	TRANSMISSION PROJECT	LANDFILL PROJECT	AFEC PROJECT	ENERGY SVCS PROJECT	GENERAL FUND	TOTALS 2023	TOTALS 2022
CURRENT ASSETS										
Cash & Cash Equivalents										
Operation & Maintenance Account	$ 1,461,840	$ 10,401,675	$ 646,482	$ 503,677	$ 994,534	$ 1,686,135	$ 5,443,794	$ -	$ 21,138,137	$ 21,431,947
Project Account	3,631,254	13,686,865	3,305,168	-	-	5,336,241	-	-	25,959,528	9,601,413
Working Capital / Other	-	-	-	-	133,505	-	12,829,579	1,516,800	14,479,884	11,234,648
Total Cash and Cash Equivalents	5,093,094	24,088,540	3,951,650	503,677	1,128,039	7,022,376	18,273,373	1,516,800	61,577,549	42,268,008
Restricted Cash - Debt Service	-	-	2,103,596	-	-	2,516,004	-	-	4,619,600	4,574,662
Investments - Unrestricted	2,303,019	5,720,400	842,395	134,086	288,719	1,862,828	4,568,159	487,015	16,206,621	18,464,215
Accrued Interest Receivable	25,871	83,365	12,276	1,954	4,208	27,148	66,573	7,097	228,492	153,766
Accounts Receivable	1,469,186	11,278,499	796,312	418,539	-	112,580	5,387,268	40,031	19,502,415	25,441,900
Fuel Inventory	1,094,631	9,376,189	101,801	-	-	-	-	-	10,572,621	10,375,874
Materials & Supplies Inventory	-	5,102,174	106,543	-	-	-	-	-	5,208,717	4,686,153
Total Current Assets	**9,985,801**	**55,649,167**	**7,914,573**	**1,058,256**	**1,420,966**	**11,540,936**	**28,295,373**	**2,050,943**	**117,916,015**	**105,964,578**
NON-CURRENT ASSETS										
Capital Assets										
Utility Plant	85,885,634	491,763,177	33,153,037	3,335,511	-	32,563,118	-	-	646,700,477	646,995,654
Building & Land	244,547	154,027	48,500	-	-	27,598	-	1,834,177	2,308,849	2,253,900
Accumulated Depreciation	(51,400,793)	(379,542,944)	(20,603,374)	(560,588)	-	(9,932,129)	-	(1,402,970)	(463,442,798)	(456,817,146)
Net Property & Equipment	34,729,388	112,374,260	12,598,163	2,774,923	-	22,658,587	-	431,207	185,566,528	192,432,408
Prepaid Expenses & Deposits	760,145	3,890,000	117,833	-	-	771,120	-	499,586	6,038,684	5,281,952
Designated Cash										
O & M / Fuel Reserve	1,050,000	-	-	-	-	-	-	-	1,050,000	1,050,000
Investments - Unrestricted	3,254,596	5,141,201	757,102	120,510	259,486	1,674,214	4,105,626	437,704	15,750,439	16,964,927
Restricted Cash - Other	-	-	-	-	-	284,610	-	-	284,610	284,610
Total Non-Current Assets	**39,794,129**	**121,405,461**	**13,473,098**	**2,895,433**	**259,486**	**25,388,531**	**4,105,626**	**1,368,497**	**208,690,261**	**216,013,897**
TOTAL ASSETS	**49,779,930**	**177,054,628**	**21,387,671**	**3,953,689**	**1,680,452**	**36,929,467**	**32,400,999**	**3,419,440**	**326,606,276**	**321,978,475**
DEFERRED OUTFLOWS OF RESOURCES										
Asset Retirement Obligations	$ 4,023,374	$ 505,056	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,528,430	$ 4,689,849

MICHIGAN PUBLIC POWER AGENCY
STATEMENT OF NET POSITION
December 31, 2023
(With Comparative Totals for December 31, 2022)

	CAMPBELL # 3	BELLE RIVER	COMBUSTION TURBINE	TRANSMISSION PROJECT	LANDFILL PROJECT	AFEC PROJECT	ENERGY SVCS PROJECT	GENERAL FUND	TOTALS 2023	TOTALS 2022
CURRENT LIABILITIES										
Accounts Payable and Accrued Expense	$ 783,772	$ 12,980,248	$ 331,096	$ 792,212	$ 1,383,616	$ 205,153	$ 8,868,322	$ 697,630	$ 26,042,049	$ 31,612,137
Member Deposits/Security Deposits	-	-	117,833	-	-	-	-	-	117,833	120,000
Liabilities Payable from Restricted Assets										
Accrued Interest Payable	-	-	55,395	-	-	176,328	-	-	231,723	263,180
Revenue Bonds Payable - Current	-	-	2,040,000	-	-	2,330,000	-	-	4,370,000	4,300,000
Total Current Liabilities	**783,772**	**12,980,248**	**2,544,324**	**792,212**	**1,383,616**	**2,711,481**	**8,868,322**	**697,630**	**30,761,605**	**36,295,317**
NON-CURRENT LIABILITIES										
Member Deposits	760,145	3,890,000	-	-	133,505	-	21,725,098	-	26,508,748	26,018,728
Revenue Bonds Payable	-	-	6,290,000	-	-	19,990,000	-	-	26,280,000	30,650,000
Asset Retirement Obligation	4,803,167	687,123	-	-	-	-	-	-	5,490,290	5,330,115
Total Non-Current Liabilities	**5,563,312**	**4,577,123**	**6,290,000**	**-**	**133,505**	**19,990,000**	**21,725,098**	**-**	**58,279,038**	**61,998,843**
TOTAL LIABILITIES	**6,347,084**	**17,557,371**	**8,834,324**	**792,212**	**1,517,121**	**22,701,481**	**30,593,420**	**697,630**	**89,040,643**	**98,294,160**
DEFERRED INFLOWS OF RESOURCES										
Gain on Refunding	-	-	61,610	-	-	631,963	-	-	693,573	888,196
NET POSITION										
Net Investment in Capital Assets	34,729,388	112,374,260	4,206,553	2,774,923	-	(293,376)	-	431,207	154,222,955	156,594,212
Restricted - Debt Service	-	-	2,048,201	-	-	2,339,676	-	-	4,387,877	4,311,482
Restricted - Reserve & Contingency	-	-	-	-	-	284,610	-	-	284,610	284,610
Unrestricted (Deficit)	12,726,832	47,628,053	6,236,983	386,554	163,330	11,265,112	1,807,580	2,290,609	82,505,048	66,295,664
TOTAL NET POSITION	**$ 47,456,220**	**$ 160,002,313**	**$ 12,491,737**	**$ 3,161,477**	**$ 163,330**	**$ 13,596,022**	**$ 1,807,580**	**$ 2,721,816**	**$ 241,400,490**	**$ 227,485,968**

MICHIGAN PUBLIC POWER AGENCY

STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

December 31, 2023

(With Comparative Totals for December 31, 2022)

	CAMPBELL # 3	BELLE RIVER	COMBUSTION TURBINE	TRANSMISSION PROJECT	LANDFILL PROJECT	AFEC PROJECT	ENERGY SVCS PROJECT	GENERAL FUND	Totals 2023	Totals 2022
OPERATING REVENUES										
Gross Sales	$ 10,580,793	$ 71,225,390	$ 8,735,153	$ 1,164,873	$ 12,514,337	$ 12,066,968	$ 139,723,287	$ -	$ 256,010,798	$ 296,414,752
Jt Zone Transmission Revenue	-	-	-	5,798,705	-	-	-	-	5,798,705	5,810,239
Jt Zone Transmission Distribution	-	-	-	(5,754,180)	-	-	-	-	(5,754,180)	(5,766,331)
Other	-	-	-	-	-	-	-	3,823,022	3,823,022	3,094,011
Total Operating Revenues	**10,580,793**	**71,225,390**	**8,735,153**	**1,209,398**	**12,514,337**	**12,066,968**	**139,723,287**	**3,823,022**	**259,878,345**	**299,552,671**
OPERATING EXPENSES										
Cost of Energy - Produced	8,048,907	42,833,315	2,139,880	-	-	7,218,415	-	-	60,240,517	79,784,901
Cost of Energy & Capacity - Purchased	-	-	-	-	13,264,924	839,144	109,253,021	-	123,357,089	142,378,192
Energy Market Overhead Fees	42,159	224,996	7,689	-	-	-	814,916	-	1,089,760	1,417,629
Other	-	-	-	-	(892,288)	-	949,239	-	56,951	(1,178,550)
Transmission	1,482,746	4,263,786	1,071,751	997,540	-	648,303	26,942,643	-	35,406,769	37,614,713
Administrative & General	506,982	4,471,792	1,202,543	211,857	141,701	410,099	1,763,468	3,684,679	12,393,121	11,584,348
Depreciation	2,649,413	12,276,895	1,054,003	63,375	-	1,023,540	-	49,850	17,117,076	17,348,882
Total Operating Expenses	**12,730,207**	**64,070,784**	**5,475,866**	**1,272,772**	**12,514,337**	**10,139,501**	**139,723,287**	**3,734,529**	**249,661,283**	**288,950,115**
Operating Income (Loss)	**(2,149,414)**	**7,154,606**	**3,259,287**	**(63,375)**	**-**	**1,927,467**	**-**	**88,493**	**10,217,062**	**10,602,556**
NONOPERATING REVENUES (EXPENSES)										
Interest Cost Incurred	-	-	(107,344)	-	-	(352,656)	-	-	(460,000)	(526,360)
Amortization of Financing-Related Costs	-	-	40,617	-	-	154,006	-	-	194,623	220,226
Investment Income	298,542	1,008,316	200,241	28,585	60,425	424,829	910,750	101,250	3,032,938	566,834
Net Change in Fair Value of Investments	212,970	185,259	33,808	8,001	24,429	88,418	272,750	46,579	872,214	(1,191,154)
Prepaid Rent Income	-	-	-	-	-	-	-	58,556	58,556	66,192
Miscellaneous	-	-	-	-	-	-	-	(870)	(870)	-
Total Nonoperating Revenues (Expenses)	**511,512**	**1,193,575**	**167,322**	**36,586**	**84,854**	**314,597**	**1,183,500**	**205,515**	**3,697,461**	**(864,262)**
CHANGE IN NET POSITION	**$ (1,637,902)**	**$ 8,348,181**	**$ 3,426,609**	**$ (26,789)**	**$ 84,854**	**$ 2,242,064**	**$ 1,183,500**	**$ 294,008**	**$ 13,914,522**	**$ 9,738,294**
CHANGE IN NET POSTION	**$ (1,637,902)**	**$ 8,348,181**	**$ 3,426,609**	**$ (26,789)**	**$ 84,854**	**$ 2,242,064**	**$ 1,183,500**	**$ 294,008**	**$ 13,914,522**	**$ 9,738,294**
NET POSITION - BEGINNING OF YEAR	**49,094,121**	**151,654,131**	**9,065,129**	**3,188,266**	**78,476**	**11,353,957**	**624,080**	**2,427,808**	**227,485,968**	**217,747,674**
NET POSITION - END OF YEAR	**$ 47,456,220**	**$ 160,002,313**	**$ 12,491,737**	**$ 3,161,477**	**$ 163,330**	**$ 13,596,022**	**$ 1,807,580**	**$ 2,721,816**	**$ 241,400,490**	**$ 227,485,968**

MICHIGAN PUBLIC POWER AGENCY

STATEMENT OF CASH FLOWS
Year Ended December 31, 2023
(With Comparative Totals for December 31, 2022)

	CAMPBELL # 3	BELLE RIVER	COMBUSTION TURBINE	TRANSMISSION PROJECT	LANDFILL PROJECT	AFEC PROJECT	ENERGY SVCS PROJECT	GENERAL FUND	Totals 2023	Totals 2022
CASH FLOWS FROM OPERATING ACTIVITIES										
Received from Customers	$ 10,564,870	$ 72,205,433	$ 9,085,493	$ 1,267,689	$ 13,406,625	$ 14,290,362	$ 141,909,604	$ 3,927,224	$ 266,657,300	$ 297,042,423
Paid to Suppliers for Goods and Services	(9,872,164)	(51,780,835)	(4,427,755)	(1,226,025)	(13,434,415)	(10,163,338)	(142,758,894)	(2,526,268)	(236,189,694)	(265,513,014)
Paid to Employees for Services	(244,205)	(361,913)	(260,367)	(64,044)	(104,252)	(217,006)	(904,443)	(1,466,055)	(3,622,286)	(3,394,277)
Net Cash Flows From (Used in) Operating Activities	**448,501**	**20,062,685**	**4,397,371**	**(22,380)**	**(132,042)**	**3,910,018**	**(1,753,733)**	**(65,098)**	**26,845,321**	**28,135,132**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES										
Acquisition and Construction of Utility Plant	(497,240)	(9,221,179)	(109,773)	-	-	(45,237)	-	-	(9,873,428)	(17,141,191)
Principal Payment on Revenue Bonds	-	-	(2,010,000)	-	-	(2,290,000)	-	-	(4,300,000)	(4,040,000)
Interest Paid on Revenue Bonds	-	-	(120,710)	-	-	(370,747)	-	-	(491,457)	(460,576)
Other	-	-	-	-	-	-	-	1,518	1,518	42,111
Net Cash Flows From (Used in) Capital and Related Financing Activities	**(497,240)**	**(9,221,179)**	**(2,240,483)**	-	-	**(2,705,984)**	-	**1,518**	**(14,663,368)**	**(21,599,656)**
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES										
Working Capital Contributions	-	-	-	-	-	-	448,086	(578,067)	(129,981)	5,875,799
CASH FLOWS FROM INVESTING ACTIVITIES										
Investments Purchased	(5,344,646)	(10,676,342)	(1,565,688)	(246,595)	(523,776)	(3,448,623)	(8,401,035)	(878,140)	(31,084,846)	(32,986,947)
Investments Sold	7,484,324	8,679,258	1,492,064	323,363	932,322	3,747,087	11,022,000	1,748,725	35,429,143	13,617,355
Investment Income	298,890	964,565	194,774	28,107	60,473	414,784	894,483	102,135	2,958,210	457,250
Net Cash Flows From Investing Activities	**2,438,568**	**(1,032,520)**	**121,150**	**104,874**	**469,019**	**713,248**	**3,515,448**	**972,719**	**7,302,507**	**(18,912,342)**
Net Change in Restricted & Unrestricted Cash and Cash Equivalents	**2,389,829**	**9,808,986**	**2,278,038**	**82,494**	**336,977**	**1,917,281**	**2,209,801**	**331,073**	**19,354,479**	**(6,501,067)**
RESTRICTED & UNRESTRICTED CASH AND CASH EQUIVALENTS - BEGINNING OF YEAR	**3,753,265**	**14,279,554**	**3,777,208**	**421,183**	**791,063**	**7,905,709**	**16,063,571**	**1,185,727**	**48,177,280**	**54,678,347**
RESTRICTED & UNRESTRICTED CASH AND CASH EQUIVALENTS - END OF YEAR	**$ 6,143,094**	**$ 24,088,540**	**$ 6,055,246**	**$ 503,677**	**$ 1,128,039**	**$ 9,822,991**	**$ 18,273,373**	**$ 1,516,800**	**$ 67,531,759**	**$ 48,177,280**
RECONCILIATION OF OPERATING INCOME (LOSS) TO NET CASH FLOWS FROM OPERATING ACTIVITIES										
Operating Income (Loss)	(2,149,414)	7,154,606	3,259,287	(63,375)	-	1,927,467	-	88,493	10,217,062	10,602,555
Adjustments to Reconcile Operating Income (Loss) to Net Cash Provided by (Used in) Operating Activities										
Depreciation	2,649,413	12,276,895	1,054,003	63,375	-	1,023,540	-	49,850	17,117,076	17,348,882
Changes in Assets and Liabilities										
Accounts Receivable	(15,922)	1,016,652	350,339	58,292	-	2,223,394	2,202,526	104,199	5,939,480	(3,919,191)
Fuel Inventory	(109,252)	-	(87,495)	-	-	-	-	-	(196,747)	(116,390)
Materials and Supplies Inventory	-	(504,897)	(17,667)	-	-	-	-	-	(522,564)	(1,078,586)
Prepaid Items and Deposits	-	-	-	-	-	-	-	(138,900)	(138,900)	(355,122)
Accounts Payable and Accrued Expense	73,674	119,429	(161,096)	(80,672)	(132,042)	(1,264,384)	(3,956,259)	(168,740)	(5,570,089)	5,652,984
NET CASH FLOWS FROM OPERATING ACTIVITIES	**448,501**	**20,062,685**	**4,397,371**	**(22,380)**	**(132,042)**	**3,910,018**	**(1,753,733)**	**(65,098)**	**26,845,321**	**28,135,132**
RECONCILIATION OF RESTRICTED & UNRESTRICTED CASH AND CASH EQUIVALENTS TO THE STATEMENT OF NET POSITION										
Cash & Cash Equivalents	5,093,094	24,088,540	3,951,650	503,677	1,128,039	7,022,376	18,273,373	1,516,800	61,577,549	42,468,008
O&M/Fuel Reserve	1,050,000	-	-	-	-	-	-	-	1,050,000	1,050,000
Restricted Cash - Debt Service	-	-	2,103,596	-	-	2,516,004	-	-	4,619,600	4,574,663
Restricted Cash - Other	-	-	-	-	-	284,610	-	-	284,610	284,610
TOTAL RESTRICTED & UNRESTRICTED CASH AND CASH EQUIVALENTS	**$ 6,143,094**	**$ 24,088,540**	**$ 6,055,246**	**$ 503,677**	**$ 1,128,039**	**$ 9,822,991**	**$ 18,273,373**	**$ 1,516,800**	**$ 67,531,759**	**$ 48,377,280**
NONCASH INVESTING, CAPITAL AND RELATED FINANCING ACTIVITIES										
Net Change in Fair Value of Investments	$ 212,970	$ 185,259	$ 33,808	$ 8,001	$ 24,429	$ 88,418	$ 272,750	$ 46,579	$ 872,214	$ (1,191,154)

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NOTE 1 – NATURE OF OPERATIONS

Michigan Public Power Agency (MPPA) is a public body politic and corporate of the State of Michigan created in 1978 under Act 448 of the Public Acts of Michigan, 1976, as amended. MPPA was formed to undertake the planning, financing, development, acquisition, construction, improvement, operation, and maintenance of projects to supply electric power and energy for the present or future needs of its members. Each MPPA member is a municipal corporation organized under the laws of the State of Michigan and owns and operates a municipal electric system. Of MPPA's 22 members, 10 are participants in the Campbell #3 Project, 11 in the Belle River Project, five in the Combustion Turbine Project, 13 in the Transmission Project, 21 in the Energy Services Project, 13 in the AFEC Project, and 14 in the Landfill Renewable Energy Project.

The financial statements of the utility are presented in conformity with accounting principles generally accepted in the United States of America as applicable to governmental units.

Basis of Presentation

The financial activities of MPPA are recorded in separate proprietary funds described as follows:

Project Funds

The Campbell #3, Belle River, Combustion Turbine, Energy Services, Landfill Renewable Energy, AFEC, and Transmission Funds account for the financing and operation of MPPA's interest in the respective projects, whereby costs are recovered through participant charges. The accounts of these Funds are maintained in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission. Enterprise funds are accounted for on an accrual basis with a flow of economic resources measurement focus.

General Fund

The General Fund accounts for financing, through participant charges, the general and administrative activities of MPPA not related to any specific electric power supply project.

Net Position

As required by GASB Statement No. 34, net position is classified into three components – net investment in capital assets; restricted; and unrestricted. These classifications are defined as follows:

- *Net investment in capital assets* – This component of net position consists of capital assets, including restricted capital assets, net of accumulated depreciation and reduced by the outstanding balances of any bonds, mortgages, notes, obligations, or other borrowings that are attributable to the acquisition, construction, or improvement of those assets. If there are significant unspent related debt proceeds at year end, the portion of the debt attributable to the unspent proceeds is not included in the calculation of invested in capital assets, net of related debt. Rather, that portion of the debt is included in the same net position component as the unspent proceeds.
- *Restricted* – This component of net position consists of constraints placed on net position use through external constraints imposed by creditors (such as through debt covenants), grantors, contributors, or laws or regulations of other governments or constraints imposed by law through constitutional provisions or enabling legislation.

NOTE 1 – NATURE OF OPERATIONS (cont.)

- *Unrestricted* – This component of net position consists of net position that does not meet the definition of "restricted" or "net investment in capital assets".

When both restricted and unrestricted resources are available for use, it is MPPA's policy to use restricted resources first, then unrestricted resources as they are needed.

The basic financial statements include certain prior year summarized comparative information in total but not at the level of detail required for a presentation in conformity with generally accepted accounting principles. Accordingly, such information should be read in conjunction with MPPA's financial statements for the year ended December 31, 2022, from which the summarized information was derived.

Budgetary Accounting

The Board of Commissioners of MPPA adopts an operating budget each year for all funds, on the same basis of accounting used to reflect actual revenues and expenses in the financial statements. The CEO & General Manager exercises budgetary control.

Use of Estimates

Preparation of financial statements in conformity with generally accepted accounting principles 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 financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from those estimates.

Operating Revenues

MPPA distinguishes operating revenues and expenses from non-operating items. Operating revenues and expenses generally result from providing services and producing and delivering goods with MPPA's principal ongoing operations. The principal operating revenues of MPPA are derived from charges to members for sales and services. Operating expenses for MPPA include the cost of sales and services, administrative expenses, and depreciation on capital assets. All revenues and expenses not meeting this definition are reported as non-operating revenues and expenses.

Prepaid Expenses and Deposits

Prepayments include costs of expenses paid in advance for which the future benefits have yet to be realized. Prepayments and Deposits are for a) working capital advances to MPPA's majority-owner operators of its power plants and b) other general and administrative operating costs.

Prepaid Expenses and deposit balances were as follows at December 31:

	2023
Majority Owner Operator	$5,421,265
Other General Operating Items	617,419
Total Prepaid and Deposits	**$6,038,684**

NOTE 1 – NATURE OF OPERATIONS (cont.)

Accounts Receivable

Accounts receivables are stated at the net invoice amount billed to MPPA's members. Any outstanding receivables are generally collected in full within 15 days of being invoiced. As such, there has been no allowance for doubtful accounts recorded.

Accounts Payable and Accrued Expenses

MPPA pays its plant operators and other third-party energy suppliers according to the terms stated within the individual contracts. Accrued expenses are those expenses related to compensation and benefits that have been earned but not yet paid and are reflected within the balances of the General Fund.

Utility Plant

Additions to and replacements of utility plant are recorded at original cost including any capitalized interest for borrowed funds used to construct the facilities. The Agency will align with the majority owner depreciation schedules when it makes sense to do so. Otherwise, depreciation is recorded using the straight-line method from 3 to 37.5 years.

Inventories

Fuel inventories for the Campbell #3 Project and the Combustion Turbine Project are stated at average cost. As a result of updated information from the operator, DTE Energy, the Belle River fuel inventory has been adjusted to its original cost of acquisition. The materials and supplies inventory for the Belle River Project is controlled by the operator and is stated at average cost. For the Combustion Turbine Project, the materials and supplies inventory are stated at actual cost.

Cash Equivalents

For the purposes of the Statement of Cash Flows, cash equivalents are cash and investments having an initial maturity of three months or less.

Unamortized Premiums and Discounts

Bond premiums and discounts are amortized over the life of the bonds based on the effective interest method. Unamortized premiums and discounts are reported net with Revenue Bonds Payable.

Deferred Outflows of Resources

A deferred outflow of resources represents a consumption of net position that applies to a future period and will not be recognized as an outflow of resources (expense) until that future time. In accordance with GASB 83, MPPA will also report certain asset retirement obligations as deferred outflows of resources and amortize those obligations over the remaining life of the related assets. See Note 12 for additional information about Asset Retirement Obligations.

NOTE 1 – NATURE OF OPERATIONS (cont.)

Deferred Inflows of Resources

A deferred inflow of resources represents an acquisition of net position that applies to a future period and therefore will not be recognized as an inflow of resources (revenue) until that future time. Gains on advance refundings are classified as deferred inflows of resources and amortized using the effective interest rate method over the repayment period of the affiliated debt.

Taxes

MPPA is exempt from state and federal income taxes.

Compensated Absences

Under terms of employment, employees earn paid time off according to years of service. Employees can accumulate up to thirty days of personal leave. Employees are paid for unused personal leave upon separation of service. MPPA self-funds short-term disability benefits from the 11th to the 30th day of a covered absence. A separate disability insurance policy compensates employees for covered absences that extend beyond the 30th day. These benefits are reported as accrued expenses under the General Fund on the Statement of Net Position.

Comparative Data

Certain amounts presented in the prior year comparative data may have been reclassified in order to be consistent with the current year's presentation.

Member Deposits

Members provide cash to the individual projects to meet working capital and collateral requirements per their contracts. Such amounts are due back to members at the end of the contract.

NOTE 2 – EFFECT OF NEW ACCOUNTING STANDARDS ON CURRENT PERIOD FINANCIAL STATEMENTS

GASB has issued Statement No. 99, *Omnibus 2023,* Statement No. 100, *Accounting Changes and Error Corrections, an amendment of GASB Statement No. 62,* Statement No. 101, *Compensated Absences* and Statement No. 102, *Certain Risk Disclousres.* Application of these recently issued accounting pronouncements, when effective, may restate portions of these financial statements.

NOTE 3 – JOINT PROJECT OWNERSHIP AGREEMENTS

Campbell Unit #3

MPPA and Consumers Energy Company (Consumers) entered into the following agreements dated October 1, 1979, as amended, relating to Consumers' Campbell Unit #3 steam-electric generating unit, which went into commercial operation in September 1980:

The Campbell Ownership Agreement provides for MPPA to own a 4.8% undivided interest in Campbell Unit #3, for Consumers to operate Campbell Unit #3, for the sale of surplus electric capacity to Consumers, for operating costs of Campbell Unit #3 to be shared on a pro rata basis, and for MPPA to purchase an undivided ownership interest in the fuel supply for Campbell Unit #3.

The Campbell Transmission Agreement provides for MPPA to purchase a 58.06% undivided ownership interest in certain Consumers' (now METC) 345 kV transmission lines, the method of determining certain charges for utilization of the METC/(Consumers) transmission system, for the sale to METC/(Consumers) of planned excess transmission capacity, if available, and for sharing transmission line operating expenses.

The Campbell Back-Up Agreement provides for Consumers to make backup electric capacity and energy available to MPPA from its electric system reserves in the event of total or partial unavailability of capacity and energy from Campbell Unit #3, and for determination of the associated backup electric capacity and energy charges to MPPA.

MPPA entered a Power Sales Contract and a Project Support Contract with each of the 10 members who elected to participate in the Campbell #3 Project. These contracts provide for the participant to purchase from MPPA the participant's entitlement share, as defined, of the generation and transmission of the Project.

On January 30, 2013, MPPA completed financing via a private placement bond through BMO Harris Bank N.A. in the amount of $23,500,000. The funds were used to finance capital improvements to the Campbell #3 power plant and the installation of necessary environmental controls. This bond was paid in full on January 1, 2023.

Belle River Unit No. 1

On December 1, 1982, MPPA and Detroit Edison Company (Edison) entered into the following agreements, as amended, relating to Edison's Belle River Unit No. 1 steam-electric generating unit, part of a two-unit generating station, which went into commercial operation in August 1984:

The Belle River Participation Agreement provides for MPPA to purchase a 37.22% undivided ownership interest in Belle River Unit No. 1 and an undivided ownership interest in certain common and joint facilities associated with Belle River Unit No. 1, for MPPA to purchase an undivided ownership interest in the fuel supply stockpile, for Edison to operate Belle River Units No. 1 and 2, for the sharing of operating costs of both units, for the sale of surplus electric capacity and energy to Edison, and for backup electric capacity and energy from Edison's electric system reserves to be available in the event of total or partial unavailability of power and energy from Belle River. Pursuant to the reliability exchange provisions in the Agreement, MPPA is entitled to 18.61% of the electric capacity and energy from each of the Belle River Units No. 1 and 2.

NOTE 3 – JOINT PROJECT OWNERSHIP AGREEMENTS (cont.)

Belle River Unit No. 1

The Belle River Transmission Ownership and Operating Agreement with Edison (now ITC) provided for MPPA to purchase a 50.41% undivided ownership interest in certain 345 kV Transmission Lines, for ITC to operate the transmission lines, for the sharing of operating costs, and for the sale of planned excess transmission capacity to ITC, if any.

MPPA entered into the Belle River Transmission Ownership and Operating Agreement with Consumers Energy (now METC), dated December 1, 1982, as amended, which provides MPPA with a 90% undivided ownership interest in certain METC designated transmission lines, for METC to operate the transmission lines, for the sharing of operating costs.

MPPA entered a Power Sales Contract and a Project Support Contract with each of the 11 members who elected to participate in the Belle River Project. These contracts provide for the participants to purchase from MPPA their entitlement share, as defined, of generation and transmission of the Project. Each participant also shares proportionately in MPPA's sale of excess generating and transmission capacity. Each participant is obligated to pay its share of power, transmission, backup, debt service, and other project-related costs.

Combustion Turbine Project

In 2002, MPPA completed construction of a 60.5 MW (nominal nameplate rating) simple-cycle combustion turbine generating unit fueled with natural gas (the CT Project). The unit is located in Kalkaska County, Michigan. The project included construction of natural gas pipeline and metering equipment to connect to natural gas facilities, a 69kV electrical line tap and associated equipment to deliver the output of the CT Project to the transmission system, and an undivided ownership interest in certain transmission lines on the METC transmission system.

In late 2012, MPPA entered into a long-term supply agreement with ANR Pipeline Company (ANR). ANR owns and operates an existing interstate natural gas pipeline system which transports natural gas to markets located in Michigan near the plant. MPPA has established an interconnection between its facilities at the plant and the natural gas pipeline facilities of ANR to provide for the transportation of natural gas necessary to operation of the plant.

Transmission Project

In 2006, MPPA purchased an undivided ownership in certain 345kV transmission lines in the METC system. 13 members participate in this Project.

AMP Fremont Energy Center Project (AFEC)

In June 2012, MPPA completed its purchase of a 5.16% interest in a combined cycle natural gas fired electric generation facility located in Fremont, Sandusky County, Ohio. American Municipal Power, Inc. is the majority owner of this power plant and serves as the operator. 13 of MPPA's municipal members committed to power purchases under the AFEC Project.

NOTE 4 – CASH AND INVESTMENTS

MPPA adopted an investment policy, in accordance with the bond resolutions, that allows it to invest in U.S. Treasury obligations, certain federal agency securities, bonds, direct and general obligations of any state, certificates of deposit with qualified United States institutions, repurchase agreements with qualified institutions, municipal obligations, time deposits, bankers' acceptances, commercial paper, and pooled investment funds.

MPPA's investment in US Government and Agency debt obligations, Municipal Bonds and other permitted investments at year end consists of:

	Bank Value
Restricted & Unrestricted Cash and Cash Equivalents	
Checking	$ 4,210,663
Money Market Funds	63,321,096
Total Restricted & Unrestricted Cash and Cash Equivalents	**67,531,759**
Unrestricted Assets Invested	
U.S. Treasury Notes	28,887,447
Agency Notes	2,708,845
Local Government Bonds	360,768
Total Unrestricted Assets Invested	**31,957,060**
Total Cash & Investments	**$ 99,488,819**

Fair Value Measurement

MPPA categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. Investments that are measured at fair value using the net asset value per share (or its equivalent) as a practical expedient are not classified in the fair value hierarchy.

In instances, whereby inputs used to measure fair value fall into different levels in the above fair value hierarchy, fair value measurements in their entirety are categorized based on the lowest level input that is significant to the valuation. MPPA's assessment of the significance of inputs to these fair value measurements required judgement and considers factors specific to each asset or liability.

As of December 31, 2023, the following investments are recorded at fair value using the Matrix Pricing Technique:

NOTE 4 – CASH AND INVESTMENTS (cont.)

Investment	Level 1	Level 2	Level 3	Total
U.S. Treasury Notes	$ -	$ 28,887,447	$ -	$ 28,887,447
Federal Home Loan Mortgage Association Notes	-	150,100	-	150,100
Federal Farm Credit Bank Notes	-	259,641	-	259,641
Fannie Mae Mortgage Association Notes	-	1,495,704	-	1,495,704
Freddie Mac Mortgage Backed Securities	-	738,624	-	738,624
Local Government Bonds	-	360,768	-	360,768
Federal Home Loan Bank Bonds		64,776		64,776
Total Investments by Fair Value Level	**$ -**	**$ 31,957,060**	**$ -**	**$ 31,957,060**

Custodial Credit Risk

Deposits

Custodial credit risk is the risk that in the event of a financial institution failure, MPPA's deposits may not be returned to MPPA. Deposits in banks are insured by the FDIC in the amount of $250,000 for all interest-bearing accounts.

On December 31, 2023, MPPA had $62,148,466 in uninsured and uncollateralized deposits. MPPA's investment policy does not require collateralization of deposits but rather restricts the financial institutions that can be used based on the equity and market ratings of the financial institution's debt.

Investments

For an investment, custodial credit risk is the risk that, in the event of the failure of the counterparty, MPPA will not be able to recover the value of its investment or collateral securities that are in the possession of an outside party. On December 31, 2023, MPPA had $31,957,060 in investments subject to custodial credit risk. MPPA's policy is to have all investment securities held by its agent in MPPA's name.

NOTE 4 – CASH AND INVESTMENTS (cont.)

Credit Risk

Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. As of December 31, 2023, MPPA's investments were rated as follows:

Investment Type	Standard & Poor's	Moody's
US Treasury Bonds	AA+	Aaa
US Agency Securities	AA+	Aaa
Local Government Bonds	AA	Aa1
Money Market Funds	AAA	Aaa

MPPA's investment policy requires that investments be rated AA or equivalent by Standard &Poor's or Moody's. Money market funds are required to be rated AAA or equivalent by Standard & Poor's or Moody's.

Concentration of Credit Risk

Concentration of credit risk is the risk of loss attributed to the magnitude of MPPA's investment in a single issuer.

MPPA's investment policy does not limit the amount of the portfolio that can be invested in U.S. government agency securities or any one issuer of such investments. MPPA limits its investment in a single issuer of state and local debt to 33% of its total portfolio. Investments in a single issuer of money market funds are limited to 75% of its total portfolio. All other types of approved investments in a single issuer are limited to 50% of MPPA's total portfolio. MPPA does not have any investments exceeding 5% of its total portfolio.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates will adversely affect the fair value of an investment. MPPA's investment policy restricts operational funds to maturities of one year or less, reserve, and contingency funds to five years or less, and debt service reserve funds to 10 years or less.

On December 31, 2023, MPPA's investments were as follows:

		Maturity in years	
Investment Type	**Fair Value**	**Less than 1 year**	**1-5 years**
US Treasury	$ 28,887,447	$ 15,593,002	$ 13,294,445
Agency Notes	2,708,845	252,851	2,455,994
Local Government Bonds	360,768	360,768	-
Total Investments	**$ 31,957,060**	**$ 16,206,621**	**$ 15,750,439**

NOTE 5 – RESTRICTED ASSETS

MPPA's bond resolutions require the segregation of bond proceeds, establishment of various funds, and prescribe the application of MPPA's revenues. Also, it defines what type of securities MPPA may invest in. The funds established by the resolution are detailed in the Statement of Net Position. MPPA is compliant with all bond resolution funding requirements.

NOTE 6 – CHANGES IN CAPITAL ASSETS

A summary of changes in capital assets is as follows:

	Balance 01/01/2023	Additions & Reclasses	Deletions & Reclasses	Balance 12/31/2023
Capital assets:				
Building & Land	$ 2,253,900	$ 54,949	$ -	$ 2,308,849
Utility Plant in Service	646,995,654	9,489,983	(9,785,160)	646,700,477
Less: Accumulated Depreciation	(456,817,146)	(16,410,812)	9,785,160	(463,442,798)
Net Utility Plant	**$ 192,432,408**	**$ (6,865,880)**	**$ -**	**$ 185,566,528**

Campbell #3 Project

Consumers Energy ("CE") obtained regulatory approval of a settlement agreement from the Michigan Public Service Commission ("MPSC Order") on June 23, 2022. The Order was appealed by Wolverine Power Supply Cooperative. The appeal was denied by the Court of Appeals on March 23, 2023. The MPSC Order approved, among other things, accelerating the retirement by 15 years of the J.H. Campbell facility (Units 1, 2 and 3) to a date to occur on or before May 31, 2025. The authorization to early retire J.H. Campbell was tied to several other provisions but two key provisions related to replacement of the lost power supply and accounting regulatory treatment of the undepreciated rate base of the J.H Campbell facility:

1. Authorization granted to CE to purchase, and rate base the New Covert Generation Station (1,000 MW CCGT)
2. Permission for CE to recover the unrecovered book balance of J.H. Campbell facility through the Company's proposed regulatory asset treatment, with a return on capital equal to the Company's weighted average cost of capital ("WACC") through 2039.

MPPA considers this a temporary impairment in accordance with GASB 43, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries* and has continued to depreciate the asset on the same useful life as CE (see #2 above…CE will depreciate through 2039) and when the plant is officially retired, MPPA will recognize an impairment loss.

NOTE 7 – NON-CURRENT LIABILITIES

AFEC Project Revenue Bonds

The following bonds have been issued by MPPA:

Date	Purpose	Final Maturity	Interest Rates	Original Amount
Ocotber 6,2021	Refinancing of 2012 Bonds	1/1/2032	1.58%	$ 24,610,000

The following obligations are outstanding at 12/31/2023:

2021 Series A Bonds	$ 22,320,000
Less: Current Portion	(2,330,000)
Total	**$ 19,990,000**

MPPA's annual debt service requirements are collected from participating member municipalities and from transfers from the project account during the period preceding the required interest and principal payments. Debt service requirements to be collected during each of the five years following December 31, 2023, and in five-year increments thereafter to maturity, are as follows:

Year Ending December 31	Principal	Interest	Total
2024	2,330,000	352,656	2,682,656
2025	2,365,000	315,842	2,680,842
2026	2,400,000	278,475	2,678,475
2027	2,440,000	240,555	2,680,555
2028	2,475,000	202,003	2,677,003
2029-2032	10,310,000	410,247	10,720,247
Total	**$ 22,320,000**	**$ 1,799,778**	**$ 24,119,778**

NOTE 7 – NON-CURRENT LIABILITIES (cont.)

AFEC Project Revenue Bonds (cont.)

Non-Current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Revenue Bonds	$ 24,610,000	$ -	$ (2,290,000)	$ 22,320,000
Current Maturities	(2,290,000)	(40,000)	-	(2,330,000)
Total Non-Current Liabilities	**$ 22,320,000**	**$ (40,000)**	**$ (2,290,000)**	**$ 19,990,000**

Direct Placement

MPPA entered a direct placement of its debt for the AFEC 2021 Series A Refunding Revenue bonds in the amount of $24,610,000. The bonds are subject to the terms and conditions of the original bond resolution. As a covenant of the refunding, MPPA agrees to maintain $3 million in unrestricted funds in an account with the purchasing bank of the direct placement. There are no additional covenants associated with the direct placement debt or additional finance related consequences related to significant events of default, termination events or subjective acceleration clauses.

Combustion Turbine Project Revenue Bonds

The following bonds have been issued by MPPA:

Date	Purpose	Final Maturity	Interest Rate	Original Amount
October 30,2020	Refinancing of 2011 bonds	1/1/2027	1.33%	$ 12,305,000

The following obligations are outstanding at 12/31/2023:

2020 Series A Bonds	$ 8,330,000
Less: Current Portion	(2,040,000)
Total	**$ 6,290,000**

NOTE 7 – NON-CURRENT LIABILITIES (cont.)

Combustion Turbine Project Revenue Bonds (cont.)

MPPA's annual debt service requirements are collected from participating member municipalities and from transfers from the project account during the period preceding the required interest and principal payments. Debt service requirements to be collected during each of the remaining six years following December 31, 2023, are as follows:

Year Ending December 31	Principal	Interest	Total
2024	2,040,000	110,789	2,150,789
2025	2,070,000	83,657	2,153,657
2026	2,095,000	56,126	2,151,126
2027	2,125,000	28,263	2,153,263
Total	**$ 8,330,000**	**$ 278,835**	**$ 8,608,835**

Non-Current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Revenue Bonds	$ 10,340,000	$ -	(2,010,000)	$ 8,330,000
Current Maturities	(2,010,000)	(30,000)	-	(2,040,000)
Total Non-Current Liabilities	**$ 8,330,000**	**$ (30,000)**	**$ (2,010,000)**	**$ 6,290,000**

Direct Placement

MPPA entered a direct placement of its debt for the Combustion Turbine 2020 Series A Refunding Revenue bonds in the amount of $12,305,000. The bonds are subject to the terms and conditions of the original bond resolution. As a covenant of the refunding, MPPA agrees to maintain $1 million in unrestricted funds in an account with the purchasing bank of the direct placement. There are no additional covenants associated with the direct placement debt or additional finance related consequences related to significant events of default, termination events or subjective acceleration clauses.

Campbell #3 Project

Non-current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Asset Retirement Obligation	$ 4,586,626	$ 216,542	$ -	$ 4,803,167
Member Deposits	760,145	-	-	760,145
Total Non-Current Liabilities	**$ 5,346,771**	**$ 216,542**	**$ -**	**$ 5,563,312**

NOTE 7 – NON-CURRENT LIABILITIES (cont.)

Belle River Project

Non-current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Asset Retirement Obligation	$ 743,489	$ -	$ (56,366)	$ 687,123
Member Deposits	3,270,000	620,000	-	3,890,000
Total Non-Current Liabilities	**$ 4,013,489**	**$ 620,000**	**$ (56,366)**	**$ 4,577,123**

Energy Services Project

Non-current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Member Deposits	$ 21,277,011	$ 448,086	$ -	$ 21,725,098
Total Non-Current Liabilities	**$ 21,277,011**	**$ 448,086**	**$ -**	**$ 21,725,098**

Landfill Renewable Energy Project

Non-current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Member Deposits	$ 133,505	$ -	$ -	$ 133,505
Total Non-Current Liabilities	**$ 133,505**	**$ -**	**$ -**	**$ 133,505**

General Fund

Non-current Liabilities as of December 31, 2023:

	01/01/2023 Balance	Additions	Reductions	12/31/2023 Balance
Member Deposits	$ 578,067	$ -	$ (578,067)	$ -
Total Non-Current Liabilities	**$ 578,067**	**$ -**	**$ (578,067)**	**$ -**

NOTE 8 – EMPLOYEE RETIREMENT PLAN

MPPA employees are covered by a defined contribution retirement pension plan, the Michigan Public Power Agency Plan (the "Plan"), which is administered by Mission Square. MPPA makes an annual contribution based on a percentage of employee earnings on behalf of each employee. The plan follows the Standard 401(a) plan offered by Mission Square. Required contributions by MPPA are 15% of employee salaries. Employees do not make contributions to the Plan. The contribution requirements are established and can be amended by the MPPA Board of Commissioners. Total contributions to the plan by MPPA for the years ended December 31, 2023, 2022, and 2021 were approximately $414,600, $402,399, and $379,500, respectively.

NOTE 9 – CONTRACTS AND COMMITMENTS

Contract with Consumers Energy

MPPA contracted with Consumers to purchase fuel coal to maintain a stockpile level of 13,708 wet tons for the Campbell Unit #3 plant for the 2023 calendar year. The coal is purchased at the prevailing market price at the time of delivery. MPPA also purchased an additional stockpile of coal as a substitute for its proportionate interest in the materials and supply inventory at Campbell Unit #3. This stockpile is maintained at a level to approximate MPPA's ownership interest in the materials and supply inventory at the Campbell plant.

Power Purchase Agreements

The Agency has entered into long-term contracts for the purchase of capacity and energy to meet the anticipated load requirements of its members.

NOTE 10 – RISK MANAGEMENT

MPPA is exposed to various risks of loss related to torts; theft of, damage to, or destruction of assets; errors and omissions; workers' compensation; and health care of its employees. These risks are covered through the purchase of commercial insurance, with minimal deductibles.

There have been no claims in any of the past two years. MPPA is committed to maintaining adequate amounts of coverage to insure against these risks.

NOTE 11 – CONCENTRATION OF RISK

Credit risk represents the risk of loss that would occur if customers do not meet their financial obligations to MPPA. Concentration of risk occurs when significant customers possess similar characteristics that would cause their ability to meet contractual obligations to be affected by the same events.

MPPA has one member who is considered a significant customer that accounted for $61.7 million (23.5%) of MPPA gross revenues in 2023.

NOTE 12 – BOND COVENANT DISCLOSURES

Combustion Turbine Project

Compliance with Funding Requirements

Debt Service Coverage

		2023
Gross Operating Revenues	$	8,735,153
Investment Income		200,241
Gross Defined Revenues		8,935,394
Operating Expenses		5,475,866
Less: Depreciation		(1,054,003)
Gross Defined Expenses		4,421,863
Net Defined Earnings	$	4,513,531
Debt Service (Principal, Interest, Reserve Contribution)		2,150,789
Required Revenues (1.1x Debt Service)		2,365,868
Revenues in Excess of Coverage Requirements	**$**	**2,147,663**

All project revenues net of specified operating expenses are pledged as security of the above revenue bonds until the bonds are retired.

NOTE 12 – BOND COVENANT DISCLOSURES (cont.)

AFEC Project

Compliance with Funding Requirements

Debt Service Coverage

		2023
Gross Operating Revenues	$	12,066,968
Other Revenues		424,829
Gross Defined Revenues		12,491,797
Operating Expenses		10,139,501
Less: Depreciation		(1,023,540)
Gross Defined Expenses		9,115,961
Net Defined Earnings	$	3,375,836
Debt Service (Principal, Interest, Reserve Contribution)		2,682,656
Required Revenues (1.1x Debt Service)		2,950,922
Revenues in Excess of Coverage Requirements	**$**	**424,915**

All project revenues net of specified operating expenses are pledged as security of the above revenue bonds until the bonds are retired.

NOTE 13 – ASSET RETIREMENT OBLIGATIONS (cont.)

MPPA follows GASB Statement 83 *Certain Asset Retirement Obligations*, which addresses financial accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets that are incurred upon the acquisition, construction, development, or normal operation of the assets. MPPA's asset retirement obligations consist primarily of costs associated with the closure of ash and scrubber ponds at MPPA's jointly owned plants, of which, MPPA owns a minority share. Per GASB 83, asset retirement obligations are recognized in the period in which they are incurred if a reasonable estimate of fair value can be made. The asset retirement obligations are accreted to their present value at the end of each reporting period. The associated estimated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depreciated over their useful life. MPPA uses information from DTE and Consumers Energy to estimate the cash flows to determine the obligation.

Balances as of December 31, 2023, are as follows:

Asset Retirement Obligations		Belle River	Campbell #3	Total
Opening Balance		$743,489	$4,586,626	**$5,330,115**
Accretion and Adjustments	$	(56,366)	$216,542	**$160,175**
Ending Balance		**$687,123**	**$4,803,167**	**$5,490,290**

MPPA's ownership percentage in the Belle River Project and Campbell #3 Project is 18.61% and 4.8%, respectively.

SUPPLEMENTAL INFORMATION

MICHIGAN PUBLIC POWER AGENCY
CAMPBELL #3 PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Energy	$ 2,909,206	$ 2,816,268	$ 92,938	$ 3,800,458
Transmission	1,482,746	1,892,984	(410,238)	1,527,847
Fuel	6,188,841	7,522,142	(1,333,301)	6,505,971
TOTAL OPERATING REVENUE	**10,580,793**	**12,231,394**	**(1,650,601)**	**11,834,276**
OPERATING EXPENSE				
PRODUCTION				
Fuel	6,188,841	7,522,142	(1,333,301)	6,505,971
Operations & Maintenance	1,860,066	1,651,680	208,386	2,036,460
MISO Market Overhead Fee	42,159	40,000	2,159	42,689
Total Operations & Maintenance Expense	8,091,066	9,213,822	(1,122,756)	8,585,120
TRANSMISSION				
Operations & Maintenance	348,663	750,137	(401,474)	502,728
Utilization Charge	1,134,083	1,142,847	(8,764)	1,025,119
Total Tranmission Expense	1,482,746	1,892,984	(410,238)	1,527,847
ADMINISTRATIVE & GENERAL				
CECo	36,894	225,000	(188,106)	78,901
MPPA				
Salaries and Benefits	244,205	267,406	(23,201)	293,819
Outside Services	178,302	80,730	97,572	76,435
All Other A & G	47,581	51,452	(3,871)	72,153
Total Administrative & General Expense	506,982	624,588	(117,606)	521,308
DEPRECIATION	2,649,413	14,956,680	(12,307,267)	2,521,025
TOTAL OPERATING EXPENSE	**12,730,207**	**26,688,074**	**(13,957,867)**	**13,155,300**
OPERATING INCOME (LOSS)	**(2,149,414)**	**(14,456,680)**	**12,307,266**	**(1,321,024)**
OTHER REVENUE (EXPENSE)				
Interest Income	298,542	110,000	188,542	97,081
Net Change in Fair Value of Investments	212,970	-	212,970	(385,189)
TOTAL OTHER REVENUE (EXPENSE)	**511,512**	**110,000**	**401,512**	**(288,108)**
CHANGE IN NET POSITION	**$ (1,637,902)**	**$ (14,346,680)**	**$ 12,708,778**	**$ (1,609,132)**

MICHIGAN PUBLIC POWER AGENCY
BELLE RIVER PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Energy	$ 34,543,028	$ 42,596,975	$ (8,053,947)	$ 47,346,852
Transmission	4,553,899	5,572,955	(1,019,056)	6,043,019
Fuel	32,128,463	33,231,758	(1,103,295)	35,225,256
TOTAL OPERATING REVENUE	**71,225,390**	**81,401,688**	**(10,176,298)**	**88,615,127**
OPERATING EXPENSE				
PRODUCTION				
Fuel	32,128,463	33,231,758	(1,103,295)	35,225,256
Operations & Maintenance	10,668,243	18,555,468	(7,887,225)	22,146,192
Reactive Revenue Distribution	36,609	(490,000)	526,609	(505,985)
MISO Market Overhead Fee	224,996	200,000	24,996	209,184
Total Operations & Maintenance Expense	43,058,311	51,497,226	(8,438,915)	57,074,647
TRANSMISSION				
Operations & Maintenance	2,171,844	2,927,778	(755,934)	2,842,630
Utilization Charge	7,456,154	7,386,449	69,705	6,638,490
ITC Revenue Distribution	(5,364,212)	(4,741,272)	(622,940)	(3,745,682)
Total Transmission Expense	4,263,786	5,572,955	(1,309,169)	5,735,438
ADMINISTRATIVE & GENERAL				
DECo	3,442,851	3,772,033	(329,182)	3,389,087
ITC	288,506	320,000	(31,494)	304,242
MPPA				
Salaries & Benefits	361,913	376,623	(14,710)	424,206
Outside Services	315,019	361,649	(46,630)	186,201
All Other A & G	63,503	69,702	(6,199)	101,306
Total Administrative & General Expense	4,471,792	4,900,007	(428,215)	4,405,042
DEPRECIATION	12,276,895	13,396,028	(1,119,133)	12,306,248
TOTAL OPERATING EXPENSE	**64,070,784**	**75,366,216**	**(11,295,432)**	**79,521,375**
OPERATING INCOME (LOSS)	**7,154,606**	**6,035,472**	**1,119,134**	**9,093,752**
OTHER REVENUE (EXPENSE)				
Interest Income	1,008,316	100,000	908,316	123,640
Net Change in Fair Value of Investments	185,259	-	185,259	(250,404)
TOTAL OTHER REVENUE (EXPENSE)	**1,193,575**	**100,000**	**1,093,575**	**(126,764)**
CHANGE IN NET POSITION	**$ 8,348,181**	**$ 6,135,472**	**$ 2,212,709**	**$ 8,966,988**

MICHIGAN PUBLIC POWER AGENCY
COMBUSTION TURBINE PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Energy	$ 6,002,445	$ 5,529,757	$ 472,688	$ 3,806,773
Transmission	1,382,317	1,915,342	(533,025)	1,609,925
Fuel	1,350,391	3,866,721	(2,516,330)	2,963,361
TOTAL OPERATING REVENUE	**8,735,153**	**11,311,820**	**(2,576,667)**	**8,380,059**
OPERATING EXPENSE				
Production				
Fuel	1,350,391	3,866,721	(2,516,330)	2,963,361
Operations & Maintenance	789,489	810,419	(20,930)	723,705
MISO Market Overhead Fee	7,689	15,000	(7,311)	14,058
Total Operations & Maintenance Expense	2,147,569	4,692,140	(2,544,571)	3,701,124
TRANSMISSION				
Operations & Maintenance	1,071,751	1,292,518	(220,767)	1,279,134
ADMINISTRATIVE & GENERAL				
Traverse City	486,574	445,500	41,074	462,501
MPPA				
Salaries & Benefits	260,367	277,107	(16,740)	261,584
Outside Services	224,547	78,568	145,979	90,094
All Other A & G	231,055	212,697	18,358	208,101
Total Administrative & General Expense	1,202,543	1,013,872	188,671	1,022,280
DEPRECIATION	1,054,003	1,107,840	(53,837)	1,003,956
TOTAL OPERATING EXPENSE	**5,475,866**	**8,106,370**	**(2,630,504)**	**7,006,494**
OPERATING INCOME (LOSS)	**3,259,287**	**3,205,450**	**53,837**	**1,373,565**
OTHER REVENUE (EXPENSE)				
Interest Income	200,241	24,000	176,241	47,838
Amortization	40,617	40,617	-	50,419
Interest Expense	(107,344)	(110,789)	3,445	(137,522)
Net Change in Fair Value of Investments	33,808	-	33,808	(41,631)
TOTAL OTHER REVENUE (EXPENSE)	**167,322**	**(46,172)**	**213,494**	**(80,896)**
CHANGE IN NET POSITION	**$ 3,426,609**	**$ 3,159,278**	**$ 267,331**	**$ 1,292,669**

MICHIGAN PUBLIC POWER AGENCY
TRANSMISSION PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Transmission Revenue	$ 1,164,872	$ 1,272,582	$ (107,710)	$ 1,260,257
Joint Zone Transmission Revenue	5,798,705	5,956,661	(157,956)	5,810,239
Joint Zone Transmission Distribution	(5,754,180)	(5,912,171)	157,991	(5,766,331)
TOTAL OPERATING REVENUE	**1,209,397**	**1,317,072**	**(107,675)**	**1,304,165**
OPERATING EXPENSE				
TRANSMISSION				
Operations & Maintenance	966,340	1,163,186	(196,846)	1,151,219
Joint Zone Operations & Maintenance	31,200	31,200	-	31,200
Total Transmission Expense	997,540	1,194,386	(196,846)	1,182,419
ADMINISTRATIVE & GENERAL				
MPPA				
Salaries & Benefits	64,058	75,577	(11,519)	79,718
Outside Services	130,931	28,987	101,944	17,366
All Other A & G	16,868	18,122	(1,254)	24,662
Total Administrative & General Expense	211,857	122,686	89,171	121,746
DEPRECIATION	63,375	63,375	-	63,375
TOTAL OPERATING EXPENSE	**1,272,772**	**1,380,447**	**(107,675)**	**1,367,540**
OPERATING INCOME (LOSS)	**(63,375)**	**(63,375)**	**-**	**(63,375)**
OTHER REVENUE (EXPENSE)				
Interest Income	28,585	3,600	24,985	5,983
Net Change in Fair Value of Investments	8,001	-	8,001	(9,248)
TOTAL OTHER REVENUE (EXPENSE)	**36,586**	**3,600**	**32,986**	**(3,265)**
CHANGE IN NET POSITION	**$ (26,789)**	**$ (59,775)**	**$ 32,986**	**$ (66,640)**

MICHIGAN PUBLIC POWER AGENCY
LANDFILL PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Energy	$ 13,406,625	$ 15,452,009	$ (2,045,384)	$ 13,828,056
Sale of RECs	(892,288)	(638,148)	(254,140)	(902,957)
TOTAL OPERATING REVENUE	**12,514,337**	**14,813,861**	**(2,299,524)**	**12,925,099**
OPERATING EXPENSE				
PURCHASED POWER				
Energy	13,264,924	15,292,768	(2,027,844)	13,664,471
REC Disbursement	(892,288)	(638,148)	(254,140)	(902,957)
Total Purchased Power	12,372,636	14,654,620	(2,281,984)	12,761,514
ADMINISTRATIVE & GENERAL				
MPPA				
Salaries & Benefits	104,252	117,489	(13,237)	114,807
Outside Services	15,847	19,342	(3,495)	19,320
All Other A & G	21,602	22,410	(808)	29,458
Total Administrative & General Expense	141,701	159,241	(17,540)	163,585
TOTAL OPERATING EXPENSE	**12,514,337**	**14,813,861**	**(2,299,524)**	**12,925,099**
OPERATING INCOME (LOSS)	-	-	-	-
OTHER REVENUE (EXPENSE)				
Interest Income	60,425	9,000	51,425	12,580
Net Change in Fair Value of Investments	24,429	-	24,429	(26,468)
TOTAL OTHER REVENUE (EXPENSE)	**84,854**	**9,000**	**75,854**	**(13,888)**
CHANGE IN NET POSITION	**$ 84,854**	**$ 9,000**	**$ 75,854**	**$ (13,888)**

MICHIGAN PUBLIC POWER AGENCY
AFEC PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Energy & Capacity	$ 12,066,968	$ 15,004,475	$ (2,937,507)	$ 15,018,990
TOTAL OPERATING REVENUE	**12,066,968**	**15,004,475**	**(2,937,507)**	**15,018,990**
OPERATING EXPENSE				
PRODUCTION				
Fuel	5,040,629	7,653,992	(2,613,363)	8,727,650
Fixed Operations & Maintenance	1,819,081	1,819,083	(2)	1,544,006
Variable Operations & Maintenance	358,705	384,522	(25,817)	418,285
PJM Replacement Power	155,428	200,000	(44,572)	536,325
Reactive Revenue Distribution	(110,159)	(110,159)	-	(110,159)
Capacity Credit	(778,389)	(518,283)	(260,106)	(1,256,419)
MISO Capacity Purchase	1,572,264	1,572,508	(244)	1,522,500
Total Operations & Maintenance Expense	8,057,559	11,001,663	(2,944,104)	11,382,188
TRANSMISSION				
LMP Price Differential	648,303	585,567	62,736	176,330
ADMINISTRATIVE & GENERAL				
AMP	105,609	113,210	(7,601)	127,687
MPPA				
Salaries and Benefits	217,006	252,539	(35,533)	261,113
Outside Services	42,827	52,454	(9,627)	53,644
All Other A & G	44,657	48,042	(3,385)	67,321
Total Administrative & General Expense	410,099	466,245	(56,146)	509,765
DEPRECIATION	1,023,540	862,000	161,540	1,400,592
TOTAL OPERATING EXPENSE	**10,139,501**	**12,915,475**	**(2,775,974)**	**13,468,875**
OPERATING INCOME (LOSS)	**1,927,467**	**2,089,000**	**(161,533)**	**1,550,115**
OTHER REVENUE (EXPENSE)				
Interest Income	424,829	52,000	372,829	84,886
Amortization	154,006	154,006	-	169,807
Interest Expense	(352,656)	(352,656)	-	(388,838)
Net Change in Fair Value of Investments	88,418	-	88,418	(106,813)
TOTAL OTHER REVENUE (EXPENSE)	**314,597**	**(146,650)**	**461,247**	**(240,958)**
CHANGE IN NET POSITION	**$ 2,242,064**	**$ 1,942,350**	**$ 299,714**	**$ 1,309,157**

MICHIGAN PUBLIC POWER AGENCY
ENERGY SERVICES PROJECT
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	UNAUDITED 2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Energy & Capacity	$ 70,783,225	$ 86,121,315	$ (15,338,090)	$ 63,220,280
Transmission	26,942,642	31,653,338	(4,710,696)	27,713,544
MISO Energy Market Sales	41,997,420	35,760,189	6,237,231	67,447,120
TOTAL OPERATING REVENUE	**139,723,287**	**153,534,842**	**(13,811,555)**	**158,380,944**
OPERATING EXPENSE				
Purchased Power				
Energy & Capacity	85,511,951	83,618,217	1,893,734	77,815,500
Energy Market Overhead Fee	814,916	1,210,000	(395,084)	1,151,698
Energy Market Purchases	23,522,736	35,760,189	(12,237,453)	50,646,562
Reactive Revenue Distribution	218,334	(300,000)	518,334	(440,588)
REC Purchases	949,239	-	949,239	(275,593)
Total Purchased Power Expense	111,017,176	120,288,406	(9,271,230)	128,897,579
TRANSMISSION				
Operations & Maintenance	25,101,204	28,297,452	(3,196,248)	24,045,878
Transmission Transfer to TSC	1,841,439	3,355,885	(1,514,446)	3,667,667
Total Transmission Expense	26,942,643	31,653,337	(4,710,694)	27,713,545
ADMINISTRATIVE & GENERAL				
MPPA				
Salaries & Benefits	904,443	967,103	(62,660)	940,070
Outside Services	696,138	447,668	248,470	589,300
All Other A & G	162,887	178,328	(15,441)	240,450
Total Administrative & General Expense	1,763,468	1,593,099	170,369	1,769,820
TOTAL OPERATING EXPENSE	**139,723,287**	**153,534,842**	**(13,811,555)**	**158,380,944**
OPERATING INCOME (LOSS)	-	-	-	-
OTHER REVENUE (EXPENSE)				
Interest Income	910,750	115,000	795,750	167,577
Net Change in Fair Value of Investments	272,750	-	272,750	(320,681)
TOTAL OTHER REVENUE (EXPENSE)	**1,183,500**	**115,000**	**1,068,500**	**(153,104)**
CHANGE IN NET POSITION	**$ 1,183,500**	**$ 115,000**	**$ 1,068,500**	**$ (153,104)**

MICHIGAN PUBLIC POWER AGENCY
GENERAL FUND
STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
DECEMBER 31, 2023 AND 2022

	2023 ACTUAL	2023 BUDGET	OVER (UNDER) 2023 BUDGET	2022 ACTUAL
OPERATING REVENUE				
Participant Dues & Assessments	$ 1,203,110	$ 1,182,470	$ 20,640	$ 973,106
Charges for Services:				
Allocated Expenses (Projects)	-	-	-	171,752
MMEA Charges	497,670	457,108	40,562	449,872
Total Committee Revenues	2,122,242	2,960,754	(838,512)	1,484,781
Miscellaneous	-	-	-	14,500
TOTAL OPERATING REVENUE	**3,823,022**	**4,600,332**	**(777,310)**	**3,094,011**
OPERATING EXPENSE				
ADMINISTRATIVE & GENERAL				
MMEA - Direct Expenses	445,590	405,028	40,562	401,872
Service Committee - Direct Expenses	2,021,442	2,856,223	(834,781)	1,404,159
Salaries & Benefits	447,205	489,280	(42,075)	502,204
Office Supplies & Expense	22,555	29,900	(7,345)	32,608
Insurance	72,548	70,994	1,554	71,184
Outside Services	123,252	173,581	(50,329)	123,355
Meeting & Travel	27,869	41,019	(13,150)	24,742
Rent & Building Maintenance	30,982	41,692	(10,710)	31,952
Miscellaneous	6,150	6,150	-	6,150
Dues & Assessments	487,086	469,138	17,948	472,577
Total Administrative & General Expense	3,684,679	4,583,005	(898,326)	3,070,802
DEPRECIATION	49,850	52,728	(2,878)	53,686
TOTAL OPERATING EXPENSE	**3,734,529**	**4,635,733**	**(901,204)**	**3,124,488**
OPERATING INCOME (LOSS)	**88,493**	**(35,401)**	**123,894**	**(30,477)**
OTHER REVENUE (EXPENSE)				
Interest Income	101,250	55,000	46,250	27,249
Net Change in Fair Value of Investments	46,579	-	46,579	(50,720)
Recognized Building Lease Income	58,555	66,192	(7,637)	66,192
Miscellaneous	(870)	-	(870)	-
TOTAL OTHER REVENUE (EXPENSE)	**205,515**	**121,192**	**84,322**	**42,721**
CHANGE IN NET POSITION	**$ 294,008**	**$ 85,791**	**$ 208,216**	**$ 12,244**

2025/2026 Base Residual Auction Report

July 30, 2024

For Public Use

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Contents

Introduction

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

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

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

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

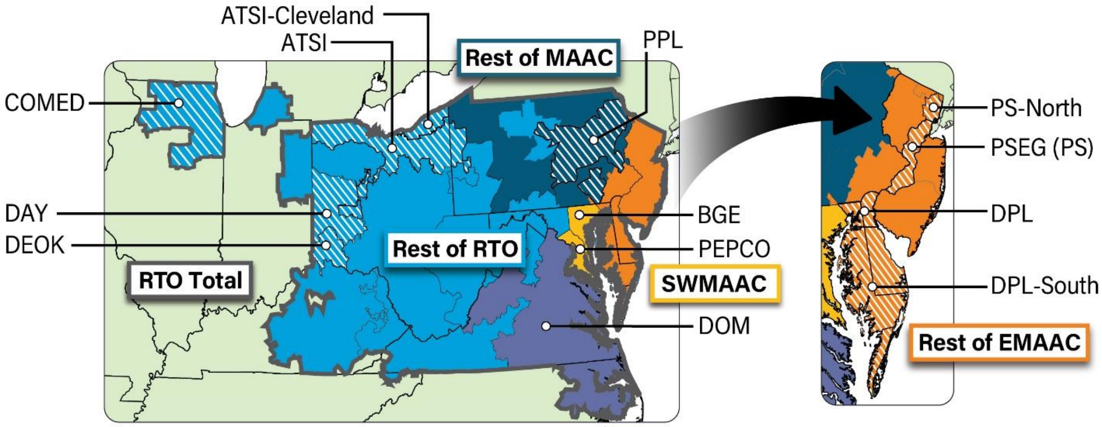
An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above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

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

Locational Deliverability Area Definition

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

Map 1. PJM LDAs



Executive Summary

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

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

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

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

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

Note: Clearing prices in bold indicate constrained LDA

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

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

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

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

Detailed Report

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

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

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

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

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

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

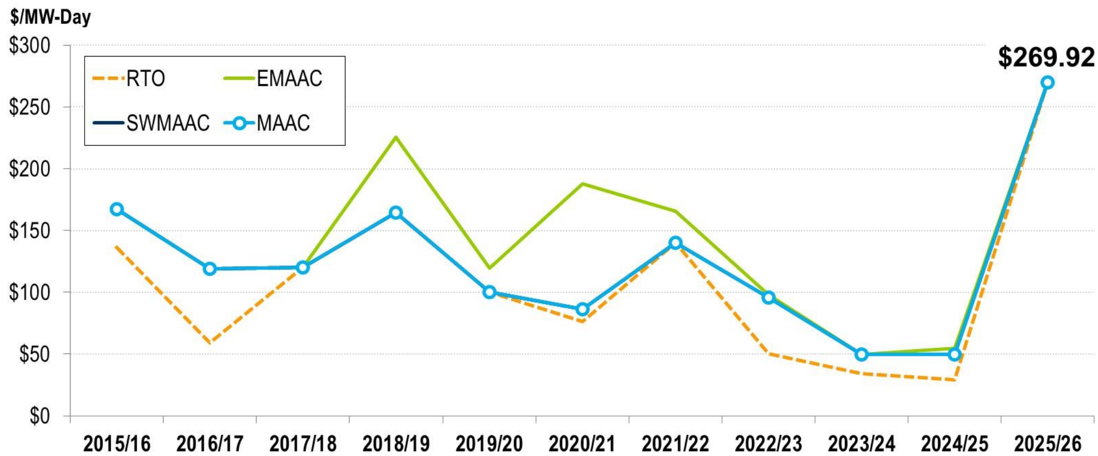


Table 3 provides the total offered and cleared MWs and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA. Since BGE and DOM were constrained LDAs, they cleared at a higher price than the rest of RTO or $466.35 and $444.26, respectively.

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

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

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

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

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

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

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

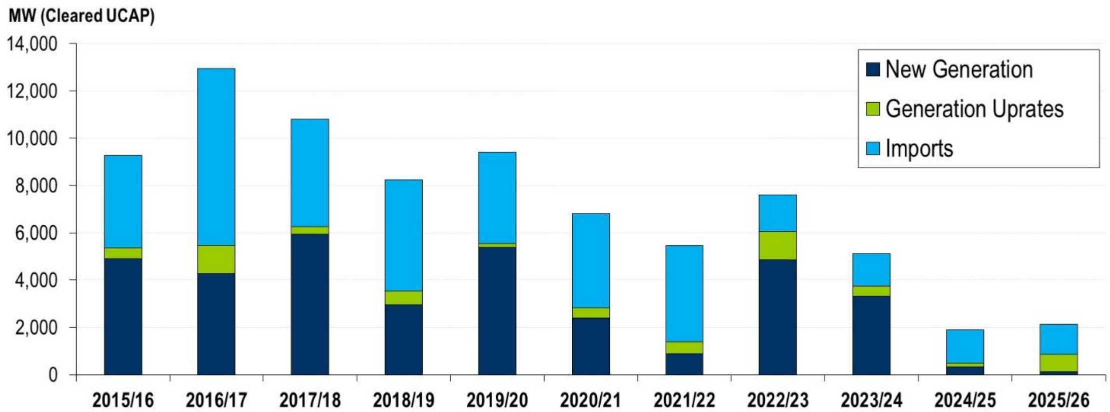


Table 4 contains a summary of the RTO resources for each cleared BRA from 2015/2016 through the 2025/2026 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

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

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

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

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

`

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

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

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

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

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

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

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

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

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

Offered and Cleared UCAP

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

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

Capacity Import Participation

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

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

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

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

Resource Type Participation

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

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

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

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

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

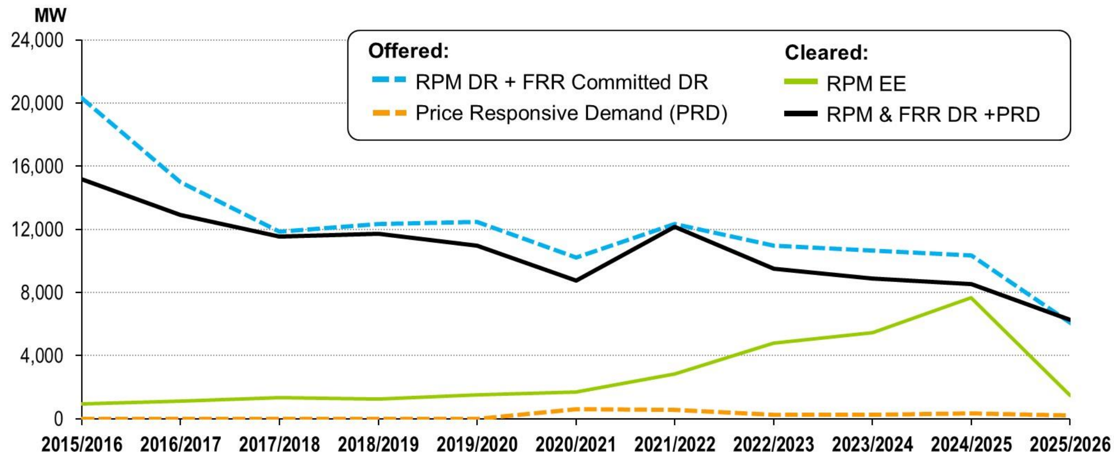


Table 9 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (1,424.5 MW), followed by AEP (1,055.7 MW) and then DOM (827.7 MW).

Table 9. DR and EE Offered and Cleared by LDA

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

** MW values include both Annual and Summer-Period Capacity Performance DR and EE*

*** MAAC sub-total includes all MAAC Zones*

Price Responsive Demand Participation

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

Table 10. PRD UCAP Committed

PRD UCAP Committed (MW)

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

UNIT POWER AGREEMENT

THIS AGREEMENT dated as of March 31, 1982 by and between INDIANA & MICHIGAN ELECTRIC COMPANY ("IMECO") and AEP GENERATING COMPANY ("AEGCO"),

WITNESSETH:

WHEREAS, IMECO, a subsidiary company of American Electric Power Company, Inc. ("AEP") under the Public Utility Holding Company Act of 1935 (the "1935 Act"), is presently constructing the Rockport Steam Electric Generating Plant at a site along the Ohio River near the Town of Rockport, Indiana, which will consist of two 1,300,000-kilowatt fossil-fired steam electric generating units and associated equipment and facilities (the "Rockport Plant"), the first unit ("Unit No. 1") of which is presently expected to be placed in commercial operation in 1984 and the second unit ("Unit No. 2") of which is presently expected to be placed in commercial operation in 1986; and

WHEREAS, AEGCO proposes to enter into an Owners' Agreement, dated as of March 31, 1982 (the "Owners' Agreement"), with IMECO and Kentucky Power Company ("KEPCO"), another subsidiary company of AEP under the 1935 Act, pursuant to which AEGCO and KEPCO plan to acquire undivided ownership interests, as tenants in common without right of partition, in the Rockport Plant which, upon completion of the construction of Unit No. 1, is thereafter to be operated as a part of the interconnected, integrated electric system comprising the American Electric Power System (the "AEP System"); and

WHEREAS, AEGCO proposes, upon completion of the construction of Unit No. 1 and the completion thereafter of the construction of Unit No. 2, to make available to IMECO, pursuant to this agreement, all of the available power (and the energy associated therewith) to which AEGCO shall from time to time be entitled at the Rockport Plant; and

WHEREAS, IMECO proposes to complete the construction of, the Rockport Plant pursuant to the provisions of the Owners' Agreement, and, upon completion of such construction, to operate the Rockport Plant pursuant to an operating agreement to be entered into by IMECO, AEGCO and KEPCO in accordance with the Owners' Agreement;

NOW, THEREFORE, in consideration of the terms and of the agreements hereinafter set forth, the parties hereto agree with each other as follows:

1.1 IMECO and AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 and Section 2.2 of this agreement, use their respective best efforts to complete and to make effective the arrangements described and specified in Section 1.1 and in Section 1.2 of the Capital Funds Agreement, dated as of March 31, 1982, between AEP and AEGCO.

1.2 AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 of this agreement, make available, or cause to be made available, to IMECO all of the power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, including test power produced during the course of the construction of generating units installed as a part of the Rockport Plant.

1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments are to commence under this Section 1.3 to be fair, and authorized, by the Federal Energy Regulatory Commission ("FERC", such term also including any successor Federal regulatory agency) as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Public Service Commission of Indiana as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

2.1 The performance of the obligations of AEGCO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit AEGCO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by IMECO of the construction of the Rockport Plant, the operation of the Rockport Plant, and for AEGCO to make available to IMECO all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant. AEGCO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

2.2 The performance of the obligations of IMECO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities necessary at the time to permit IMECO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities necessary at the time to permit IMECO to pay to AEGCO in consideration for the right to receive all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant the charges provided for in Section 1.3 of this agreement. IMECO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities. IMECO shall, to the extent permitted by law, be obligated to perform its duties and obligations hereunder, subject to then applicable provisions of this Section 2.2, (a) whether or not AEGCO shall have received all authorizations of governmental regulatory authorities necessary to permit AEGCO to perform its duties and obligations hereunder, (b) whether or not such authorizations, or any such authorization, shall at any time in question be in effect, and (c) so long as AEGCO and IMECO shall continue to be subsidiary companies of AEP (as said term is defined in Section 2(a)(8) of the 1935 Act) or a successor thereto, whether or not, at any time in question, IMECO shall have performed its duties and obligations under this agreement. In the event that either AEGCO or IMECO shall cease to be such a subsidiary company, then and thereafter IMECO shall not be relieved of its obligation to make payments pursuant to Section 1.3 of this agreement by reason of the failure of AEGCO to perform its duties and obligations hereunder occasioned by Act of God, fire, flood, explosion, strike, civil or military authority, insurrection, riot, act of the elements, failure of equipment, or for any other cause beyond the control of AEGCO; provided that, in any such event, AEGCO shall use its best efforts to put itself in a position where it can perform its duties and obligations hereunder as soon as is reasonably practicable.

3. To the extent that it may legally do so, IMECO and AEGCO each hereby irrevocably waives any defense based on the adequacy of a remedy at law which may be asserted as a bar to the remedy of specific performance in any action brought against it for specific performance of this agreement by IMECO, by AEGCO, or by a trustee under any mortgage or other debt instrument which IMECO or AEGCO may, subject to requisite regulatory authority, enter into, or by any receiver or trustee appointed for IMECO or AEGCO under the bankruptcy or insolvency laws of any jurisdiction to which IMECO or AEGCO is or may be subject; provided, however, that nothing herein contained shall be deemed to constitute a representation or warranty by IMECO or AEGCO that the respective obligations of IMECO or AEGCO under this agreement are, as a matter of law, subject to the equitable remedy of specific performance.

4. IMECO shall not be entitled to set off against any payment required to be made by IMECO under this agreement (i) any amounts owed by AEGCO to IMECO or (ii) the amount of any claim by IMECO against AEGCO. The foregoing, however, shall not affect in any other way the rights and remedies of IMECO with respect to any such amounts owed to IMECO by AEGCO or any such claim by IMECO against AEGCO.

5. The invalidity and unenforceability of any provision of this agreement shall not affect the remaining provisions hereof.

6. This agreement shall become effective forthwith and shall continue until all of the Notes issued by AEGCO under the Revolving Credit Agreement, dated as of March 31, 1982, of AEGCO shall have been paid in full, together with all accrued interest thereon; provided, however, that in the event that AEGCO shall, prior to such payment, create a Mortgage and Deed of Trust secured by a lien on all, or certain of its fixed physical properties, and shall issue bonds thereunder, this agreement shall continue until said Mortgage and Deed of Trust shall have been satisfied and discharged or said Notes have been paid in full, whichever event shall be the later.

7. This agreement shall be binding upon the parties hereto and their successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this agreement, shall in any event relieve either IMECO or AEGCO of any of their respective obligations hereunder, or, in the case of IMECO, reduce to any extent its entitlement to receive all of the power (and the energy associated therewith) available to AEGCO from time to time at the Rockport Plant.

8. The agreements herein set forth have been made for the benefit of IMECO and AEGCO and their respective successors and assigns, and no other person shall acquire or have any right under or by virtue of this agreement.

9. IMECO and AEGCO may, subject to the provisions of this agreement, enter into a further agreement or agreements between IMECO and AEGCO setting forth detailed terms and provisions relating to the performance by IMECO and AEGCO of their respective obligations under this agreement. No agreement entered into under this Section 9 shall, however, alter to any substantive degree the obligations of either party to this agreement in any manner inconsistent with any of the foregoing sections of this agreement.

10. IMECO shall, at any time and from time to time, be entitled to assign all of its right, title and interest in and to all of the power (and the energy associated therewith) to which IMECO shall be entitled under this agreement, but IMECO shall not, by such assignment, be relieved of any of its obligations and duties under this agreement except through the payment to AEGCO, by or on behalf of IMECO, of the amount or amounts which IMECO shall be obligated to pay pursuant to the terms of this agreement.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be duly executed as of the day and year first above written.

INDIANA & MICHIGAN ELECTRIC COMPANY

By G. P. Maloney
Vice President

AEP GENERATING COMPANY

By G. P. Maloney
Vice President

Docket No.: ER89-470-000
Company: AEP
FERC El. Rate Sch. No.: /
Supp. No.: 6
Filing Date: 5-30-89
Effective Date: I 05
1.6

AMENDMENT NO. 1

TO UNIT POWER AGREEMENT

This Amendment No. 1 dated as of May 8, 1989 by and between Indiana Michigan Power Company ("I&M" or "IMECO", formerly known as Indiana & Michigan Electric Company) and AEP Generating Company ("AEGCO") to the Unit Power Agreement dated as of March 31, 1982 by and between I&M and AEGCO ("Unit Power Agreement"),

WITNESSETH:

WHEREAS, I&M and AEGCO have entered into the Unit Power Agreement whereby, subject to regulatory approvals and certain other conditions, AEGCO agreed to make available, or cause to be made available, to I&M all of the power (and the energy associated therewith) which is available to AEGCO at the Rockport Plant and I&M agreed to pay AEGCO certain amounts;

WHEREAS, AEGCO has entered into six Participation Agreements, dated as of March 15, 1989, whereby it has agreed, subject to regulatory approvals and certain other conditions, to sell its 50% undivided interest in Unit 2 of the Rockport Plant and pursuant to six separate leases (the "Leases"), to leaseback a 50% undivided interest in the unit; and

WHEREAS, Section 3.01 of the Participation Agreements specify that as a condition to closing AEGCO and I&M shall have entered into, and shall have filed with the Federal Energy Regulatory Commission ("FERC") for its approval, an amendment to the Unit Power Agreement which shall, among other things, (i) specifically confirm that basic rent payable under the Leases is an item of operating and other expenses of AEGCO referred to in Section 1.3 thereof, and (ii) specifically provide that the Unit Power Agreement shall continue in full force and effect until the lease term shall have expired or been terminated and all basic rent payable under the Leases shall have been paid in full;

NOW, THEREFORE, in consideration of the terms and agreements hereinafter set forth, the parties hereto agree as follows:

1. Section 1.3 of the Unit Power Agreement is hereby amended to read as follows:

> "1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities, and lease rental payments, including any amount of Basic Rent (as such term is defined in Section 3(a) of the forms of Lease attached as Exhibit A to the Participation Agreements) which AEGCO may be required to pay pursuant to the Leases, and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time, and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments

76

are to commence under this Section 1.3 to be fair, and authorized, by the FERC, including any successor Federal regulatory agency as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Indiana Utility Regulatory Commission as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant."

2. Section 6 of the Unit Power Agreement is hereby amended to read as follows:

"6. This agreement shall become effective forthwith and shall continue in full force and effect until the latter of the date that: (1) all of the Notes issued by AEGCO under the Revolving Credit Agreement, dated as of March 31, 1982, of AEGCO shall have been paid in full, together with all accrued interest thereon; or (ii) the last of the Lease Terms (as that term is defined in the Participation Agreements) shall have expired or been terminated and all Basic Rent payable under all of the Leases shall have been paid in full; provided, however, that in the event that AEGCO shall, prior to such payment, create a Mortgage and Deed of Trust secured by a lien on all, or certain of its fixed physical properties, and shall issue bonds thereunder, this agreement shall continue until said Mortgage and Deed of Trust shall have been satisfied and discharged."

3. This Amendment No. 1 shall become effective on the date on which the last of the following events shall have occurred: (i) this Amendment No. 1 shall have been filed with and accepted for filing without condition or change by the FERC under the Federal Power Act (FPA) as a rate schedule under circumstances where the FERC (a) shall have issued an order under the FPA that

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this Amendment No. 1 shall become effective in its entirety as such rate schedule under the FPA, as proposed by the parties in their filings with the FERC, and (b) shall not have, in such order or any separate order, instituted an investigation or proceeding under the provisions of the FPA with respect to the justness and reasonableness of the provisions of this Amendment No. 1; (ii) the order or orders of the FERC, referred to in (i) above, shall have become final and not subject to review under Section 313 of the FPA; or (iii) the Closings (as defined in the Participation Agreements).

IN WITNESS WHEREOF, the parties hereto have caused this Amendment No. 1 to be duly executed as of the date and year first above written.

INDIANA MICHIGAN POWER COMPANY

By: /s/ R. E. DISBROW
Vice President

AEP GENERATING COMPANY

By: /s/ G. P. MALONEY
Vice President

RATE DESIGN

The total revenue requirement of AEGCO calculated pursuant to the IMECO-AEGCO Unit Power Agreement designated AEGCO FERC Rate Schedule No. 1 is designed to recover for AEGCO its total cost of providing power (and the energy associated therewith) available to AEGCO at the Rockport Plant.

DETERMINATION OF POWER BILL

In accordance with Section 1.3 of the Unit Power Agreement, I&M agrees to pay AEGCO in consideration for the right to receive all power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M), such amounts, less any amounts recovered by AEGCO from other sources, as shall be determined monthly as described below. Such amounts shall be calculated separately for Unit No. 1 (including Common Facilities) and for Unit No. 2. I&M shall then commence the payment of such amounts (power bill) on the earlier of the following dates: (i) June 30, 1985 and (ii) the date on which power including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

The power bill for Unit No. 1 (including Common Facilities) shall be calculated each month and shall reflect recovery only of those costs related to the plant in service. It shall consist of the sum of (a) a return on common equity, (b) a return on other capital, (c) recovery of operating expenses and (d) provision for federal income taxes as described below and as illustrated in the example attached.

(a) Return on Common Equity, which shall be equal to the product of (i) the amount of common equity outstanding at the end of the previous month, but not more than 40% of the capitalization of AEGCO at the end of the previous month; (ii) 1.0133 (12.16% annual rate) as described in Note 1 below; (iii) the Operating Ratio, as defined in Note 2 below; and (iv) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below, plus the product of (v) the amount of common equity in excess of 40% of the capitalization of AEGCO at the end of the previous month, if any such excess shall be determined; (vi) the weighted cost of debt outstanding at the end of the previous month; (vii) the Operating Ratio, as defined in Note 2 below; and (viii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, the amount of common equity shall be equal to the sum of the Common Stock (Accounts 201-203, 209, 210, 212, 214 and 217), Other Paid-In Capital (Accounts 207, 208, 211 and 213), and Retained Earnings (Accounts 215-216) outstanding at the end of the previous month. Total capitalization shall be equal to the sum of Long-term Debt (Accounts 221-226 including current maturities and unamortized debt premium and discounts), Short-Term Debt (Accounts 231 and 233), Preferred Stock (Accounts 204-206), and Common Equity less any Temporary Cash Investments, Special

Deposits and Working Funds (Accounts 132-134, 136, and 145) outstanding at the end of the previous month.

(b) Return on Other Capital, which shall be equal to the product of (i) the amount equal to the net interest expense associated with Long-Term and Short-Term Debt, net of any Temporary Cash Investments, Special Deposits and Working Funds, plus the preferred stock dividend requirement associated with the Preferred Stock outstanding at the end of the previous month; (ii) the Operating Ratio, as defined in Note 2 below; and (iii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, net interest expense shall be equal to the sum of (i) the amount of Long-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Long-Term Debt and (ii) the amount of Short-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Short-Term Debt, less (iii) the amount of Temporary Cash Investments, Special Deposits and Working Funds outstanding at the end of the previous month multiplied by the weighted cost of Long Term and Short-Term Debt combined determined pursuant to (i) and (ii) above.

(c) Recovery of Operating Expenses, excluding federal income taxes, which shall consist of provision for depreciation and amortization (Accounts 403-407, 411), including Asset Retirement Obligation (ARO) depreciation and accretion expenses (Accounts 403.1 and 411.10), taxes other than federal income taxes (Accounts 408-411) and operating and maintenance expenses associated with Unit No. 1 (including Common Facilities) offset by other operating revenues as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities (See Note 6). Recovery of expenses for test energy shall be limited to recovery of actual fuel expense as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities. Operating and maintenance expenses shall include, and reflect the recovery of, Steam Power Generation Expenses (Accounts 500-515 including lease rental payments recorded in Account 507), Other Power Supply Expenses (Accounts 555-557), Transmission Expenses (Accounts 560-574), Distribution Expenses (Accounts 580-598), Customer Accounts Expenses (Accounts 901-905), Customer Service and Informational Expenses (Accounts 906-910), Sales Expenses (Accounts 911-917) and Administrative and General Expenses (Accounts 920-933 and 935). Recovery of 501 fuel expenses shall be adjusted to reflect the deferral and/or feedback of unrecovered levelized fuel expenses as may be recorded on the Company's books or as is currently recorded on the books of I&M.

(d) Provision for Unit No. 1's (including Common Facilities) allocated share of net current and deferred federal income tax expense and investment tax credit included in operating income as determined by the Company in accordance with federal income tax law, SEC approved consolidated current tax allocation procedures, and FERC rules and regulations.

For purposes of computing federal income taxes, the interest expense deduction shall be equal to the sum of the net interest expense computed in accordance with paragraph (b) above plus the imputed interest expense associated with common equity that is in excess of 40% of AEGCO's net capitalization.

The power bill for Unit No. 2 shall be calculated in the same manner as described for Unit No. 1 above except that it shall reflect the Unit No. 2 Net In-Service Investment Ratio and those expenses associated with Unit No. 2.

Notes:

1. **Return on Equity**

The return on common equity allowance shall be based upon a rate of return of 12.16% as set forth in sub-paragraph (a) above.

In October of 1988, and every October thereafter for the effective duration of AEGCO's formula rate, any purchaser under AEGCO's two unit power agreements, any state regulatory commission having jurisdiction over the retail rates of purchasers under these agreements, or any other entity representing customers' interest, may file a complaint with the Commission with respect to the specified rate of return on common equity. If the Commission, in response to such a complaint, or on its own motion, institutes an investigation into the reasonableness of the specified return on common equity, such investigation shall be pursued under the special procedures set forth as follows:

A. The only issue to be addressed under these special procedures shall be the continued collection of the return on equity as incorporated in the formula rate; and

B. Refund will be due, should the return on equity, specified in the formula be found not just and reasonable, dating from the first day of January immediately following the date the complaint is filed or an investigation is instituted by the Commission on its own motion, calculated on the resulting difference in rates due to the application of the return found to be just and reasonable and the return stated in the formula. The first such effective date for the calculation of refunds shall be January 1, 1989.

Any other complaint which challenges the justness and reasonableness of any other component of the filed formula rate or any other complaint filed at any other time which challenges the justness and reasonableness of the specified rate of return on common equity and which is set for investigation by the Commission shall be pursued under Section 206 of the Federal Power Act.

2. **Operating Ratio**

The Operating Ratio shall be computed each month commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform

System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived by dividing (a) the amount of Electric Plant In Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations); less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111 but excluding amounts associated with Asset Retirement Obligations); plus Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below); Materials and Supplies (Accounts 151-156 and 163 as adjusted pursuant to the provisions of Note 4.C. below); Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below); Prepayments (Account 165); Deferred Ash pond cost (Account 182.3); other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 less Accounts 232-234, 236, 237, 238, 241 and 242); and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No. 2); less Asset Retirement Obligation (Account 230); less Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the plant in service by (b) the sum of (i) the amount determined pursuant to (a) plus (ii) the amount of Construction Work In Progress (Account 707) plus Materials and Supplies (Accounts 151-156 and 163), less Accumulated Deferred Federal Income Taxes related to the construction work in progress plus (iii) Plant Held for Future Use (Account 105), Other Deferred Debits (Account 186) and the amount of fuel inventory over the allowed level (Account 151.10) not otherwise included in (a) above.

3. Net In-Service Investment Ratio

The Unit No. 1 Net In-Service Investment Ratio shall be equal to 1.0 during the period commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation and shall remain at 1.0 up to, but not including, the month in which Unit No. 2 at the Plant is placed in commercial operation. Thereafter, the Net In-Service Investment Ratio shall be computed each month, based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived as follows:

A. Unit No. 1 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 1 and Common Facilities by (b) the sum of the Net In-Service Investment associated with Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

B. Unit No. 2 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 2 by (b) the sum of the Net In-Service Investment associated with the Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

4. Net In-Service Investment

The Net In-Service Investment shall be computed each month commencing with the month in which Unit No. 2 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall consist of the following:

A. Unit No. 1 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), and Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 less Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253), less Asset Retirement Obligation (Account 230), less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to such Unit No. 1 and Common Facilities in-service investment.

B. Unit No. 2 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 less Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No.2), less Asset Retirement Obligation (Account 230), less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the Unit No. 2 in-service investment.

C. AEGCO shall be permitted to earn a return on its fuel inventory, recorded in Account 151.10, not in excess of a 68-day coal supply as defined herein. To the extent AEGCO's actual fuel inventory exceeds the allowable 68-day level, the return on such excess shall be recorded in a memo account. When AEGCO's actual fuel inventory is less than the allowable 68-day level, AEGCO shall be permitted to recover the return previously unrecovered, but in no event shall the power bill reflect a return on fuel inventory in excess of 68-day supply.

A 68-day coal inventory level shall be determined for each unit annually, and shall be based upon the actual experienced daily burn during the preceding calendar year. The actual experienced daily burn shall be defined to exclude the effect of forced and scheduled outages as well as curtailments as follows:

For each unit:

$$\text{Actual experienced daily burn} = 24 \text{ hours} \quad \left(\frac{\text{Tons burned per year}}{\text{Operating hours}}\right)$$

Where:

Operating hours = Hours in year minus forced and scheduled outage hours minus curtailment equivalent outage hours

and

Curtailment equivalent outage hours = The product for each curtailment of:

$$\frac{\text{kW of curtailed capacity}}{\text{kW of rated capacity}} \quad x \quad \text{Curtailment hours}$$

The value of the allowable 68-day coal supply used to determine each month's power bill shall be equal to the number of tons determined above multiplied by the cost per ton of coal in inventory at the end of the previous month.

For 1990, a 68-day coal supply for AEGCO's share of Rockport Unit No. 2 shall be based on 12 months ending December 1990 data. For 1990 billing purposes, however, a 68-day coal supply for AEGCO's share of Rockport Unit No.2 shall initially be assumed to be equal to the 68-day coal supply for AEGCO's share of Rockport Unit No. 1, adjusted to reflect the Btu content and the unit cost of the coal for Rockport Unit No. 2.

AEGCO shall maintain a cumulative record of the unrecovered return as well as the subsequent recovery of that return as follows:

i) To the extent that AEGCO's actual fuel inventory exceeds the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the sum of the unrecovered return on fuel inventory and the return on previously unrecovered amounts. The unrecovered return on fuel inventory shall be calculated each month by deriving the difference between the power bill that would result if full recovery were provided and the power bill that results with the 68-day limitation imposed. The return on previously unrecovered amounts shall be calculated by multiplying the cumulative return unrecovered at the end of the previous month by the capital costs used to derive the power bill, adjusted for federal income taxes.

ii) To the extent that AEGCO's fuel inventory is less than the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the return on previously unrecovered amounts less the recovered return in excess of actual inventory levels. The return on previously unrecovered amounts shall be calculated as described in (i) above. The recovered return in excess of actual inventory levels shall be calculated by deriving the difference between the power bill that would result if actual inventory balances were used and the power bill that results with an imputed inventory level. In no event will the cumulative value of the unrecovered return be allowed to fall below zero.

D. AEGCO shall be permitted to include as part of its Net In-Service Investment Numerator amounts subsequently recorded in Accounts 105 and 186 subject to the conditions set forth in the Offer of Settlement in FERC Docket No. ER84-579-000, et al.

E. Other Special Funds (Account 128), Other Current and Accrued Assets (Accounts 131, 135, 143, 146, 171 and 174), Other Deferred Debits (Account 181), Other Current and Accrued Liabilities (Accounts 232-234, 236, 237, 238, 241 and 242), and Other Deferred Credits (Account 253) shall be directly assigned to unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such balances shall be allocated between the units in proportion to the net dependable capability of each of the units.

F. To recognize that the lease rental expense will be collected monthly but that the lease payment will be paid semiannually, the lease rental payable balance will be reflected as a rate base reduction in calculating the operating ratio and the Unit 2 net-in-service investment ratio as a means to credit the Unit 2 customers for the time value of money.

5. Investment Balances

For the purpose of calculating the Operating Ratio and Net In-Service Investment Ratio, amounts shall reflect the balances, as recorded on the Company's book in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month, except that when plant greater than or equal to 1% of the prior month ending plant value is transferred into service during the current month, such prior month balances shall be adjusted to reflect such transfers to service. Such adjustment shall be pro-rated for the number of days during the month that such plant addition was in-service.

6. Allocation of Expenses

Operating expenses shall be directly assigned to Unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such expenses shall be allocated between the units in accordance with the basis that gave rise to such expense.

AEGCO's operating and maintenance expenses shall include, and AEGCO shall be allowed recovery of, administrative and general expenses, related payroll taxes and other cost, allocated to AEGCO by I&M as operator of the Rockport Plant or incurred directly by AEGCO.

I&M shall allocate to AEGCO, a portion of I&M's administrative and general expenses charged to Accounts 920, 921, 922, 923, 924, 925, 926, 931 and 935; related payroll taxes charge to Account 408; and a portion of the expenses of the Rockport Information Center charged to Accounts 506, 511 and 514 that generally relate to Rockport Plant operations. Such charges shall be allocated to AEGCO on the basis of the ratio of AEGCO's share of the Rockport Plant operation and maintenance wages and salaries, divided by the sum of total Rockport Plant operations and maintenance wages and salaries, plus all other I&M operation and maintenance wages and salaries, less I&M's administrative and general wages and salaries. For the period beginning December 10, 1984 and ending December 31, 1985 this ratio will be developed based on actual 1985 amounts. In subsequent calendar years, this ratio will be adjusted annually based on the prior calendar year's amounts.

AEGCO's operation and maintenance expenses shall also include, and AEGCO shall be allowed recovery of, other administrative and general expenses directly incurred by AEGCO and included in the appropriate administrative and general expense accounts.

BILLINGS AND PAYMENTS

All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the

Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon, the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of the unit power agreements.

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 2
CASE NO. U-20530 (2020 PSCR RECONCILIATION)

DATA REQUEST NO. 2-29-AG

Request

Refer to AG 1-11 attachment 1:

a. Has the Michigan Public Service Commission ever approved this agreement? If yes, identify the case number and order date.

b. Referring to section 1.3 of the agreement, how was the return on equity calculated?

c. Referring to section 1.3 of the agreement, provide the amounts received by AEG from any other sources in 2020, and explain how those amounts were used to calculate the amount I&M owed.

d. Identify all actions I&M has taken since the Commission's June 7, 2019 Order in Case No. U-18404 to seek or pursue amendments, new contractual arrangements, or other negotiations regarding any aspect of this agreement, including but not limited to the return on equity.

e. Produce all documents and communications related to your response to the preceding sub-part.

Response

a. The Commission originally approved the inclusion of the capacity charges related to the purchase of Rockport Plant Unit 2 capacity from AEP Generating Company (AEG) in its order in Case No. U-9656, dated Feb. 12, 1991. Furthermore, the costs of the Unit Power Agreement with AEG have been included in all subsequent base rate cases and power supply cost recovery cases since that date.

b. The calculation for the return on equity component of the bill is based on the method identified in AEP Generating Company Rate Schedule No. 1, on file with the FERC.

c. I&M objects to this request on the basis that it seeks information that is outside the scope of the PSCR and, therefore, is not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, the Company states that any amounts received by AEG other than those costs included in the Company's 2020 PSCR Reconciliation filing are not relevant in determining the reasonableness of the costs included in this reconciliation proceeding.

d. Please see FERC Docket no. ER19-717-000 for the most recent rate update filing made on behalf of AEP Generating Company to update their formula rate calculation.

e. The docket and all pertinent documents can be found at FERC.gov.

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD AND SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-21262

DATA REQUEST NO. 1-10-SCCUB

Request

Provide the ICAP for AEG in 2023.

Response

I&M objects to this request on the grounds it is vague, ambiguous and confusing and cannot be answered in its current form because it is not clear what “ICAP for AEG” means.

Subject to and without waiving objections, the Company interprets the question as seeking the Installed Capacity (ICAP) value for the Company's share of Rockport Unit 1 obtained through its Unit Power Agreement with AEP Generating Co. (AEG). Furthermore, ICAP values are established by PJM Planning Year which runs from June 1 to May 31. The Company's ICAP value for Rockport Unit 1 was 1,317.5 MW for both the 2022-2023 and 2023-2024 PJM Planning Years. The portion obtained through the Unit Power Agreement is 50% of that value or 658.8 MW.

Preparer

Stegall

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD AND SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-21262

DATA REQUEST NO. 1-41-SCCUB

Request

Provide the AEG energy and ancillary market revenues for each month between 2018 – 2023.

Response

Please see SCCUB 1-41 Attachment 1 for the requested information.

Preparer

Stegall

Indiana Michigan Power Company

Energy Revenues and Ancillary Revenues from the I&M Share of the Rockport Plant

	2018		2019		2020		2021		2022		2023	
	Energy	**Ancillary**	**Energy**	**Ancillary**	**Energy**	**Ancillary**	**Energy**	**Ancillary**	**Energy**	**Ancillary**	**Energy**	**Ancillary**
Jan	$58,779,701	$1,766,601	$27,445,386	$151,181	$1,489,749	$4,026	$290,051	$21	$32,919,664	$592,283	$2,321,281	$1,139
Feb	$15,431,813	$40,735	$17,908,071	$79,677	$3,742,093	$44,928	$37,490,120	$47,922	$20,397,666	$257,744	$2,920,402	$5,294
Mar	$30,319,619	$115,436	$16,738,149	$150,367	$4,654,122	$47,116	$3,321,779	$6,437	$329,223	$0	$0	$0
Apr	$25,907,778	$207,364	$22,903,674	$274,640	$6,137,046	$108,205	$5,104,513	$51,319	$32,630,479	$415,028	$0	$0
May	$26,310,347	$185,341	$16,367,484	$292,053	$4,577,173	$37,991	$11,708,899	$109,686	$33,674,965	$100,576	$0	$0
Jun	$31,225,582	$168,397	$6,331,374	$53,429	$11,431,657	$133,588	$25,561,750	$282,727	$46,170,054	$118,588	$4,730,102	$30,438
Jul	$25,325,080	$285,788	$30,730,544	$276,658	$10,193,487	$97,203	$25,621,067	$55,964	$69,155,346	$717,124	$3,372,511	$51,006
Aug	$30,192,459	$190,963	$13,862,759	$129,037	$12,975,291	$142,297	$29,163,852	$145,849	$51,806,583	$211,603	$6,569,057	$70,503
Sep	$24,575,880	$230,736	$15,338,879	$201,082	$8,743,478	$70,259	$2,207,530	$14,091	$2,915,133	$590	$1,437,467	$22,648
Oct	$26,549,717	$180,560	$7,136,893	$151,395	$1,084,436	$1,423	$0	$0	$0	$0	$38,692	$0
Nov	$21,730,884	$55,357	$15,711,335	$159,852	$7,139,167	$42,382	$0	$0	$10,648,515	$23,675	$1,270,047	$23,258
Dec	$18,896,192	$50,683	$1,070,908	$32,450	$0	$0	$16,063,320	$178,680	$68,686,088	$551,737	$0	$0

INDIANA MICHIGAN POWER COMPANY
CITIZENS UTILITY BOARD AND SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-21262

DATA REQUEST NO. 1-44-SCCUB

Request

Has I&M or AEPSC undertaken any effort to benchmark the costs of the UPA to any other comparators? If yes, produce same.

Response

Yes. Please see Section V of the direct testimony of Company witness Stegall and Exhibit IM-5.

Preparer

Stegall

Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price without having to build capacity or purchase capacity bilaterally at monopoly prices. The first, daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. But in order for the PJM markets to be self sustaining, the net revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market.

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources, with the current exception of intermittent and storage capacity, are required to offer into the capacity auctions. All LSEs must buy capacity equal to their peak load plus a reserve margin.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the 2024/2025 Base Residual Auction.[2] The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 See the "Analysis of the 2024/2025 RPM Base Residual Auction," (October 30, 2023) <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf>.

Table 5-1 The capacity market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[3] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[4]
- Participant behavior was evaluated as competitive in the 2024/2025 BRA after the Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021.[5] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.
- Market performance was evaluated as competitive based on the 2024/2025 Base Residual Auction after the Commission order eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.
- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction was delayed and held in June 2022, the 2024/2025 Base Residual Auction was delayed and held in December 2022, and first and second incremental auctions for the 2022/2023 through 2028/2029 Delivery Years are canceled if within 10 months of the revised BRA schedule.[6]

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[7] Currently, intermittent and storage resources are exempt from the must offer requirement, although that is not a viable long term design element for the capacity market. The fundamental goal of the must offer requirement, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply. If some resources hold CIRs (capacity interconnection rights) that provide access to the transmission system required for the deliverability of

3 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.

4 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

5 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023). The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

6 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021), 183 FERC ¶ 61,172 (2023).

7 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

energy, but do not offer, those resources are exercising market power by blocking access to the transmission system that could be used by a resource willing to offer into the capacity market.

Under RPM, capacity obligations are annual.[8] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[9] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[10] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[11]

The 2023/2024 RPM Third Incremental Auction was conducted in 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.[12] [13] The 2025/2026 RPM Base Residual Auction was scheduled for June 2023 but postponed until June 2024.[14]

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[15] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option, and, as a result of Capacity Performance rule changes, except for intermittent and capacity storage resources including hydro. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. The experience with Winter Storm Elliott (Elliott) has made clear that the extremely high penalties created in the CP model are not an effective incentive. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In 2023, RPM installed capacity decreased 5,135.9 MW or 2.8 percent, from 183,388.8 MW on January 1, to 178,252.9 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2024/2025 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2023, 49.3 percent was gas; 21.8 percent was coal; 18.1 percent was nuclear; 4.2 percent was hydroelectric; 2.5 percent was oil; 1.9 percent was wind; 0.4 percent was solid waste; and 2.0 percent was solar.
- **Market Concentration.** In the 2024/2025 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[16] In the 2023/2024 RPM Third Incremental Auctions, 36 participants out of 51 participants in the total PJM market passed the TPS test, eight participants out of 17

8 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
9 See 126 FERC ¶ 61,275 at P 86 (2009).
10 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
11 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
12 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.
13 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
14 See 183 FERC ¶ 61,172 (2023).
15 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
16 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

participants in the MAAC LDA market passed the TPS test, and all participants in the EMAAC and BGE LDA markets failed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[17] [18] [19]

- **Imports and Exports.** Of the 1,527.1 MW of imports in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.
- **Demand Resources.** Committed DR was 7,707.9 MW for June 1, 2023, as a result of cleared capacity for demand resources in RPM auctions for the 2023/2024 Delivery Year (8,174.1 MW) less replacement capacity (466.2 MW).
- **Energy Efficiency Resources.** Committed EE was 5,891.1 MW for June 1, 2023, as a result of cleared MW in RPM auctions for the 2023/2024 Delivery Year (5,896.4 MW) less replacement MW (5.3 MW).

Market Conduct

- **2024/2025 RPM Base Residual Auction.** Of the 964 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 22 generation resources (2.3 percent).
- **2023/2024 RPM Third Incremental Auction.** Of the 250 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (2.0 percent).

Market Performance

- The 2023/2024 RPM Third Incremental Auction was conducted in 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement. The weighted average capacity price for the 2023/2024 Delivery Year is $42.01 per MW-day, including all RPM auctions for the 2023/2024 Delivery Year. The weighted average capacity price for the 2024/2025 Delivery Year is $40.73 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year held through 2023.
- For the 2023/2024 Delivery Year, RPM annual charges to load are $2.2 billion.
- In the 2024/2025 RPM Base Residual Auction, the market performance was determined to be competitive.

Part V Reliability Service (RMR)

- Of the eight companies (24 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other six companies (17 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in 2023 was 5.5 percent, a decrease from 7.9 percent in 2022.[20]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2023 was 83.2 percent, an increase from 82.0 percent in 2022.

Recommendations[21]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported Q3, 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply

17 See OATT Attachment DD § 6.5.
18 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
19 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
20 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on January 24, 2024. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.
21 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, energy efficiency, and imports.[22] [23] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 delivery year, and the tariff rationale for inclusion no longer exists.[24] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources at or below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined ELCC derating factors are lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Adopted 2023.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away, only to intermittent resources, winter CIRs that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[25]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported Q3 2023. Status: Partially adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up

22 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
23 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
24 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 36 (Nov. 15, 2023).
25 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[26]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[27]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends use of the MMU's Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[28] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis

26 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

27 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

28 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

of modeling assumptions.[29] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity whether a new resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)[30]
- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[31]

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance,

29 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

30 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

31 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported Q2 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported Q3 2023. Status: Not adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported Q3 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported Q3 2023. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2024/2025 BRA compared to a vertical demand curve was a significant increase in customer payments for load as a result of buying more capacity than needed for reliability and paying a price above the competitive level as a result. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

For the 2024/2025 RPM Base Residual Auction, the level of committed demand resources (8,083.9 MW UCAP) almost equals the entire level of excess capacity (8,086.8 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called and can set prices at shortage levels simply by being called, when demand side resources are a significant share of required reserves. Rule changes implemented following Winter Storm Elliott eliminated the automatic triggering of a PAI when demand resources are called.[32]

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[33] [34] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market

32 Letter Order, FERC Docket No. ER23-1996-001 (October 2, 2023).
33 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
34 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).

performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, but the modified market power rules were not implemented in the 2022/2023 BRA.[35] [36] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results in the 2022/2023 BRA.

The implementation of the market power mitigation rules effective September 2, 2021, that corrected the definition of the market seller offer cap in the 2023/2024 BRA resolved the market power issues from the prior two BRAs. The results of the 2023/2024 BRA and the 2024/2025 BRA were competitive.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the CP market seller offer cap was based on strong assumptions that are not correct. The derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The logic underlying the CP market seller offer cap was circular. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[37] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[38] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[39] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[40] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[41] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM

35 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47 (February 21, 2019) ("IMM MSOC Complaint").
36 176 FERC ¶ 61,137 (2021); 178 FERC ¶ 61,121 (2022); *appeal denied*, Vistra Corp., et al. v. FERC, Case No. 21-1214 (D.C. Cir. October 10, 2023).

37 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.
38 See page 55 of CP Filing.
39 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.
40 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).
41 See page 43 of CP Filing.

for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

The MMU supported the modified CP filing and prepared the mathematical appendix.[42] However, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[43] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[44] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[45] [46]

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI. CP has not worked as the theory suggested. PAI events are high impact low probability events. The failure of the PAI incentives to prevent a very high level of outages illustrates the weakness of incentives based on this type of event. The actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is B * (1 – EFORd) for a unit, where B is the balancing ratio and EFORd is the forced outage rate. For example, if B were 80 percent, the actual required performance for a unit with a 10 percent EFORd would be only 72 percent of ICAP (.80 * .90). For units with high historical forced outage rates, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unsupported assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small

42 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).

43 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).

44 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

45 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").

46 176 FERC ¶ 61,137 (2021), *order on reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).

number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created a new risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in unsupported concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

Winter Storm Elliott provided the first real test of the CP design. Winter Storm Elliott showed that the CP design does not provide effective incentives. There was an extremely high forced outage level during Winter Storm Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year that included Elliott. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions, imposing penalties and paying bonuses is complex and very difficult to administer, and includes substantial subjective elements. PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Winter Storm Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[47] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply. The purpose of the must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights). If a resource has CIRs that provide access to the transmission system required for the deliverability of energy, but do not offer, those resources are exercising market power by blocking access to the transmission system that could be used by a resource willing to offer into the capacity market. For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The MMU recommends that resources return CIRs to the market on the day of retirement. The same logic should be applied to intermittent and storage resources. The failure to apply the must offer requirement will create increasingly significant market design issues, issues of open access to the transmission system, and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases. The failure to apply the must offer requirement consistently could also result in very significant changes in supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

It is not clear why intermittents and storage were exempted from the must offer obligation to date, and no explicit reason stated, but as the role of intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The capacity market has

47 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

included balanced must buy and must sell obligations from its inception.

The MMU concludes that the results of the 2024/2025 RPM Base Residual Auction were competitive. A competitive offer in the capacity market is equal to net ACR.[48] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2024/2025 Base Residual Auction, the rules permit the exercise of market power without mitigation for seasonal products through uplift payments for noncompetitive offers, rather than through higher prices.[49] Although the impact did not arise in the 2024/2025 Base Residual Auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[50] [51] [52] [53] [54] [55] [56] [57] [58] [59] [60] In 2023, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 5,979.8 ICAP MW (5,693.8 MW UCAP) on June 1,

48 174 FERC ¶ 61,212 ("March 18th Order") at 65.
49 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

50 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
51 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
52 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
53 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
54 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).
55 See "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
56 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
57 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
58 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
59 See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
60 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).

2023, and will have excess reserves of 5,020.8 ICAP MW (4,761.4 MW UCAP) on June 1, 2024, based on current positions.[61] A majority of capacity investments in PJM were financed by market sources.[62] Of the 51,857.2 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 39,471.5 MW (76.1 percent) were based on market funding. Of the 3,824.1 MW of additional capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years, 3,284.6 MW (85.9 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

61 The calculated reserve margin for June 1, 2024, does not account for cleared buy bids that have not been used in replacement capacity transactions.

62 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Table 5-2 RPM related MMU reports: 2023

Date	Name
January 13, 2023	IMM Comments re ELCC/CIR Complaint Docket No. EL23-13 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_No_EL23-13_20230113.pdf
January 13, 2023	Analysis of the 2022/2023 RPM Base Residual Auction - Revised http://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf
January 13, 2023	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2025-2026_Base_Residual_Auction_20230113.pdf
January 18, 2023	IMM Comments re Modernizing Electricity Market Design Docket No. AD21-10 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_No_AD21-10_20230118.pdf
January 18, 2023	MMU Calculated Net Revenue Values for the 2025/2026 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Calculated_Net_Revenue_Values_20230118.pdf
January 20, 2023	IMM Comments re LDA Reliability Requirement Docket No. ER23-729 and EL23-19 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_Nos_ER23-729_EL23-19_20230120.pdf
January 31, 2023	IMM Capacity Market Design Proposal http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF_Capacity_Market_Design_Proposal_20230131.pdf
February 3, 2023	IMM Answer re LDA Reliability Requirement Docket No. EL23-19 and ER23-729 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_Docket_No_EL23-19_ER23%E2%80%90729_20230203.pdf
February 10, 2023	High Level Capacity Market Design Proposal http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_High_Level_Capacity_Market_Design_Proposal_20230210.pdf
February 16, 2023	IMM Answer re LDA Reliability Requirement Docket No. EL23-19 and ER23-729 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_Docket_No_EL23-19_ER23-729_20230216.pdf
March 15, 2023	IMM Comments - Corrected re Maintenance Adder Costs Revisions Docket No. ER23-1138 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Corrected_Docket_No_ER23-1138_20230315.pdf
March 16, 2023	IMM Answer to Protests re Generation Capacity Resources CIRs in ELCC Docket No. ER23-1067 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_to_Protest_Docket_No_ER23-1067_20230316.pdf
March 16, 2023	IMM Determinations Posted for the PJM 2025/2026 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2025-2026_Base_Residual_Auction_20230316.pdf
March 20, 2023	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 and 2024/2025 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20230320.pdf
April 20, 2023	Capacity Market Design Proposal http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_CIFP_Capacity_Market_Design_Proposal_20230420.pdf
May 2, 2023	IMM Comments re PJM BRA Delay Docket No. ER23-1609 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_No_ER23-1609_20230502.pdf
June 14, 2023	Capacity Market Design Proposal: Sustainable Capacity Market (SCM) http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF_CIFP_Capacity_Market_Design_Proposal_20230613.pdf
June 15, 2023	Speaker Materials of Joseph Bowring re PJM Capacity Market Forum Docket No. ADD23-7 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_PJM_Capacity_Market_Forum_Docket_No_AD23-7_20230615.pdf
June 14, 2023	Capacity Market Design Proposal: Sustainable Capacity Market (SCM) http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF_CIFP_Capacity_Market_Design_Proposal_20230613.pdf
June 28, 2023	IMM Proposal: Sustainable Capacity Market (SCM) http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_CIFP_Capacity_Market_Proposal_20230623.pdf
June 30, 2023	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2024/2025 and 2025/2026 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20230630.pdf
July 27, 2023	Sustainable Capacity Market Proposal Part 3 http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_Sustainable_Capacity_Market_Proposal_Part_3_20230727.pdf
August 16, 2023	Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM) http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf
August 18, 2023	IMM Comments on PJM CIFP Proposals http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RAST-CIFP_Comments_on_PJM_CIFP_proposals_20230818.pdf
September 29, 2023	Data Submission Window Opening for the 2024/2025 RPM Third Incremental Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening-2024-2025_Third_Incremental_Auction_20230929.pdf
September 29, 2023	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2024/2025 and 2025/2026 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20230928.pdf
October 19, 2023	IMM Answer and Motion for Leave to Answer re Capacity Accreditation Docket No. AD23-10 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_Docket_No_AD23-10_20231019.pdf
October 20, 2023	IMM Motions for Extension, Shortened Answer Period, and Expedited Action re CIFP and MSOC Docket Nos. ER24-98 and ER24-99 https://www.monitoringanalytics.com/filings/2023/IMM_Motion_for_Extension_ER24-98_ER24-99_20231020.pdf
October 24, 2023	IMM Answer to PJM Answer re CIFP Docket No. ER24-98 and ER24-99 https://www.monitoringanalytics.com/filings/2023/IMM_Answer_to_PJM_Answer_Docket_Nos_ER24-98-99_20231024.pdf
November 2, 2023	IMM Answer and Motion for Leave to Answer re CPower Complaint Docket No. EL23-104 https://www.monitoringanalytics.com/filings/2023/IMM_Answer_Docket_No_EL23-104_20231102.pdf
November 7, 2023	IMM Complaint re CIFP Docket No. EL24-12 https://www.monitoringanalytics.com/filings/2023/IMM_Complaint_Docket_No_EL24-12_20231107.pdf
November 9, 2023	IMM Protest re CIFP MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2023/IMM_Protest_re_CIFP_MSOC_Docket_No_ER24-98_20231109.pdf
November 9, 2023	IMM Protest re CIFP Energy Transition Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2023/IMM_Protest_re_CIFP_Energy_Transition_Docket_No_ER24-99_20231109.pdf
November 21, 2023	IMM Answer to PJM Answer re IMM CIFP Complaint Docket No. EL24-12 https://www.monitoringanalytics.com/filings/2023/IMM_Answer_to_Answer_Docket_No_EL24-12_20231121.pdf
November 29, 2023	IMM Determinations Posted for the PJM 2024/2025 RPM Third Incremental Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2024-2025_Third_Incremental_Auction_20231129.pdf
December 21, 2023	IMM Comments on Response to Deficiency Notice, Answer and Motion for Leave to Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2023/IMM_Comments_on_Def_Notice_Docket_No_ER24-99_20231221.pdf
December 22, 2023	IMM Comments on Response to Deficiency Notice, Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2023/IMM_Comments_on_Def_Notice_Docket_No_ER24-98_20231222.pdf
December 28, 2023	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2024/2025 and 2025/2026 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20231228.pdf
January 12, 2024	IMM Answer to PJM Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_ER24-99_20240112.pdf
January 14, 2024	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_-_2025-2026_Base_Residual_Auction_20240114.pdf
January 16, 2024	IMM Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Answer_Docket_No_ER24-98_20240116.pdf
January 24, 2024	IMM Answer to PJM Def Answer re PJM CIFP Docket No. ER24-99 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Def_Answer_Docket_No_ER24-99_20240124.pdf
January 25, 2024	IMM Answer and Motion for Leave to Answer re PJM MSOC Docket No. ER24-98 https://www.monitoringanalytics.com/filings/2024/IMM_Answer_to_PJM_Def_Answer_Docket_No_ER24-98_20240125.pdf

Installed Capacity

On January 1, 2023, RPM installed capacity was 183,388.8 MW (Table 5-3).[63] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 178,252.9 MW on December 31, 2023, a decrease of 5,135.9 MW or 2.8 percent from the January 1 level.[64 65] The 5,135.9 MW decrease was the net result of derates (1,927.4 MW), increases in exports (1,024.3 MW), decreases in imports (47.9 MW), and deactivations or changes in capacity resource status (7,309.0 MW), partially offset by new or reactivated generation (4,267.5 MW), and net capacity modifications (927.1 MW).

At the beginning of the new delivery year on June 1, 2023, RPM installed capacity was 176,984.4 MW, a decrease of 5,368.0 MW or 2.9 percent from the May 31, 2023, level of 182,352.4 MW. This change occurs as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2023[66]

	01-Jan-23		31-May-23		01-Jun-23		31-Dec-23	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	0.0	0.0%	0.0	0.0%	4.0	0.0%	21.9	0.0%
Coal	42,937.0	23.4%	42,054.0	23.1%	39,903.2	22.5%	38,910.3	21.8%
Gas	87,931.3	47.9%	89,790.3	49.2%	87,899.2	49.7%	87,818.9	49.3%
Hydroelectric	8,491.7	4.6%	8,480.4	4.7%	7,507.2	4.2%	7,507.2	4.2%
Nuclear	31,971.0	17.4%	31,823.8	17.5%	32,184.1	18.2%	32,183.0	18.1%
Oil	5,196.2	2.8%	5,160.2	2.8%	4,194.0	2.4%	4,371.4	2.5%
Solar	2,711.1	1.5%	2,806.5	1.5%	3,183.5	1.8%	3,513.3	2.0%
Solid waste	649.4	0.4%	627.4	0.3%	627.4	0.4%	627.4	0.4%
Wind	3,501.1	1.9%	1,609.8	0.9%	1,481.8	0.8%	3,321.4	1.9%
Total	183,388.8	100.0%	182,352.4	100.0%	176,984.4	100.0%	178,252.9	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2023, as well as the expected installed capacity for the 2023/2024 Delivery Year, based on the results of all auctions held through June 30, 2023.[67] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 22.4 percent on June 1, 2023, and is projected to decrease to 18.3 percent by June 1, 2024. The share of gas increased from 29.1 percent on June 1, 2007, to 50.1 percent on June 1, 2023, and is expected to increase to 54.0 percent on June 1, 2024.

63 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

64 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

65 Wind resources accounted for 3,321.4 MW, and solar resources accounted for 3,513.3 MW of installed capacity in PJM on December 31, 2023. Prior to the 2023/2024 Delivery Year, PJM administratively reduced the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data became available, unforced capability of wind and solar resources was be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 18 (July 26, 2023). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.

66 The ICAP MW for May 31, 2023, and June 1, 2023, were revised from the *2023 Quarterly State of the Market Report for PJM: January through June*. The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.

67 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2024

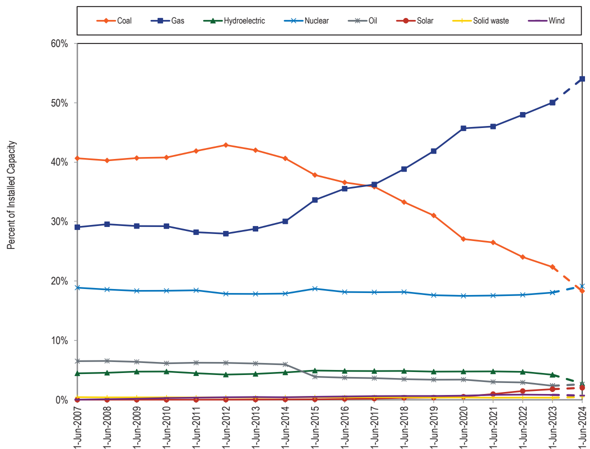


Table 5-4 shows the RPM installed capacity on January 1, 2023, through December 31, 2023, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and December 31, 2023

	01-Jan-23			31-May-23			01-Jun-23			31-Dec-23		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Constellation Energy Generation, LLC	20,417.8	13.6%	1	20,299.6	13.7%	1	20,184.7	14.1%	1	20,288.1	13.9%	1
ArcLight Capital Partners, LLC	14,230.1	9.5%	2	13,394.7	9.0%	2	12,339.7	8.6%	2	12,115.2	8.3%	2
LS Power Group	10,803.4	7.2%	3	11,638.7	7.9%	3	11,476.7	8.0%	3	11,486.7	7.9%	3
Riverstone Holdings LLC	10,370.4	6.9%	4	10,223.3	6.9%	4	10,169.0	7.1%	4	10,167.9	7.0%	4
Vistra Energy Corp.	8,671.5	5.8%	5	8,668.5	5.9%	5	8,669.4	6.1%	5	8,669.4	6.0%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2023, to December 31, 2023, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2023[68]

	01-Jan-23		31-May-23		01-Jun-23		31-Dec-23	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	135,714.9	74.0%	133,708.8	73.8%	129,896.9	74.0%	131,869.4	74.0%
Nonmarket	47,673.9	26.0%	47,409.6	26.2%	45,699.3	26.0%	46,405.4	26.0%
Total	183,388.8	100.0%	181,118.4	100.0%	175,596.2	100.0%	178,274.8	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[69] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. For all FDI calculations prior to June 1, 2023, the fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. Two additional resource types are included beginning in June 2023. Batteries were added to the resource mix

68 The ICAP MW for May 31, 2023, and June 1, 2023, were revised from the *2023 Quarterly State of the Market Report for PJM: January through June*.

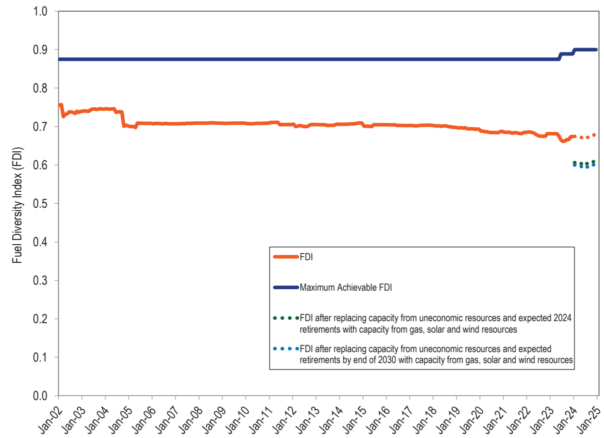
69 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

on June 1, 2023, and hybrid solar resources were added on January 1, 2024. The maximum achievable index with nine fuel types is 0.889. The maximum achievable index with ten fuel types is 0.900. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[70] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[71] The average FDI_c for 2023 decreased 1.1 percent compared to 2022. Figure 5-2 also includes the expected FDI_c through December 2024 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c was used to measure the impact on fuel diversity of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 57,694 MW of capacity are at risk of retirement, consisting of 4,285 MW currently planning to retire, 19,635 MW expected to retire for regulatory reasons and 33,744 MW expected to be uneconomic.[72] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2024 retirements were replaced by gas, wind and solar capacity.[73] The FDI_c under these assumptions would have been 10.1 percent lower than the actual FDI_c. The dotted blue line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected retirements through 2030 were replaced by gas, wind and solar capacity.[74] The counterfactual FDI_c in this scenario is 11.3 percent lower than the actual FDI_c.

70 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 Annual State of the Market Report for PJM* for additional details.
71 See the *2019 Annual State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.
72 See the *2023 Annual State of the Market Report for PJM*, Section 7: Net Revenue.
73 It is assumed that 2,670.4 MW of replacement capacity is from solar units and 250.7 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 13,640.8 GWh of generation in 2024 assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-36. This level of GWh represents the increase in renewable generation required by RPS in 2024 over the level of renewable generation that was required by RPS in 2023. The split between solar and wind is based on queue data.
74 It is assumed that 13,022.6 MW of replacement capacity is from solar units and 1,222.6 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 66,522.5 GWh of generation in 2030 assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-36. This level of GWh represents the increase in renewable generation required by RPS in 2030 over the level of renewable generation that was required by RPS in 2024. The split between solar and wind is based on queue data.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through September 1, 2024



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for intermittent and storage resources including hydro, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[75] In 2023, the 2023/2024 RPM Third Incremental Auction was conducted. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement. The 2025/2026 RPM Base Residual Auction was scheduled for June 2023 but postponed until June 2024.[76]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2022/2023 Delivery Year. The 17,459.0

75 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).
76 See 183 FERC ¶ 61,172 (2023).

MW increase was the result of new generation capacity resources (42,070.0 MW), reactivated generation capacity resources (1,380.4 MW), uprates (8,406.8 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (1,818.7 MW), offset by a net decrease in capacity imports (1,482.3 MW), deactivations (52,630.1 MW) and derates (4,072.0 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2019, through June 1, 2024, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margin for June 1, 2024, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity[77]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2022/2023 Delivery Year, internal installed capacity decreased by 4,844.9 MW after accounting for new capacity resources, reactivations, and uprates (51,857.2 MW) and capacity deactivations and derates (56,702.1 MW).

For the current and future delivery years (2023/2024 through 2024/2025), new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,978.6 MW) and pending deactivations (1,317.0 MW), PJM capacity is expected to increase by 1,661.6 MW for the 2023/2024 through 2024/2025 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2022/2023[78 79]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
2022/2023	4,743.2	0.0	417.0	0.0	(469.3)	(868.0)	7,460.5	294.7	(2,196.3)
Total	42,070.0	1,380.4	8,406.8	21,967.5	(1,482.3)	(1,818.7)	52,630.1	4,072.0	17,459.0

As shown in Table 5-7, total reserves on June 1, 2024, will be 25,073.2 MW, of which 4,761.4 MW (UCAP) are in excess of the required level of reserves, which is 20,311.8 MW (UCAP). In the 2024/2025 BRA, 18,133.0 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,772.3 MW of intermittent and storage resources (31.8 percent of the categorically exempt MW and 3.9 percent of total cleared MW) were not offered in the 2024/2025 BRA.

In the 2024/2025 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,319.3 MW, or 49.3 percent of the required reserves and 33.3 percent of total reserves. The

77 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

78 The capacity changes in this report are calculated based on June 1 through May 31.

79 The deactivations ICAP (MW) for 2022/2023 were revised from the *2023 Quarterly State of the Market Report for PJM: January through September.*

cleared MW of DR is 8,083.9 MW, or 47.9 percent of required reserves and 32.4 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves.

These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

Table 5-7 RPM reserve margin: June 1, 2019, to June 1, 2024[80 81 82]

	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	
Forecast peak load ICAP (MW)	151,643.5	148,355.3	149,482.9	149,263.6	149,382.2	151,639.1	A
FRR peak load ICAP (MW)	12,284.2	11,488.3	11,717.7	28,292.8	29,554.6	30,431.0	B
PRD ICAP (MW)	0.0	558.0	510.0	230.0	235.0	305.0	C
Installed reserve margin (IRM)	16.0%	15.5%	14.7%	14.9%	14.9%	17.7%	D
Pool wide average EFORd	6.08%	5.78%	5.22%	5.08%	4.87%	5.10%	E
Forecast pool requirement (FPR)	1.090	1.088	1.087	1.091	1.093	1.117	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	162,276.1	159,560.4	156,633.6	137,944.8	136,408.5	139,810.2	G
RPM committed less deficiency ICAP (MW) (generation and DR)	172,781.2	169,348.8	165,260.2	145,327.4	143,391.7	147,323.7	H=G/(1-E)
RPM peak load ICAP (MW)	139,359.3	136,309.0	137,255.2	120,740.8	119,592.6	120,903.1	J=A-B-C
Reserve margin ICAP (MW)	33,421.9	33,039.8	28,005.0	24,586.6	23,799.1	26,420.6	K=H-J
Reserve margin (%)	24.0%	24.2%	20.4%	20.4%	19.9%	21.9%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	11,124.4	11,911.9	7,828.5	6,596.3	5,979.8	5,020.8	M=K-D*J
Reserve margin in excess of IRM (%)	8.0%	8.7%	5.7%	5.5%	5.0%	4.2%	N=M/J
RPM peak load UCAP (MW)	130,886.3	128,430.3	130,090.5	114,607.2	113,768.4	114,737.0	P=J*(1-E)
RPM reliability requirement UCAP (MW)	151,832.0	148,331.5	149,210.1	131,679.9	130,714.7	135,048.8	Q=J*F
Reserve margin UCAP (MW)	31,389.8	31,130.1	26,543.1	23,337.6	22,640.1	25,073.2	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	10,444.1	11,228.9	7,423.5	6,264.9	5,693.8	4,761.4	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	T
Projected reserve margin	24.0%	24.2%	20.4%	20.4%	19.9%	21.9%	U=(H-T/(1-E))/J-1

Sources of Funding[83]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 43,450.4 MW (83.8 percent of all additions), with 33,507.2 MW from market funding and 9,043.2 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 8,406.8 MW (16.2 percent of all additions), with 5,964.3 MW from market funding and 2,442.5 MW from nonmarket funding. In summary, of the 51,857.2 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 39,471.5 MW (76.1 percent) were based on market funding.

Of the 3,824.1 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2023/2024 Delivery Year through the 2024/2025 Deliver Year, 2,432.6 MW are not yet in service.[84] Of those 2,432.6 MW that have not yet gone into service, 2,121.7 MW have market funding and 310.9 MW have nonmarket funding. Applying the historical completion rates, 65.2 percent of all the projects in development are expected to go into service (1,380.9 MW of the 2,121.7 MW of in development market funded projects; 206.2 MW of the 310.9 MW of in development nonmarket funded projects). Together, 1,587.1 MW of the 2,432.6 MW of generation capacity that cleared MW in RPM and are not yet in service are expected to go into service in the 2023/2024 through 2024/2025 Delivery Years.[85]

80 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
81 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
82 The reserve margin for June 1, 2023, was revised from the *2023 Quarterly State of the Market Report for PJM: January through June*.
83 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
84 Of the MW that cleared in RPM auctions for the 2023/2024 Delivery Year through the 2024/2025 Delivery Year, 10.5 MW have since been withdrawn from the PJM project queue.
85 See the *2023 Annual State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning.

Of the 1,391.5 MW of the additional generation capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years and are already in service, 1,162.9 MW (83.6 percent) are based on market funding and 228.6 MW (16.4 percent) are based on nonmarket funding.

In summary, 3,284.6 MW (85.9 percent) of the additional generation capacity (2,121.7 MW not yet in service and 1,162.9 MW in service) that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 539.5 MW (14.1 percent) of proposed generation that cleared the RPM auctions for the 2023/2024 through 2024/2025 Delivery Years.

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

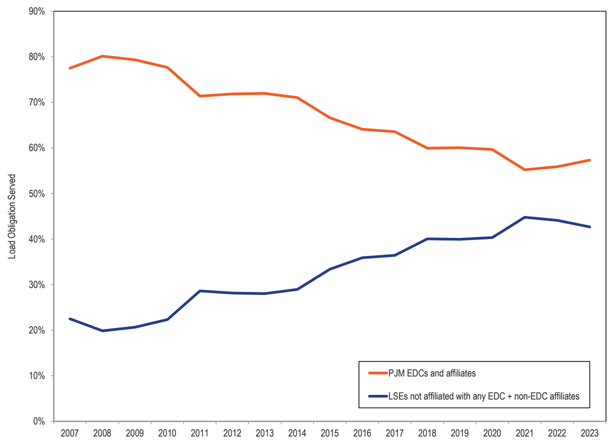
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2023, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 57.3 percent (Table 5-8), up from 55.9 percent on June 1, 2022. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 42.7 percent, down from 44.1 percent on June 1, 2022. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2023, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 57.3 percent on June 1, 2023. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 42.7 percent on June 1, 2023. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2022 and June 1, 2023

	01-Jun-22		01-Jun-23		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	100,803.7	55.9%	101,469.1	57.3%	665.4	1.4%
LSEs not affiliated with any EDC + non EDC Affiliates	79,537.6	44.1%	75,548.7	42.7%	(3,989.0)	(1.4%)
Total	180,341.3	100.0%	177,017.7	100.0%	(3,323.6)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2023



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted six months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[86] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2024/2025 RPM Base Residual Auction, BGE had 4,513.2 MW of CTRs with a total value of $38,728,614 and DPL had 544.7 MW of CTRs with a total value of $120,535. EMAAC, excluding DPL, had 3,704.1 MW of CTRs with a total value of $7,381,909 and DEOK had 3,015.4 MW of CTRs with a total value of $74,093,944.

MAAC had 1,026.2 MW of customer funded ICTRs with a total value of $7,704,472, EMAAC had 40.0 MW of customer funded ICTRs with a total value of $79,716, BGE had 65.7 MW of customer funded ICTRs with a total value of $563,782 and DEOK had 155.0 MW of customer funded ICTRs with a total value of $3,808,629.

MAAC had 486.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $3,651,831, EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $1,889,269 and BGE had 306.0 MW with a value of $2,625,832.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[87] Figure 5-4 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2024/2025 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate.[88]

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[89] PJM defines the

86 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 58 (Nov. 15, 2023).

87 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)]*.

88 See 117 FERC ¶ 61,331 (2006).

89 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

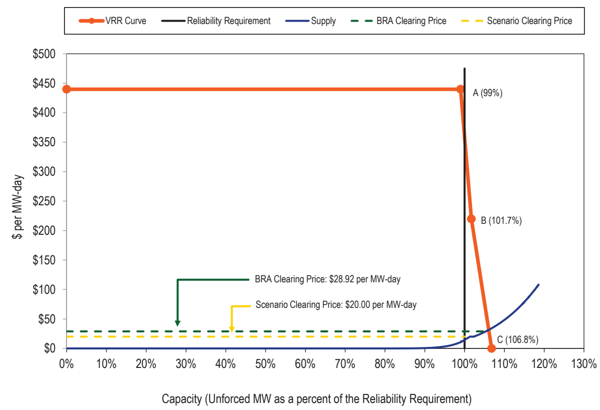
reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the 2024/2025 BRA. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve set equal to the reliability requirement.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,198,835,999. If PJM had used a vertical demand curve set equal to the reliability requirement for 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,381,442,645, a decrease of $817,393,354, or 37.2 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 59.2 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2024/2025 RPM BRA. The clearing price and cleared quantity would have been lower if a vertical VRR curve set at the reliability requirement had been used in place of the existing VRR curve. In the 2024/2025 BRA, the RTO clearing price would have decreased from $28.92 per MW-day to $20.00 per MW-day, and the clearing quantity would have decreased from 147,478.9 MW to 139,121.6 MW.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2024/2025 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2024/2025 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[90] In the 2023/2024 RPM Third Incremental Auctions, 36 participants out of 51 participants in the total PJM market passed the TPS test, eight participants out of 17 participants in the MAAC LDA market passed the TPS test, and all participants in the EMAAC and BGE LDA markets failed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[91 92 93]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the

90 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
91 See OATT Attachment DD § 6.5.
92 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
93 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2021/2022 through 2024/2025 RPM Auctions[94]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2022/2023 Third Incremental Auction				
RTO	0.68	0.50	43	43
MAAC	0.40	0.05	9	9
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

94 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[95] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[96] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[97] [98] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[99]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not

95 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
96 OATT Attachment DD § 5.10 (a) (ii).
97 146 FERC ¶ 61,052 (2014).
98 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Volume 2, Section 5, "Capacity Market" at "Locational Deliverability Areas (LDAs)".
99 OATT Attachment DD § 5.6.6(b).

equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[100]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[101] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[102] [103] [104] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[105]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[106] [107] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[108] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[109]

As shown in Table 5-10, of the 1,527.1 MW of imports offered in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.

100 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (Dec. 21, 2017).
101 161 FERC ¶ 61,197 (2017).
102 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
103 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 58 (Nov. 15, 2023).
104 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 58 (Nov. 15, 2023).
105 OATT Schedule 1 § 1.10.1A.
106 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
107 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 58 (Nov. 15, 2023).
108 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
109 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

Table 5-10 RPM imports: 2007/2008 through 2024/2025 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[110] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

There are two categories of demand side products included in the RPM market design.[111] Demand Resources (DR) are interruptible load resources that offer in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. Energy Efficiency (EE) Resources are load resources that offer in an RPM Auction and receive the relevant LDA or RTO resource clearing price but EE resources are not capacity resources.

Effective with the 2020/2021 Delivery Year, DR and EE include annual and summer products. Annual Demand Resources are required to be available on any day during the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period. Annual Energy Efficiency Resources are projects designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the relevant delivery year, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 Delivery Year, and EE resources should not be included in the capacity resources in any way as a result.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT. Summer-Period Energy Efficiency Resources are projects designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the HE 1500 EPT and the HE 1800 EPT from June through August, excluding weekends and federal holidays. EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 Delivery Year, and EE resources should not be included in the capacity resources in any way as a result.

110 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

111 See *2023 Annual State of the Market Report for PJM*, Volume 2, Section 6: Demand Response for more details on the definitions of DR and EE.

As shown in Table 5-11, Table 5-12, and Table 5-13, committed DR was 7,707.9 MW for June 1, 2023, as a result of cleared capacity for demand resources in RPM auctions for the 2023/2024 Delivery Year (8,174.1 MW) less replacement capacity (466.2 MW). Committed EE was 5,891.1 MW for June 1, 2023, as a result of cleared MW in RPM auctions for the 2023/2024 Delivery Year (5,896.4 MW) less replacement MW (5.3 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2020 to June 1, 2024[112 113 114]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,866.2	2,821.3	1,139.9	489.2	48.4	294.6	93.8	325.3	949.4	191.8	1,521.9	163.9	661.7	210.5	185.1
	EE cleared	5,734.8	2,303.6	1,265.3	499.4	53.5	431.0	201.6	287.5	485.0	55.9	792.6	211.9	312.4	129.4	186.8
	DR net replacements	(570.0)	(395.4)	(138.0)	(12.6)	1.7	(49.4)	(12.6)	(21.5)	(99.6)	(28.2)	127.5	8.9	(165.2)	(24.1)	24.3
	EE net replacements	(4.0)	11.8	7.0	14.9	0.0	(2.1)	15.4	8.7	(22.2)	(0.5)	0.0	6.2	(9.8)	(13.0)	0.0
	RPM load management	14,027.0	4,741.3	2,274.2	990.9	103.6	674.1	298.2	600.0	1,312.6	219.0	2,442.0	390.9	799.1	302.8	396.2
01-Jun-23	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3
	DR net replacements	(466.2)	(229.5)	(3.8)	(4.9)	22.8	3.4	2.6	(25.0)	47.2	(63.4)	160.7	20.1	(123.3)	(24.0)	25.0
	EE net replacements	(5.3)	(2.2)	(1.0)	7.6	9.0	11.6	13.7	7.6	(15.3)	(0.5)	(20.9)	0.0	(6.2)	(7.9)	0.7
	RPM load management	13,599.0	4,618.3	2,312.5	915.8	143.3	731.1	352.8	456.4	1,399.9	171.8	2,354.2	459.4	760.0	279.8	365.4
01-Jun-24	DR cleared	7,992.7	2,505.1	1,001.0	362.6	42.1	285.7	98.2	164.5	674.6	141.6	1,542.0	198.1	608.7	191.1	221.9
	EE cleared	7,668.7	3,500.1	2,030.3	779.2	99.9	771.4	376.1	398.9	587.3	54.9	1,063.4	380.3	392.9	128.3	188.1
	DR net replacements	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
	EE net replacements	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
	RPM load management	15,661.4	6,005.2	3,031.3	1,141.8	142.0	1,057.1	474.3	563.4	1,261.9	196.5	2,605.4	578.4	1,001.6	319.4	410.0

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2024[115 116 117 118]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	7,992.7	0.0	0.0	7,992.7	0.0	7,992.7	0.0	1.089	0.0

112 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
113 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
114 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.
115 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
116 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
117 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.
118 The Registered DR for June 1, 2022, were revised from the *2023 Quarterly State of the Market Report for PJM: January through September.*

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2024[119 120]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	5,734.8	0.0	(4.0)	5,730.8	0.0	5,730.8
01-Jun-23	5,896.4	0.0	(5.3)	5,891.1	(30.1)	5,861.0
01-Jun-24	7,668.7	0.0	0.0	7,668.7	0.0	7,668.7

Capacity Value of Intermittent Resources (ELCC)

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices at times of high intermittent output. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The contribution of intermittent and storage resources to reliability has been addressed in the PJM capacity market using derating factors in order to help ensure that MW of capacity are comparable, regardless of the source. Derating factors based on average generation during summer peak hours were used prior to the 2023/2024 Delivery Year to determine capacity values for wind and solar generators.[121] On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[122] The MMU opposed PJM's ELCC rules because they relied on significant counterfactual behavioral assumptions for storage and demand response resources, did not apply to all resource types, used invented (putative) data, used average technology values, were not locational, and provided for a long term guarantee of high average ELCC values for existing resources, among other issues.[123] PJM's ELCC approach is an ex ante, administrative determination by PJM based on a black box model, of the capacity value of resources. The ELCC values are on a class average technology class basis with no recognition of locational differences and no opportunity to recognize actual performance in the delivery year. PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability. Capacity values determined by the PJM average ELCC approach are being used for the 2023/2024 and 2024/2025 Delivery Years.

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability and consistent with a perfect resource, or at least a thermal resource. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources, currently credited with full capacity value, that are

119 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

120 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE addback rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

121 *Class Average Capacity Factors – Wind and Solar Resources*, PJM Interconnection L.L.C. (June 1, 2017).

122 See 176 FERC ¶ 61,056 (2021). There are multiple ways to apply the ELCC method. There is not a single ELCC method.

123 182 FERC ¶ 61,109 (2023).

much less available than some intermittent resources that are derated.

PJM's approach to ELCC is based on correct insights about the need to calculate the availability of different resource types but the actual implementation results in a set of illogical implications. For example, PJM assigned penalties to solar resources during Winter Storm Elliott in December 2022 when solar resources did not generate power after dark.

Under the PJM ELCC approach a solar resource is assigned a derating factor, the derated MW are equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of perfect capacity, meaning capacity that is always available at the derated level, even in the middle of the night.[124] As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of intermittent and storage resources, or for thermal resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[125]

The capacity derating factors applied to intermittent nameplate capacity the 2022/2023 Delivery Year and the ELCC calculations used for the 2023/2024 and the 2024/2025 Delivery Years are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity. The preferable solution is to require intermittent resources to purchase CIRs equal to the maximum energy output assumed in the derating calculation. That is the solution reached in the PJM stakeholder process.[126] The corresponding performance obligation of an intermittent resource is to produce at its corresponding maximum energy output level when it is possible, based on wind and solar conditions. After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[127]

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. There is the related issue of ensuring that intermittent resources, like all other resources, are required to pay their own interconnection costs in order to meet their attributed capacity value, consistent with the longstanding PJM market design, or reduce their capacity value.

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs).[128] If the intermittent resource or environmentally limited resource is deemed deliverable by PJM based on the additional CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year. Winter seasonal products have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. But this system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer.

124 "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection L.L.C. (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

125 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

126 ELCC/CIR discussions were held throughout 2022 during the PC Special Session – CIRs for ELCC Resources as well as the MC and the MRC <https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=83aadda8-b6c1-4630-9483-025b6b93fc28>.

127 183 FERC ¶61,009.

128 OATT Part VII, Subpart E § 332.

PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. Those CIRs are not available to be sold to or provided to intermittent resources because they have been paid for by annual resources. The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[129] [130] [131] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps are defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[132] For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

129 See OATT Attachment DD § 6.5.

130 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

131 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

132 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[133] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[134] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts, including RECs, and expected bonus performance payments/nonperformance charges.[135] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[136]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk

133 OATT Attachment DD § 6.8 (b).

134 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).

135 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

136 OATT Attachment DD § 6.8(a).

(CPQR).[137] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR), the resource's gross ACR, and the resource's forward looking net revenues. The gross ACR includes the cost to mitigate the resource's risk of incurring performance assessment penalties.

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel prices are a better guide to market expectations than historical energy and fuel prices. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices. The actual prices in 2022 are about 120 percent higher through the end of September than prices for the same period in 2021. The forward curves reflect this change, but the historical prices do not.

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 delivery year.[138] FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.[139] PJM's method for calculating forward looking E&AS net revenues was flawed for several reasons. PJM's method included an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[140]

More fundamentally, PJM's forward looking net revenue calculation tends to overestimate forward net revenues. The PJM method is based on a theoretical, unit by unit perfect dispatch based on unit parameters and forward fuel costs and LMPs. The PJM method fails to account for the realities of committing and dispatching units. Nonetheless, it remains correct that generation owners look forward and not backwards when calculating net revenues. The goal is an approach that retains the reality of historical commitment and dispatch while recognizing that future conditions will be different. A better approach would calculate unit forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel.

137 151 FERC ¶ 61,208 (2015).
138 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).

139 Forward energy and ancillary services (E&AS) revenue offsets were applicable from November 12, 2020, as approved in the FERC Order on compliance in Docket Nos. EL19-58-002 and EL19-58-003 until December 22, 2021, when the Commission issued an Order on Voluntary Remand in Docket Nos. EL19-58-006 and ER19-1486-003 reversing its prior determination that PJM should use a forward looking energy E&AS revenue offset and directing PJM to submit a compliance filing restoring the tariff provisions defining the historical E&AS revenue offset.
140 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 44 (Aug. 1, 2023).

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[141]

Under the original Capacity Performance design, the competitive offer of a resource was the larger of the asserted opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap based on its net ACR. But the default offer cap defined in the PJM tariff was based on strong assumptions that are not correct.

The circular logic of the offer cap derivation inevitably concluded that Net CONE times B was the competitive offer. The derivation is based on the assumption that Net CONE is the target clearing price for the capacity market. That assumption is the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, equals the market seller offer cap. The derivation is also based on the assumption that capacity resources have the ability to costlessly switch between capacity resource status and energy only status. That assumption is the basis for the assertion that an offer in the capacity market has an opportunity cost associated with the ability to be an energy only resource. But there is no such opportunity cost. The use of the offer cap is also based on a third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level.

141 OATT Attachment DD § 10A (d).

The offer cap derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

The PJM Capacity Market has a must offer requirement for a reason; it is required in order to ensure that the market can work, given the must buy obligation of load. A key ancillary benefit is that the must offer requirement helps prevent the exercise of market power by preventing withholding. The purpose of the must offer requirement is also to ensure equal and open access to the transmission system through CIRs (capacity interconnection rights). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. If a capacity market seller wants to convert to energy only status, the owner must give up its CIRs. Such CIRs are likely to be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market.

Net CONE times B was clearly well in excess of a competitive offer in the 2021/2022 BRA and 2022/2023 BRA whether compared to net ACR offers or compared to the actual offers of market participants. While the offer cap provided almost unlimited optionality to generation owners in setting offers, the actual clearing prices based on actual offers were generally about half of the offer caps. But some generation owners did successfully exercise market power within this design.

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.[142]

142 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).

2024/2025 RPM Base Residual Auction[143]

As shown in Table 5-14, 964 generation resources submitted offers in the 2024/2025 RPM Base Residual Auction. The MMU calculated unit specific ACR based offer caps for 21 generation resources (2.2 percent). Of the 964 generation capacity resources offered, 715 generation resources had default ACR based offer caps (74.2 percent), 21 generation resources had unit specific ACR based offer caps (2.2 percent), one generation resource had a unit specific opportunity cost based offer cap (0.1 percent), 17 Planned Generation Capacity Resources had uncapped offers (1.8 percent), five generation resources had uncapped planned uprates plus default ACR based offer caps for the existing portion of the units (0.5 percent), while the remaining 205 generation resources were price takers (21.3 percent). Market power mitigation was applied to 18 Capacity Performance sell offers.

2023/2024 RPM Third Incremental Auction

As shown in Table 5-14, 250 generation resources submitted Capacity Performance offers in the 2023/2024 RPM Third Incremental Auction. Unit specific offer caps were calculated for five generation resources (2.0 percent). Of the 250 generation resources, 177 generation resources elected the offer cap option of 1.1 times the BRA clearing price (70.8 percent), 48 generation resources had default ACR based offer caps (19.2 percent), four generation resources had unit specific ACR based offer caps (1.6 percent), one generation resource had a unit specific opportunity cost based offer cap (0.4 percent), two Planned Generation Capacity Resources had uncapped offers (0.8 percent), and the remaining 18 generation resources were price takers (7.2 percent). Market power mitigation was applied to five Capacity Performance sell offers.

Table 5-14 ACR statistics: RPM auctions held in 2023

	2024/2025 Base Residual Auction		2023/2024 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	715	74.2%	48	19.2%
Unit specific ACR (APIR)	14	1.5%	4	1.6%
Unit specific ACR (APIR and CPQR)	6	0.6%	0	0.0%
Unit specific ACR (non-APIR)	1	0.1%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	1	0.1%	1	0.4%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	177	70.8%
Uncapped planned uprate and default ACR	5	0.5%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	0	0.0%
Uncapped planned generation resources	17	1.8%	2	0.8%
Existing generation resources as price takers	205	21.3%	18	7.2%
Total Generation Capacity Resources offered	964	100.0%	250	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[144] The order is pending review before the U.S. Court of Appeals for the Sixth Circuit.[145] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject

143 See the "Analysis of the 2024/2025 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf> (October 30, 2023).
144 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).
145 Case No. 22-3176, et al.

to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[146] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[147]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[148] The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[149]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking E&AS offset to include forward looking energy and ancillary services revenues rather than historical.[150] The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.[151]

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-15, of the 471.8 ICAP MW of the MOPR Unit Specific Exception requests for the 2024/2025 RPM Base Residual Auction, the MMU agreed with requests for 267.0 MW. Of the 1,288.0 MW offered in the 2024/2025 RPM Base Residual Auction that were subject to MOPR, 1,164.0 MW cleared and 124.0 MW did not clear. There were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2023/2024 RPM Third Incremental Auction. There were no MW subject to MOPR in the 2023/2024 RPM Third Incremental Auction.

Table 5-15 MOPR statistics: RPM auctions held in 2023

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2024/2025 Base Residual Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	4	471.8	267.0	123.0	123.0	123.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	1,213.0	1,165.0	1,041.0
	Total		4	471.8	267.0	1,336.0	1,288.0	1,164.0
2023/2024 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	0.0	0.0	0.0
	Total		0	0.0	0.0	0.0	0.0	0.0

146 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
147 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
148 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).
149 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).
150 173 FERC ¶ 61,134 (2020).
151 177 FERC ¶ 61,209 (2021).

Replacement Capacity[152]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2024. The 2024 numbers are not final.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[153]

152 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

153 See Monitoring Analytics, LLC, "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2024[154]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(5,517.6)	144,626.3	(2,356.8)	142,269.5
01-Jun-24	147,505.6	0.0	0.0	147,505.6	0.0	147,505.6

Market Performance

Figure 5-5 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for the 2021/2022 through 2024/2025 Delivery Years for all RPM auctions held through 2023, and Table 5-18 shows the RPM cleared MW for the 2021/2022 through 2024/2025 Delivery Years for all RPM auctions held through 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.

Figure 5-6 shows the RPM cleared MW weighted average prices for each LDA from the 2021/2022 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through 2023. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through 2023 based on the unforced MW cleared and the resource clearing prices. For the 2022/2023 Delivery Year, RPM revenue was $4.0 billion. For the 2023/2024 Delivery Year, RPM revenue was $2.3 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through 2023. In 2022, RPM revenue was $6.2 billion. In 2023, RPM revenue was $3.0 billion.

Table 5-22 shows the RPM annual charges to load. For the 2022/2023 Delivery Year, annual charges to load were $4.0 billion. For the 2023/2024 Delivery Year, annual charges to load are $2.2 billion.

154 The RPM Commitment Shortage MW for June 1, 2023, were revised from the *2023 Quarterly State of the Market Report for PJM: January through September.*

Table 5-17 Capacity market clearing prices: 2021/2022 through 2024/2025 RPM Auctions

		RPM Clearing Price ($ per MW-day)													
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55
2022/2023 BRA	Capacity Performance	$50.09	$96.42	$50.09	$96.42	$97.75	$95.97	$97.75	$97.75	$97.75	$95.97	$50.09	$67.17	$107.92	$59.38
2022/2023 Third Incremental Auction	Capacity Performance	$50.05	$96.61	$50.05	$96.61	$97.93	$96.15	$97.93	$97.93	$97.93	$96.15	$50.05	$66.23	$108.22	$59.75
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$54.95	$49.49	$90.64	$54.95	$54.95	$49.49	$28.92	$28.92	$73.00	$28.92

Table 5-18 Capacity market cleared MW: 2021/2022 through 2024/2025 RPM Auctions[155]

		UCAP (MW)													
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3
2022/2023	THIRD	1,099.0	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	5,987.9
2023/2024	BASE	36,908.8	10,098.5	8,145.5	14,352.7	22,942.3	1,383.1	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	145,066.9
2023/2024	THIRD	315.7	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	5,077.0
2024/2025	BASE	37,406.8	10,855.5	8,874.0	14,184.9	23,151.1	1,444.7	2,665.3	3,494.3	3,433.8	9,720.6	25,156.1	5,056.5	2,062.1	147,505.6

Table 5-19 Weighted average clearing prices by zone: 2021/2022 through 2024/2025

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2021/2022	2022/2023	2023/2024	2024/2025
RTO				
AEP	$133.84	$49.35	$34.21	$28.92
APS	$133.84	$49.35	$34.21	$28.92
ATSI	$142.59	$48.89	$34.26	$28.92
Cleveland	$90.81	$49.41	$34.21	$28.92
COMED	$189.54	$63.70	$34.27	$28.92
DAY	$132.69	$49.16	$34.17	$28.92
DUKE	$127.66	$70.57	$34.24	$96.17
DUQ	$133.84	$49.35	$34.21	$28.92
DOM	$133.84	$49.35	$34.21	$28.92
EKPC	$133.84	$49.35	$34.21	$28.92
MAAC				
EMAAC				
ACEC	$158.72	$96.31	$52.21	$54.94
DPL	$158.72	$96.31	$52.21	$54.94
DPL South	$159.65	$97.41	$71.26	$90.64
JCPLC	$158.72	$96.31	$52.21	$54.94
PECO	$158.72	$96.31	$52.21	$54.94
PSEG	$184.82	$90.67	$50.71	$54.77
PSEG North	$190.48	$89.21	$50.73	$54.82
REC	$158.72	$96.31	$52.21	$54.94
SWMAAC				
BGE	$174.43	$119.73	$70.65	$72.99
PEPCO	$133.37	$94.75	$49.46	$49.44
WMAAC				
MEC	$134.56	$94.49	$49.49	$49.49
PE	$134.56	$94.49	$49.49	$49.49
PPL	$138.51	$95.29	$49.49	$49.48

155 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2024/2025[156]

Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.01	150,143.9	366	$2,308,670,914
2024/2025	$40.73	147,505.6	365	$2,192,828,381

Table 5-21 RPM revenue by calendar year: 2007 through 2025[157]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.56	150,036.3	365	$2,993,266,921
2024	$41.26	148,837.6	366	$2,244,450,576
2025	$40.73	61,022.9	151	$907,170,097

156 The results for the ATSI Integration Auctions are not included in this table.
157 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-5 History of capacity prices: 1999/2000 through 2024/2025[158]

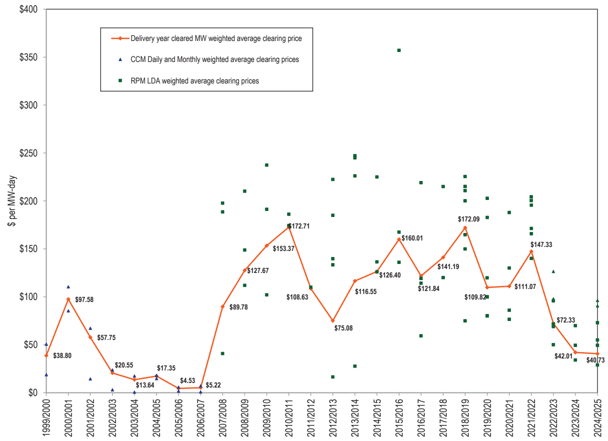
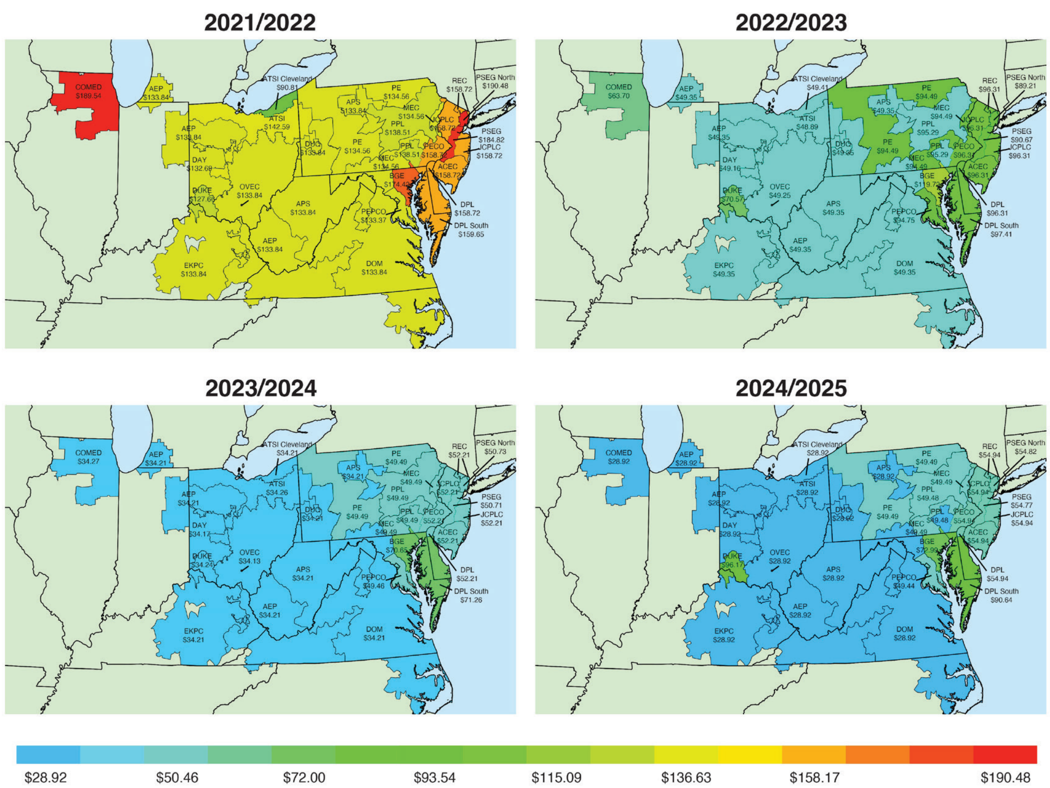


Figure 5-6 Map of RPM capacity prices: 2021/2022 through 2024/2025



158 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2024/2025 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Table 5-22 RPM cost to load: 2022/2023 through 2024/2025 RPM Auctions[159 160 161]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DEOK	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
Rest of EMAAC	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$28.99	76,450.4	$809,031,213
EMAAC	$54.50	31,332.0	$623,235,448
WMAAC	$49.68	22,302.1	$404,400,620
Rest of EMAAC	$66.07	4,607.4	$111,117,775
BGE	$59.83	7,556.5	$165,020,181
DEOK	$57.50	5,230.4	$109,776,921
Total		147,478.9	$2,222,582,158

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[162 163 164 165 166 167] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms,

159 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

160 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

161 The net load prices and obligation MW for 2024/2025 are not final.

162 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

163 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

164 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

165 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

166 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

167 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

CRF Issue[168]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[169] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[170] [171]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1-\frac{sB}{\sqrt{1+r}}-s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N-1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[172] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For example, Table 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[173] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2023/2024 would not apply to the calculation of APIR values for projects that go into service for the 2023/2024 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission stated that the issue is beyond the scope of the PJM filing.[174]

168 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
169 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
170 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
171 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.
172 Order 176 FERC ¶61,003 (July 2, 2021).
173 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.
174 Order 176 FERC ¶61,003 (July 2, 2021) at 28.

Table 5-24 Levelized CRF values: Delivery Year 2023/2024 through Delivery Year 2026/2027

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026	Levelized CRF 2026/2027
1 to 5	30	0.091	0.094	0.096	0.099
6 to 10	25	0.096	0.098	0.101	0.104
11 to 15	20	0.104	0.107	0.110	0.113
16 to 20	15	0.119	0.122	0.126	0.129
21 to 25	10	0.152	0.158	0.164	0.169
25 Plus	5	0.258	0.271	0.283	0.296
Mandatory CapEx	4	0.312	0.328	0.345	0.361
40 Plus Alternative	1	1.100	1.100	1.100	1.100

Table 5-25 Financial parameter and tax rate assumptions for CRF calculations

Financial Parameter	Parameter Value
Equity Funding Percent	45.000%
Debt Funding Percent	55.000%
Equity Rate	13.000%
Debt Interest Rate	6.000%
Federal Tax Rate	21.000%
State Tax Rate	9.300%
Effective Tax Rate	28.347%
After tax Weighted Average Cost of Capital	8.215%

The 2021 update to the CRF values was calculated using the weighted average cost of capital (WACC) model. The original CRF values, prior to 2021, were calculated using a flow to equity (FTE) model. The WACC model assumes a constant debt to equity ratio during the capital recovery period and therefore assumes that debt holders are paid more quickly than is required. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. Table 5-26 compares CRFs calculated under the two approaches using the assumptions in Table 5-25. The difference between the WACC CRF and FTE CRF is dependent upon the capital recovery term and the level of bonus depreciation. The WACC CRF exceeds the FTE CRF by 16.4 percent under 100 percent bonus depreciation with a 30 year cost recovery term. The FTE model is the correct approach because it accurately captures the cash flows during capital recovery over the defined financial life of the asset.

Table 5-26 Comparison of FTE and WACC CRFs

	WACC CRF						FTE CRF					
Capital Recovery	Bonus Percent						Bonus Percent					
Term (years)	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.296	0.312	0.328	0.345	0.361	0.377	0.289	0.307	0.324	0.342	0.360	0.377
5	0.246	0.258	0.271	0.283	0.296	0.308	0.238	0.252	0.266	0.280	0.294	0.308
10	0.147	0.152	0.158	0.164	0.169	0.175	0.138	0.145	0.153	0.160	0.168	0.175
15	0.116	0.119	0.122	0.126	0.129	0.132	0.105	0.111	0.116	0.122	0.127	0.133
20	0.101	0.104	0.107	0.110	0.113	0.115	0.090	0.095	0.100	0.105	0.110	0.115
25	0.093	0.096	0.098	0.101	0.104	0.106	0.081	0.086	0.091	0.096	0.100	0.105
30	0.088	0.091	0.094	0.096	0.099	0.101	0.076	0.081	0.085	0.090	0.095	0.099

	Absolute Change (WACC CRF less FTE CRF)						Relative Change					
Capital Recovery	Bonus Percent						Bonus Percent					
Term (years)	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.007	0.005	0.004	0.003	0.001	-0.000	2.3%	1.8%	1.2%	0.8%	0.3%	-0.1%
5	0.007	0.006	0.004	0.003	0.001	-0.000	3.1%	2.3%	1.6%	1.0%	0.4%	-0.1%
10	0.009	0.007	0.005	0.003	0.002	-0.000	6.5%	4.9%	3.4%	2.1%	0.9%	-0.2%
15	0.010	0.008	0.006	0.004	0.002	-0.000	9.5%	7.2%	5.0%	3.1%	1.3%	-0.3%
20	0.011	0.009	0.007	0.005	0.003	0.000	12.2%	9.3%	6.7%	4.4%	2.3%	0.4%
25	0.012	0.010	0.007	0.005	0.003	0.001	14.4%	11.2%	8.2%	5.6%	3.2%	1.1%
30	0.012	0.010	0.008	0.006	0.004	0.002	16.4%	12.8%	9.6%	6.7%	4.1%	1.7%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-27). The result is no change to the effective period between the notice and the retirement, if notice is provided on the last day of the submittal period, and an increase to six months notice, if notice is given on the first day of the submittal period.

Table 5-27 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following clendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[175] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[176]

Table 5-28 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through December 2023. Of the 170 deactivation requests submitted, 31 units (18.2 percent) deactivated an average of 157 days earlier than their initially requested date; 29 units (17.1 percent) deactivated an average of 106 days later than the originally requested deactivation date; and 66 units (38.8 percent) deactivated on their initially requested date. Eighteen (10.6 percent) of the unit deactivations were cancelled an average of 282 days before their scheduled deactivation date, and 26 (15.3 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-29 shows this information broken out by fuel types.

Table 5-28 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted 2018 through 2023

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	31	18.2%	(157)
Late	29	17.1%	106
On time	66	38.8%	0
Cancelled	18	10.6%	(282)
Pending	26	15.3%	-
Total	170	100.0%	-

175 OATT Attachment DD § 6.6(g).
176 OATT Part V §113.

Table 5-29 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through 2023

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	66.7%	(4)
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	1	33.3%	-
Total		3	100.0%	-
Coal	Early	15	31.3%	(169)
	Late	9	18.8%	78
	On time	15	31.3%	0
	Cancelled	4	8.3%	(371)
	Pending	5	10.4%	-
Total		48	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	5	83.3%	-
	Cancelled	0	0.0%	-
	Pending	1	16.7%	-
Total		6	100.0%	-
Methane	Early	4	16.0%	(107)
	Late	7	28.0%	71
	On time	10	40.0%	0
	Cancelled	2	8.0%	(190)
	Pending	2	8.0%	-
Total		25	100.0%	-
Natural Gas	Early	4	14.3%	(197)
	Late	6	21.4%	94
	On time	9	32.1%	0
	Cancelled	1	3.6%	-
	Pending	8	28.6%	-
Total		28	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
Total		10	100.0%	-
Oil	Early	3	7.1%	(218)
	Late	7	16.7%	188
	On time	22	52.4%	0
	Cancelled	1	2.4%	(105)
	Pending	9	21.4%	-
Total		42	100.0%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		1	100.0%	-
Storage	Early	3	42.9%	-
	Late	0	0.0%	-
	On time	4	57.1%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		7	100.0%	-

Part V Reliability Service

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[177] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. It is essential that the deactivation provisions of the tariff be evaluated and modified. The current approach to RMR service tends to suppress locational capacity market prices and provide the wrong price signal for either investing in the existing resource or investing in new resources to provide locational reliability.

To address that issue, the MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made.

If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. To address that issue, the MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions.

The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[178] It is essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. While not all retirements are completely foreseeable, improvement

177 OATT Part V §114.

178 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

is needed in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement.

The actual implementation of Part V provision of the tariff has resulted in overpayment of the RMR resources. It is essential that the compensation provisions of Part V of the tariff be modified to ensure payment of all but only the actual costs incurred by the generation owner to provide the service, plus an incentive.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[179] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[180] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service, generally only as an option in the event the unit is needed for reliability.[181] The PJM market rules do not require an owner to remain in service, but owners must provide advance notice of a proposed deactivation (See Table 5-27).[182] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[183] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[184]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[185] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[186] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[187] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[188] Project investment is capped at $2 million, above which FERC approval is required.[189] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[190]

The DACR is unnecessarily prescriptive about the nature of the incremental costs needed to provide service, includes unsupported escalation to extremely high incentive rates, and unnecessarily caps incremental investment at an arbitrary level.

Table 5-30 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022. Only two of eight owners have used the deactivation avoidable cost rate approach. The other six owners used the cost of service recovery rate. For units using the cost of service recovery rate option, revenues have averaged about 4.1 times the corresponding market price of capacity while for units using the deactivation avoidable cost rate, revenues have averaged about 1.6 times the corresponding market price of capacity.[191]

179 OATT § 113.2; OATT Attachment M § IV.1.
180 OATT § 113.2.
181 *Id.*
182 OATT § 113.1.
183 OATT Attachment DD § 6.6(g).
184 *Id.*
185 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
186 OATT § 115.
187 *Id.*
188 OATT § 118.
189 OATT §§ 115, 117.
190 OATT § 119.
191 The final rate for the Indian River 4 plant has not been established. The final rate could be lower or higher. The rate in the table is the actual cost to date of the RMR service.

Table 5-30 Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	31-Dec-26
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Table 5-31 Part V reliability service cost summary

		Initial Filing		Actual		Weighted Average RPM
Unit Names	Owner	Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	Clearing Price ($ per MW-day)
Indian River 4	NRG Power Marketing LLC	$357,065,662	$520.25	$133,249,790	$561.31	$51.68
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[192] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[193] [194] The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM.

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service which have generally been set through settlements.

192 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
193 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
194 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022)

This reliability service should be provided to PJM customers at reasonable rates, which reflect the relatively low risk nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends elimination of both the cost of service recovery rate in OATT Section 119 and the deactivation avoidable cost rate in Part V, and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-32 shows the capacity factors by unit type for 2022 and 2023. In 2023, nuclear units had a capacity factor of 95.7 percent, compared to 95.6 percent in 2022; combined cycle units had a capacity factor of 63.8 percent in 2023, compared to a capacity factor of 62.1 percent in 2022; coal units had a capacity factor of 33.4 percent in 2023, compared to 41.5 percent in 2022.

Table 5-32 Capacity factor (By unit type (GWh)): January through December, 2022 and 2023[195 196 197]

	2022		2023		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2023 from 2022
Battery	25.4	1.0%	28.3	1.1%	0.1%
Combined Cycle	303,298.0	62.1%	326,709.1	63.8%	1.8%
Single Fuel	263,325.8	68.4%	282,359.3	69.1%	0.7%
Dual Fuel	39,972.2	38.6%	44,349.8	43.1%	4.5%
Combustion Turbine	19,336.4	7.6%	21,483.0	8.5%	0.9%
Single Fuel	13,103.3	7.3%	16,405.1	9.2%	1.9%
Dual Fuel	6,233.1	8.2%	5,077.9	6.7%	(1.5%)
Diesel	431.1	12.2%	459.7	14.3%	2.1%
Single Fuel	390.0	12.3%	442.1	15.5%	3.2%
Dual Fuel	41.1	11.3%	17.6	4.8%	(6.4%)
Diesel (Landfill gas)	1,220.8	51.5%	1,028.6	49.8%	(1.6%)
Fuel Cell	208.7	85.5%	197.9	81.0%	(4.5%)
Nuclear	204,420.6	95.6%	273,488.6	95.7%	0.0%
Pumped Storage Hydro	6,343.8	18.7%	7,644.4	16.8%	(1.8%)
Run of River Hydro	7,864.8	37.2%	7,844.3	41.8%	4.6%
Solar	7,563.5	23.1%	10,954.7	18.6%	(4.5%)
Steam	174,323.6	38.3%	131,327.8	30.0%	(8.2%)
Biomass	5,515.6	69.9%	5,281.9	67.8%	(2.1%)
Coal	161,901.4	41.5%	117,622.6	33.4%	(8.1%)
Single Fuel	159,708.0	41.7%	117,622.6	33.4%	(8.3%)
Dual Fuel	2,193.4	30.9%	0.0	0.0%	(30.9%)
Natural Gas	5,942.5	41.8%	7,447.4	44.2%	2.4%
Single Fuel	521.2	51.3%	479.3	53.0%	1.7%
Dual Fuel	5,421.3	21.0%	6,968.0	23.4%	2.4%
Oil	964.1	4.3%	976.0	6.0%	1.7%
Wind	21,865.6	29.2%	28,781.5	28.2%	(1.0%)
Total	826,694.5	47.7%	809,948.0	47.0%	(0.6%)

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[198] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[199] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-7, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-7, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2023, the period runs from Monday, June 5 until Friday, September 1. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-10.

195 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
196 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
197 Hours in which batteries have net negative generation do not count toward their runtime.
198 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).
199 OATT, Attachment K (Appendix) § 1.9.3 (b).

Figure 5-7 Outages (MW): 2012 through 2023

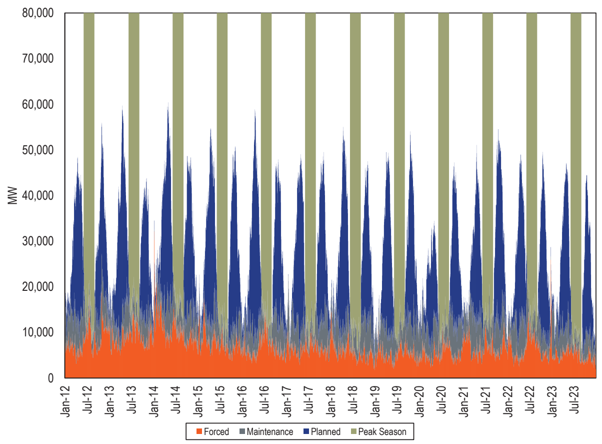
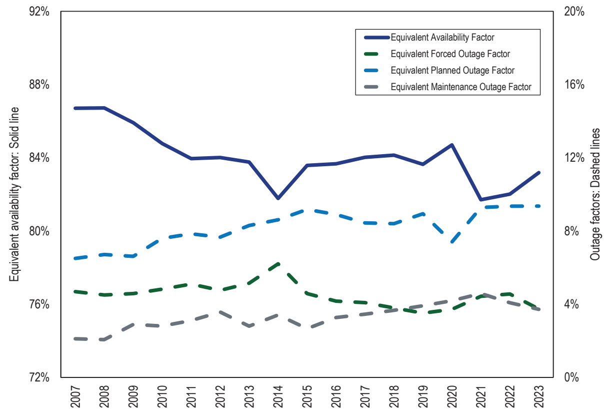


Figure 5-8 Equivalent outage and availability factors: 2007 to 2023



In 2023, forced outages were 24.6 percent lower, planned outages were 6.0 percent lower, and maintenance outages were 14.2 percent lower than in 2022.

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-8. Metrics by unit type are shown in Table 5-33.

Table 5-33 EFOF, EPOF, EMOF and EAF by unit type: 2007 to 2023

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.3%	8.5%	2.8%	81.4%	2.4%	6.1%	1.6%	89.9%	4.5%	2.5%	2.5%	90.5%	10.4%	0.6%	1.6%	87.4%
2008	7.5%	7.3%	2.5%	82.8%	2.3%	6.2%	1.5%	90.0%	2.9%	4.5%	2.2%	90.5%	9.3%	1.0%	1.2%	88.6%
2009	6.8%	8.4%	3.7%	81.1%	3.0%	6.8%	3.3%	86.9%	1.7%	2.7%	2.5%	93.1%	6.7%	0.6%	1.1%	91.6%
2010	8.1%	9.4%	4.1%	78.4%	2.9%	8.9%	3.2%	85.1%	2.1%	2.8%	2.1%	93.0%	4.5%	0.5%	1.5%	93.5%
2011	8.5%	9.1%	4.6%	77.9%	2.7%	9.6%	2.5%	85.2%	2.2%	3.7%	2.4%	91.7%	3.3%	0.1%	1.9%	94.7%
2012	7.8%	9.1%	6.0%	77.1%	3.0%	8.4%	2.3%	86.2%	2.7%	3.3%	1.6%	92.4%	3.9%	0.7%	2.5%	92.9%
2013	8.6%	10.5%	4.6%	76.4%	1.6%	9.4%	2.6%	86.4%	5.3%	4.4%	1.5%	88.8%	6.1%	0.3%	1.4%	92.3%
2014	10.1%	9.8%	5.5%	74.6%	2.5%	10.3%	2.4%	84.7%	6.7%	4.1%	1.7%	87.5%	14.2%	0.4%	2.1%	83.3%
2015	8.1%	10.6%	3.8%	77.5%	2.2%	10.4%	2.0%	85.4%	2.7%	4.7%	1.9%	90.6%	7.8%	0.3%	2.7%	89.2%
2016	7.8%	9.7%	5.7%	76.8%	2.8%	10.5%	1.8%	84.9%	2.0%	5.9%	2.0%	90.1%	5.3%	0.2%	2.6%	91.8%
2017	9.1%	11.0%	6.6%	73.2%	2.1%	10.0%	1.6%	86.3%	1.4%	5.9%	1.8%	90.9%	6.0%	0.4%	2.1%	91.6%
2018	8.6%	11.9%	6.8%	72.7%	1.4%	9.2%	1.4%	87.9%	1.9%	5.6%	1.8%	90.8%	6.2%	0.9%	3.4%	89.5%
2019	7.8%	10.7%	7.8%	73.8%	2.0%	10.7%	1.8%	85.5%	1.8%	7.0%	1.7%	89.6%	7.1%	0.9%	3.0%	89.0%
2020	5.2%	9.7%	9.2%	75.9%	3.6%	8.0%	2.3%	86.2%	1.7%	6.2%	2.0%	90.2%	6.6%	0.1%	3.1%	90.2%
2021	8.0%	15.1%	9.5%	67.4%	2.9%	9.9%	2.2%	85.0%	2.5%	6.1%	3.1%	88.4%	9.4%	0.5%	3.8%	86.3%
2022	9.1%	14.0%	8.8%	68.2%	3.4%	10.1%	1.8%	84.7%	2.9%	6.6%	2.4%	88.1%	10.8%	0.3%	4.3%	84.5%
2023	7.9%	13.6%	7.0%	71.6%	2.9%	11.6%	2.1%	83.4%	2.3%	6.6%	2.2%	88.9%	12.1%	0.3%	3.6%	84.0%

	Hydroelectric				Nuclear				Other				Total			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.2%	7.4%	1.5%	89.9%	1.4%	5.4%	0.3%	93.0%	5.3%	7.1%	3.3%	84.4%	4.7%	6.5%	2.1%	86.7%
2008	1.3%	8.2%	2.2%	88.3%	1.8%	5.1%	0.8%	92.3%	4.2%	11.0%	3.3%	81.4%	4.5%	6.7%	2.1%	86.7%
2009	2.4%	8.6%	2.4%	86.6%	4.2%	4.9%	0.6%	90.2%	3.1%	8.0%	5.0%	83.9%	4.6%	6.6%	2.9%	85.9%
2010	0.7%	8.3%	2.0%	89.0%	2.4%	5.6%	0.5%	91.6%	4.7%	10.5%	3.7%	81.2%	4.8%	7.6%	2.8%	84.8%
2011	1.6%	12.1%	1.9%	84.4%	2.7%	5.4%	1.2%	90.7%	5.1%	10.8%	3.3%	80.8%	5.1%	7.8%	3.1%	83.9%
2012	2.9%	5.8%	2.2%	89.1%	1.6%	6.3%	1.0%	91.1%	5.1%	12.0%	4.2%	78.7%	4.8%	7.7%	3.6%	84.0%
2013	2.3%	8.2%	2.0%	87.4%	0.9%	5.7%	0.6%	92.8%	6.2%	10.7%	3.4%	79.7%	5.1%	8.3%	2.8%	83.8%
2014	2.6%	9.7%	3.2%	84.6%	1.6%	5.5%	1.0%	92.0%	6.7%	16.2%	5.2%	71.9%	6.2%	8.6%	3.4%	81.8%
2015	3.9%	10.0%	1.5%	84.6%	1.4%	5.1%	1.4%	92.1%	6.0%	18.1%	4.3%	71.6%	4.6%	9.2%	2.7%	83.6%
2016	2.6%	7.9%	3.3%	86.2%	1.6%	5.5%	1.1%	91.8%	4.6%	16.6%	4.6%	74.2%	4.2%	8.9%	3.3%	83.7%
2017	2.1%	5.9%	3.2%	88.8%	0.5%	5.1%	0.7%	93.7%	4.8%	10.1%	5.7%	79.4%	4.1%	8.4%	3.5%	84.0%
2018	2.4%	7.7%	3.3%	86.6%	0.7%	4.7%	0.6%	94.0%	3.6%	9.1%	8.2%	79.0%	3.8%	8.4%	3.7%	84.1%
2019	1.4%	7.1%	3.9%	87.6%	0.6%	5.3%	0.9%	93.2%	3.5%	13.5%	6.7%	76.2%	3.5%	8.9%	3.9%	83.6%
2020	4.0%	6.9%	2.8%	86.2%	1.3%	4.8%	0.7%	93.2%	8.9%	7.8%	5.5%	77.8%	3.7%	7.4%	4.2%	84.7%
2021	8.5%	7.6%	3.0%	80.9%	1.0%	4.5%	1.2%	93.3%	6.7%	8.5%	6.6%	78.2%	4.4%	9.3%	4.6%	81.7%
2022	2.3%	8.7%	2.6%	86.4%	1.1%	5.2%	1.1%	92.6%	6.2%	9.6%	6.2%	77.9%	4.6%	9.4%	4.1%	82.0%
2023	3.3%	14.6%	3.7%	78.4%	0.7%	4.1%	1.6%	93.6%	4.5%	9.2%	6.8%	79.4%	3.7%	9.4%	3.7%	83.2%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[200] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in 2023 was 5.5 percent, a decrease from 7.9 percent in 2022. Figure 5-9 shows the average EFORd since 1999 for all units in PJM.[201]

200 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.

201 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2023 Annual State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Figure 5-9 Equivalent demand forced outage rates (EFORd): 1999 to 2023

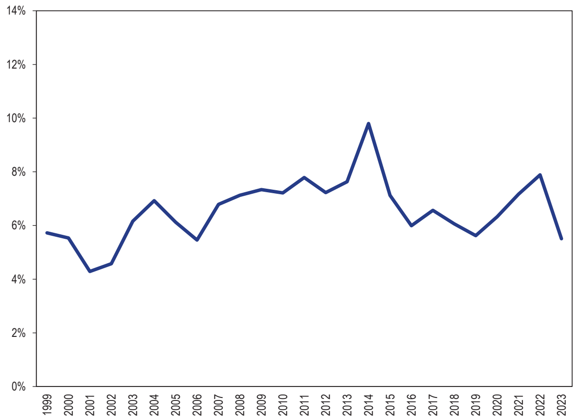


Table 5-34 shows the class average EFORd by unit type.

Table 5-34 EFORd by unit type: 2007 to 2023

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	8.3%	8.6%	8.5%	9.8%	10.9%	10.5%	11.1%	12.9%	9.7%	9.7%	11.8%	11.4%	10.7%	8.7%	11.8%	12.9%	11.5%
Combined Cycle	4.2%	4.2%	4.7%	4.2%	3.8%	3.8%	2.4%	4.5%	3.0%	3.5%	2.7%	2.2%	2.8%	4.2%	3.8%	4.5%	3.7%
Combustion Turbine	11.7%	11.9%	10.5%	9.9%	8.8%	8.2%	11.1%	16.8%	9.2%	5.6%	5.4%	6.2%	5.4%	4.3%	5.5%	8.9%	5.0%
Diesel	12.0%	10.4%	9.4%	6.5%	9.3%	4.9%	6.7%	15.2%	9.1%	6.9%	6.9%	6.8%	7.7%	7.8%	11.8%	14.4%	14.0%
Hydroelectric	2.0%	2.0%	3.3%	1.2%	2.8%	4.5%	3.7%	4.0%	5.5%	3.8%	3.1%	3.2%	1.9%	5.4%	10.6%	3.3%	4.6%
Nuclear	1.4%	2.0%	4.3%	2.6%	2.9%	1.8%	1.0%	1.8%	1.5%	1.8%	0.5%	0.8%	0.6%	1.4%	1.1%	1.2%	0.8%
Other	9.3%	9.9%	8.4%	7.8%	10.1%	9.0%	10.9%	13.3%	13.2%	9.2%	13.7%	9.2%	9.2%	19.5%	17.3%	17.3%	6.1%
Total	6.8%	7.1%	7.3%	7.2%	7.8%	7.2%	7.6%	9.8%	7.1%	6.0%	6.6%	6.1%	5.6%	6.3%	7.2%	7.9%	5.5%

EFORd vs EAF

EFORd is not an adequate measure of units' availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[202] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-35 shows the differences between EFORd and EAF by unit type.

Table 5-35 EFORd and EAF by unit type: 2012 to 2023

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	10.5%	22.9%	3.8%	13.8%	8.2%	7.6%	4.9%	7.1%	4.5%	10.9%	1.8%	8.9%	9.0%	21.3%	7.2%	16.0%
2013	11.1%	23.6%	2.4%	13.6%	11.1%	11.2%	6.7%	7.7%	3.7%	12.6%	1.0%	7.2%	10.9%	20.3%	7.6%	16.2%
2014	12.9%	25.4%	4.5%	15.3%	16.8%	12.5%	15.2%	16.7%	4.0%	15.4%	1.8%	8.0%	13.3%	28.1%	9.8%	18.2%
2015	9.7%	22.5%	3.0%	14.6%	9.2%	9.4%	9.1%	10.8%	5.5%	15.4%	1.5%	7.9%	13.2%	28.4%	7.1%	16.4%
2016	9.7%	23.2%	3.5%	15.1%	5.6%	9.9%	6.9%	8.2%	3.8%	13.8%	1.8%	8.2%	9.2%	25.8%	6.0%	16.3%
2017	11.8%	26.8%	2.7%	13.7%	5.4%	9.1%	6.9%	8.4%	3.1%	11.2%	0.5%	6.3%	13.7%	20.6%	6.6%	16.0%
2018	11.4%	27.3%	2.2%	12.1%	6.2%	9.2%	6.8%	10.5%	3.2%	13.4%	0.8%	6.0%	9.2%	21.0%	6.1%	15.9%
2019	10.7%	26.2%	2.8%	14.5%	5.4%	10.4%	7.7%	11.0%	1.9%	12.4%	0.6%	6.8%	9.2%	23.8%	5.6%	16.4%
2020	8.7%	24.1%	4.2%	13.8%	4.3%	9.8%	7.8%	9.8%	5.4%	13.8%	1.4%	6.8%	19.5%	22.2%	6.3%	15.3%
2021	11.8%	32.6%	3.8%	15.0%	5.5%	11.6%	11.8%	13.7%	10.6%	19.1%	1.1%	6.7%	17.3%	21.8%	7.2%	18.3%
2022	12.9%	31.8%	4.5%	15.3%	8.9%	11.9%	14.4%	15.5%	3.3%	13.6%	1.2%	7.4%	17.3%	22.1%	7.9%	18.0%
2023	11.5%	28.4%	3.7%	16.6%	5.0%	11.1%	14.0%	16.0%	4.6%	21.6%	0.8%	6.4%	6.1%	20.6%	5.5%	16.8%
Average	11.1%	26.2%	3.4%	14.5%	7.6%	10.3%	9.3%	11.3%	4.5%	14.4%	1.2%	7.2%	12.3%	23.0%	6.9%	16.6%

202 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[203] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 3.7 percent in 2023. Table 5-36 shows the causes of EFOF by unit type. Forced outages for unit testing, 15.8 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types, although boiler tube leaks and boiler air and gas systems were the largest contributors to EFOF for coal plants.

Table 5-36 Contribution to PJM EFOF by unit type by cause: 2023

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Unit Testing	4.6%	19.8%	27.5%	30.4%	54.7%	21.4%	35.6%	15.8%
Boiler Tube Leaks	19.4%	5.0%	0.0%	0.0%	0.0%	0.0%	7.8%	11.9%
Boiler Air and Gas Systems	19.6%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%	10.7%
Electrical	1.6%	29.0%	5.4%	6.9%	3.9%	4.0%	4.0%	7.1%
Regulatory	12.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	6.5%
Feedwater System	4.9%	0.8%	0.0%	0.0%	0.0%	3.1%	3.8%	3.2%
Generator	2.7%	0.8%	12.4%	0.2%	0.8%	3.4%	0.2%	3.1%
Low Pressure Turbine	4.5%	1.1%	0.0%	0.0%	0.0%	0.0%	0.1%	2.6%
Turbine	0.0%	0.6%	11.1%	0.0%	21.5%	0.0%	0.0%	2.3%
Miscellaneous (Gas Turbine)	0.0%	4.9%	13.8%	0.0%	0.0%	0.0%	0.0%	2.3%
Controls	0.8%	6.0%	1.1%	3.4%	0.2%	7.4%	3.7%	2.3%
Auxiliary Systems	1.6%	2.0%	6.1%	0.0%	0.0%	0.0%	0.7%	1.9%
Miscellaneous (Steam Turbine)	0.7%	3.4%	0.0%	0.0%	0.0%	0.0%	9.7%	1.8%
Circulating Water Systems	1.0%	6.6%	0.0%	0.0%	0.0%	0.3%	0.1%	1.7%
Boiler Fuel Supply from Bunkers to Boiler	2.9%	0.1%	0.0%	0.0%	0.0%	0.0%	1.0%	1.7%
High Pressure Turbine	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	1.6%
Wet Scrubbers	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
Fuel, Ignition and Combustion Systems	0.0%	3.8%	7.5%	0.0%	0.0%	0.0%	0.0%	1.5%
NOx Reduction Systems	2.3%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
All Other Causes	15.3%	15.7%	15.1%	59.1%	18.9%	60.4%	29.9%	19.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

203 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EMOF was 3.7 percent in 2023. Table 5-37 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 10.7 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EMOF for combustion turbines.

Table 5-37 Contribution to EMOF by unit type by cause: 2023

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	16.3%	13.6%	0.0%	0.0%	0.0%	0.0%	8.8%	10.7%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	66.5%	0.0%	6.7%
Boiler Air and Gas Systems	12.3%	0.1%	0.0%	0.0%	0.0%	0.0%	1.8%	6.3%
Electrical	4.8%	6.7%	10.1%	2.7%	20.7%	0.0%	8.4%	6.3%
Boiler Overhaul and Inspections	7.1%	1.1%	0.0%	0.0%	0.0%	0.0%	8.5%	4.8%
Miscellaneous (Gas Turbine)	0.0%	14.1%	23.5%	0.0%	0.0%	0.0%	0.0%	4.1%
Wet Scrubbers	8.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%
Boiler Piping System	3.6%	13.4%	0.0%	0.0%	0.0%	0.0%	3.6%	3.8%
NOx Reduction Systems	7.2%	1.2%	0.2%	0.0%	0.0%	0.0%	0.0%	3.7%
Valves	5.7%	2.5%	0.0%	0.0%	0.0%	0.8%	0.6%	3.3%
Miscellaneous (Steam Turbine)	0.7%	1.5%	0.0%	0.0%	0.0%	0.4%	18.4%	3.1%
Condensing System	2.3%	8.9%	0.0%	0.0%	0.0%	0.6%	3.9%	2.7%
Boiler Fuel Supply from Bunkers to Boiler	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	9.3%	2.7%
Miscellaneous (Boiler)	1.1%	1.1%	0.0%	0.0%	0.0%	0.0%	13.8%	2.6%
Water Supply/Discharge	0.0%	0.0%	0.0%	0.0%	52.6%	0.0%	0.0%	2.5%
Circulating Water Systems	4.1%	2.0%	0.0%	0.0%	0.0%	0.3%	1.2%	2.5%
Miscellaneous (Balance of Plant)	2.0%	6.1%	3.9%	0.3%	0.3%	0.0%	0.0%	2.1%
Auxiliary Systems	0.9%	2.7%	9.4%	0.0%	0.2%	0.0%	0.0%	1.8%
Feedwater System	2.6%	1.8%	0.0%	0.0%	0.0%	0.4%	1.1%	1.7%
All Other Causes	18.2%	23.1%	52.9%	97.1%	26.3%	31.0%	20.6%	24.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 9.4 percent in 2023. Table 5-38 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant issues, 20.4 percent of the system EPOF, were the largest single contributor to average system EPOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EPOF for combined cycles and combustion turbines.

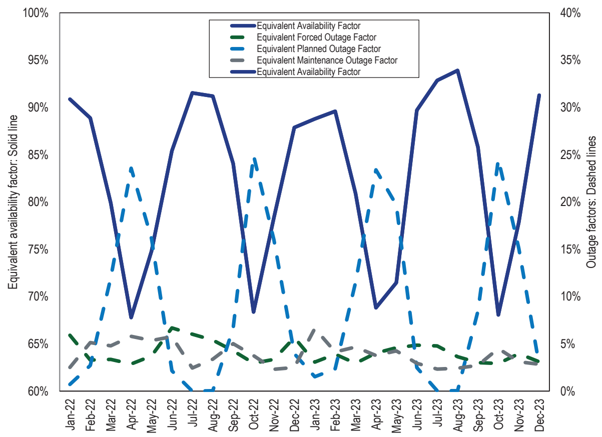
Table 5-38 Contribution to EPOF by unit type and cause: 2023

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Gas Turbine)	0.0%	50.9%	63.7%	0.0%	0.0%	0.0%	0.0%	20.4%
Miscellaneous (Balance of Plant)	25.5%	20.9%	14.7%	0.0%	0.1%	0.0%	17.9%	17.8%
Boiler Overhaul and Inspections	24.9%	4.0%	0.0%	0.0%	0.0%	0.0%	40.8%	13.3%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	98.8%	0.0%	10.1%
Miscellaneous (Steam Turbine)	7.6%	18.2%	0.0%	0.0%	0.0%	0.0%	0.6%	7.3%
Miscellaneous (Generator)	7.3%	0.2%	6.3%	0.0%	29.8%	0.0%	0.0%	6.0%
Boiler Air and Gas Systems	8.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	28.7%	0.0%	0.0%	2.3%
Wet Scrubbers	6.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%
Low Pressure Turbine	4.3%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%
Exciter	0.0%	0.0%	0.0%	0.0%	20.5%	0.0%	0.0%	1.7%
Miscellaneous Boiler Tube Problems	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	1.2%
Miscellaneous (Pollution Control Equipment)	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	9.4%	1.2%
Turbine	0.0%	0.4%	0.0%	0.0%	11.7%	0.0%	0.0%	1.1%
Valves	2.2%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Stack Emission	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Electrical	0.0%	0.1%	2.2%	0.0%	0.0%	0.0%	8.3%	0.9%
Slag and Ash Removal	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Generator	0.0%	0.0%	2.8%	0.0%	5.3%	0.0%	0.4%	0.8%
All Other Causes	3.8%	3.8%	10.2%	100.0%	3.8%	1.2%	22.5%	5.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-10.

Figure 5-10 Monthly generator performance factors: 2022 through 2023



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[204] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[205] Wind and solar resources do not perform verification tests to prove capability.[206]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[207]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[208] There were no such charges assessed for 2023.

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[209]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by power meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have

204 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 57 (July 26, 2023).
205 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 57 (July 26, 2023).
206 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 57 (July 26, 2023).
207 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.
208 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 57 (July 26, 2023).
209 OATT, Attachment DD (Reliability Pricing Model) § 7.

the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[210] In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM total nonperformance charges were approximately $1.796 billion, reduced to $1.226 billion in a settlement agreement.[211] There were no such charges assessed in 2023.

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[212] [213] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[214] [215] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 64 resources were assessed for deficiency charges in 2022, and 175 resources were assessed for deficiency charges in 2023.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014. Table 5-39 shows that from 2014 through 2023, of all the changes in outage status, 96.4 percent of the outages and 87.5 percent of the outage MWh were changed from either planned or maintenance to forced outage status. Of those changes to forced outage status, 40.0 percent of the outages and 74.6 percent of the MWh were for coal and hydro plants.

210 OATT, Attachment DD (Reliability Pricing Model) § 10A.
211 See Settlement Agreement, Docket No. ER23-2975-000 (September 29, 2023), which can be accessed at: <https://pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx>.
212 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 18 (July 26, 2023. 1, 2021).
213 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
214 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 57 (July 26, 2023).
215 OATT, Attachment DD (Reliability Pricing Model) § 8.

Table 5-39 Changed outages by unit type: 2014 through 2023[216]

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
Coal	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	170,807
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	1	13,211	0	NA	0	NA
	Total	13	786,990	0	NA	233	5,736,526
	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
Combined Cycle	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022	0	NA	1	3,817	2	208
	2023	0	NA	0	NA	0	NA
	Total	7	34,690	11	373,648	89	743,650
	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
Combustion Turbine	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023	0	NA	0	NA	2	270,221
	Total	9	26,990	6	57,104	194	562,290
	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
Diesel	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	27,059
	2022	4	5,492	0	NA	10	305
	2023	0	NA	0	NA	0	NA
	Total	28	6,147	0	NA	1,300	82,408
	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
Hydroelectric	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	281,976
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023	0	NA	0	NA	9	196,512
	Total	12	135,420	0	NA	922	5,669,622
	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
Nuclear	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	0	NA	0	NA	0	NA
	Total	0	NA	2	178,191	2	22,903
	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
Other	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023	2	17,023	0	NA	0	NA
	Total	14	269,134	2	37,294	47	566,132

216 Year describes the year in which the outage started and not the year in which the outage designation was changed.

Table 5-39 Changed outages by unit type: 2014 through 2023 (continued)

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,324,165
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	624,398
	2021	3	137	7	303,061	41	315,679
	2022	4	5,492	1	3,817	18	30,896
	2023	3	30,234	0	NA	11	466,733
	Total	83	1,259,370	21	646,237	2,787	13,383,531

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for reconciliation of its power supply cost recovery plan (Case No. U-21261) for the twelve months ending December 31, 2023.	U-21262

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Devi Glick on behalf of Attorney General Dana Nessel, Citizens Utility Board of Michigan, and Sierra Club (Exhibits CUB-1 through CUB-20)** was served on the following:

Name/Party	E-mail Address
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The statements above are true to the best of my knowledge, information and belief.

TROPOSPHERE LEGAL, PLLC
Counsel for CUB & Sierra Club

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for reconciliation of its power supply cost recovery plan (Case No. U-21261) for the twelve months ending December 31, 2023.	U-21262

CONFIDENTIAL
PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Devi Glick on behalf of Attorney General Dana Nessel, Citizens Utility Board of Michigan, and Sierra Club (Exhibits CUB-1 through CUB-20)** was served on the following:

Name/Party	E-mail Address
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The statements above are true to the best of my knowledge, information and belief.

TROPOSPHERE LEGAL, PLLC
Counsel for CUB & Sierra Club

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