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April 17, 2023

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Dear Ms. Felice:

Re: MPSC Case No. U-20805

Enclosed find the ***Attorney General's Testimony and PUBLIC Exhibits of Devi Glick,*** and related Proof of Service.

Sincerely,

Christopher M Bzdok

Digitally signed by Christopher M Bzdok
Date: 2023.04.17 16:34:04 -04'00'

Christopher Bzdok
Special Assistant Attorney General

cc: All Parties

PROOF OF SERVICE - U-20805

The undersigned certifies that a copy of the ***Attorney General's Testimony and PUBLIC Exhibits of Devi Glick*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 17th day of April 2023.

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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	)	**Case No. U-20805**
proceeding for the 12-month period ended	)	
December 31, 2021.	)	

Direct Testimony of Devi Glick

On Behalf of the Attorney General of Michigan

April 17, 2023

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

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

Q Please describe Synapse Energy Economics.

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

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

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as widely used optimization and electric dispatch models. I have directly run 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 10 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit AG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Dana Nessel, Attorney General of Michigan.

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, and Case No. I-21261, I&M's 2023 PSCR Plant 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 2021. Second, I evaluate I&M's request to recover costs paid to AEP Generation ("AEG") in 2021 for power generated by AEG's portion of Rockport Units 1 and 2. Third, I review the fuel and power purchase costs for I&M's owned share of the Rockport units that it plans to pass on to customers for 2021.

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 2021. 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 2021, far above market, for the portion of Rockport's power that it 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 Plant 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.

2. Findings and Recommendations

Q Please summarize your findings.

A My primary findings are:

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 2021, the ICPA cost I&M customers $14.2 million more than the cost of equivalent energy and capacity purchased from the market, and more than the cost of other available benchmarks.

2. I&M paid its affiliate AEG for a portion of AEG's share of the Rockport units at a cost that was far in excess of market value. Over the course of 2021, the UPA cost I&M customers $114.2 million more than the cost of equivalent energy and capacity purchased from the market, and more than the cost of other available benchmarks.

Q Please summarize your recommendations.

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

1. The Commission should disallow in this proceeding $2.0 million, which is Michigan's jurisdictional share of the total $14.2 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 2021.

2. The Commission should disallow in this proceeding $15.9 million, which is Michigan's jurisdictional share of the total $114.2 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 2021).

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

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

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

A OVEC is 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. The Company 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 What portion of OVEC is I&M responsible for?

A I&M's share of the ICPA with OVEC is 7.85 percent.[3] 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 174–174.3 MW. 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.[4] The Clifty Creek and Kyger Creek Plants will each be 85 years old by the time the ICPA expires in 2040.[5]

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[1] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2021 (Pg. 1).
[2] Commission Order dated May 13, 2021 in Case No. U-20529, Pg. 17.
[3] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2021 (p. 1).
[4] Commission Order dated May 13, 2021 in Case No. U-20529, Pg. 13.
[5] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2021 (p. 1).

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

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.

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 based on the total value of the services it provides?

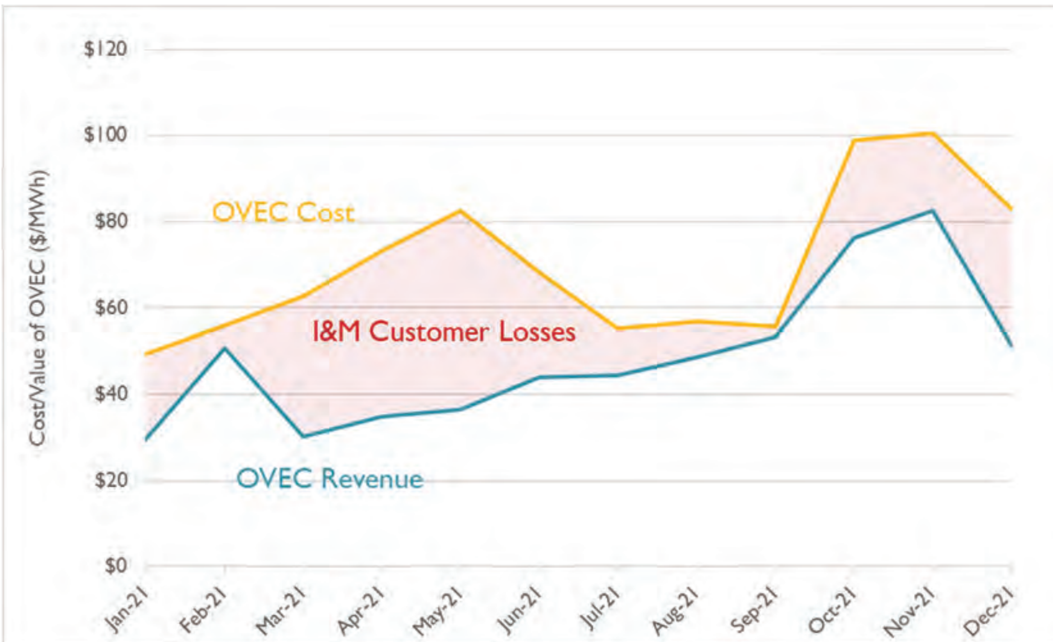
A No. I find that in 2021, while I&M was billed $64.10/MWh[6] under the ICPA for the energy and capacity from OVEC, the power was only worth $46.11/MWh in the market. This is based on a comparison of (1) the energy and demand charges billed to Sponsoring

[6] Exhibit IM-5 (JMS-1) Pg. 1.

Companies[7] under the ICPA and (2) the value of the energy and capacity provided by OVEC if I&M sold those services into the PJM energy and capacity markets.[8]

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 2021, I&M ratepayers were paying significantly more for OVEC services than the equivalent market value of the services.

Figure 1. All-in OVEC cost / value for energy and capacity (2021)



Source: Ex AG-3, I&M Response to Attorney General 1-07; Ex AG-5, I&M Response to Staff 2-01, Attachment 5; Ex AG-4, 2022 State of the Market Report for PJM (p.336): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec5.pdf.

The total difference between what OVEC was charging I&M and the value of the power works out to a net loss of $14.2 million in 2021 that I&M customers are being asked to pay while receiving no additional value.

[7] 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.

[8] Ex AG-3, I&M Response to Attorney General Request 1-07; Ex AG-4, 2022 State of the Market Report for PJM (p. 336): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec5.pdf.

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

A I&M provided the monthly billing from OVEC for 2021 which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[9] Based on this billing data, OVEC charged I&M $51,934,879 for 790,000 MWh of electricity, for an average cost of $65.74 per MWh (this is slightly different than what is shown in Exhibit IM-4, page 3 line 13). To isolate just the energy and demand charges, I removed the transmission and PJM expenses and fees and ancillary charges. This results in a total of $50,640,421 for an average cost of $64.10/MWh.

The Company also provided energy revenue data by month which showed that the Company earned $29,480,487 in energy market revenues from the sale of OVEC power into the PJM market.[10] That works out to an average energy value of $37.32/MWh. Using the installed capacity values for 2021 (174 MW in January–May, and 174.3 MW June–December),[11] 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 $74/MW-day for the first half of 2021 and $134/MW-day for the second half of the year.[12] This works out to an average capacity value of only $8.79/MWh. The combined energy and capacity value of OVEC's power in the PJM market at $46.11/MWh[13] 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 2021 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. As shown in Table 1 below, this is not a new occurrence or a single-year

[9] Ex AG-5, I&M Response to Staff Request 2-01, Attachment 5.
[10] Ex AG-3, I&M Response to Attorney General Request 1-07.
[11] Ex AG-6, I&M Response to Sierra Club Request 4.7, Case No. U-20804.
[12] Ex AG-4, 2022 State of the Market Report for PJM (p.336): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec5.pdf.
[13] Ex AG-3, I&M Response to Attorney General Request 1-07; Ex AG-4, 2022 State of the Market Report for PJM (p.336): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec5.pdf.

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-21261 shows (and my testimony in that docket discusses) the cost of OVEC is projected to jump significantly going forward.[14]

Table 1. OVEC power costs billed to I&M and market value (2017–2021) ($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)

Source: Direct Testimony of Devi Glick, Pg. 16. Case U-21261.

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 2021 alone, billed energy and capacity charges cost I&M customers $14.2 million more than the market price for the same amount of energy and capacity. This means that ratepayers would have been better off in 2021 if I&M did not purchase power from OVEC and instead purchased energy and capacity from the market.

iii. 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

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

[14] Direct Testimony of Devi Glick, Case U-21261.

to "provide a justification of its costs under the ICPA in its reconciliation of its 2021 PSCR plan"[15] and indicated that it will "look to comparisons with other long-term supply options as informative as to whether this particular contract adheres to the requirements of the Code of Conduct."[16]

In the present docket, I&M proposed to compare the cost of OVEC to the transfer price published by the Commission in Docket U-15800.[17] Company witness Stegall also cited the cost of capacity charged to Consumers Energy under its agreements with the Michigan Power Limited Partnership ("MPLP") and North American Natural Resources ("NANR") Inc.[18] 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 2022. 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 assumptions for new gas resources are generally 30 years, as I&M itself assumed in its most recent integrated resource plan ("IRP").[19]

[15] Commission Order dated November 18, 2021 in Case No. U-20804, Pg. 26.
[16] *Id.*, Pg. 18–19.
[17] Direct Testimony of Company Witness Stegall, Pg. 7.
[18] *Id.*, Pg. 11.
[19] 2021 I&M Integrated Resource Planning Report. January 31, 2022, Pg. 95. Available at https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/2021IMIRPReportRevised.pdf.

Second, the average cost of power over a plant lifetime does nothing to reflect the cost of power in 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.[20]

Q Explain why the 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 two Consumers Energy PPAs that Stegall cited, one for MPLP and one for NANR, are not comparable to the ICPA. Neither are for coal-fired generators, and neither are close to the size of the Clifty Creek or Kyger Creek Plants. The MPLP plant is a 125 MW natural gas plant[21] which, in 2021, was lower cost than OVEC. The NANR plant is a 4.8 MW landfill gas facility.[22]

Witness Stegall first cited these PPAs as comparators in rebuttal testimony in Case No. 20529, where he mischaracterized both units as coal generators. It is forgivable for I&M to erroneously cite these as reasonable comparators in one docket, but cross-examination and briefing in Case No. U-20529 made clear the specific characteristics of each. The Company knows that the Commission is looking to I&M to provide reasonable comparators and that these two PPAs are not reasonable comparators. By citing them again in this current docket, and not providing other reasonable benchmarks, I&M is once again putting the onus on the Commission to determine a reasonable benchmark.

[20] Case No. U-15806 and Case No. U-17302.
[21] Osaka Gas USA, Projects. Available at https://www.osakagasusa.com/projects.
[22] NANR, People's Generation Station. Available at http://www.nanr.net/index#/peoples-generating-station.

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 long-term PPAs; (2) the cost of replacement capacity resources as represented by Cost of New Entry (CONE); (3) The cost of replacement capacity and energy resources as represented by responses to requests for proposals (RFP) and other Company information; (4) and the PJM short-term capacity and energy market. Table 2 below summarizes the alternative benchmarks discussed in this section on a $/MWh basis and calculates the total excess costs incurred under the ICPA relative to each benchmark.

Table 2. OVEC cost benchmarks for 2021 ($2021)

	Capacity cost ($/MWh)	Energy cost ($/MWh)	Total cost ($/MWh)	Excess costs based on benchmark ($Million)
OVEC PSCR cost[1]	$38.25	$25.85	$64.10	NA
Cost of similar services				
MPPA billing from Consumers Energy for Campbell Unit 3[3]	$7.06	$15.30	$22.36	$32.98
MPPA billing from DTE for Belle River[4]	$15.28	$25.01	$40.30	$18.81
Value of CONE & PJM BRA				
CONE – combined cycle plant coming online in 2026[5]	$34.87	$25.85	$60.72	$2.67
CONE – combustion turbine coming online in 2026[5]	$27.99	$25.85	$53.85	$8.10
CONE – combined cycle plant coming online in 2022[6]	$22.63	$25.85	$48.49	$12.34
CONE – combustion turbine coming online in 2022[6]	$20.23	$25.85	$46.08	$14.24
PJM base residual auction (BRA)[7]	$9.16	$25.85	$35.01	$22.98
Replacement resource PPA prices				
I&M renewable RFP results (average)[8]				
Medium solar	$50.00			$11.14
Large solar	$44.00			$15.88
Wind	$45.00			$15.09
NIPSCO RFP Results[9]				
Solar PV	$41.31			$18.01
Solar PV + battery storage	$42.77			$16.85
Wind	$39.63			$19.33

Sources: [1] Ex AG-5, I&M Response to Staff 2-01, Attachment 5; [2] Direct Testimony of Company Witness Stegall, Pg. 12; [3] Ex AG-7, DTE billing statements to MPPA for Belle River Power in 2021; [4] Ex AG-8, Consumers billing statements to MPPA for JH Campbell Unit 3 Power in 2021; [5] Ex AG-9, Brattle PJM CONE Study, 2022, available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx; [6] Ex AG-10 Brattle PJM CONE Study, 2018, available at https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx; [7] Ex AG-11, 2021/2022 BRA Results, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx; [8] Ex AG-12, Indiana Michigan 2021 Integrated Resource Plan, Public Stakeholder Meeting #3A, July 27, 2021; [9] Ex AG-13, 2021 NIPSCO Integrated Resource Plan, Stakeholder Advisory Meeting #3, July 13, 2021.

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

A The cost of power under the ICPA is much higher than the cost paid for power under several similar PPAs in the region. I reviewed Michigan Public Power Agency (MPPA) billing statements from DTE for Belle River[23] and from Consumers for J.H. Campbell 3[24] and calculated the average cost billed for power charged for each unit. I find that in 2021, Consumers Energy billed MPPA an average of $22.36/MWh for power purchased from J.H. Campbell 3 and DTE billed MPPA an average of $40.30 for the power purchased from Belle River. These charges covered the construction, fuel, and operations and maintenance ("O&M") expenses from similar thermal resources and provided both energy and capacity to MPPA.

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. But the Company is not capacity constrained, and it did not show a resource need over the next five years (between 2022–2026).[25] Based on a 2022 report conducted by Brattle for PJM, the PJM value of CONE for a new combined-cycle unit coming online in 2026 is $433/MW-Day, and for a new combustion-turbine unit that value is $348/MW-Day (in $2021).[26] This works out to a total value of $60.72/MWh and $53.85/MWh when OVEC's power is valued based on CONE of a new combined-cycle unit and a new combustion-turbine unit, respectively. The 2018 version of this report estimates the PJM value of CONE as $281/MW-Day for a new combined-

[23] Ex AG-7, DTE billing statements to MPPA for Belle River Power in 2021 obtained under FOIA. Generation from EIA Form 923, adjusted for MMPA's ownership share.

[24] Ex AG-8, Consumers billing statements to MPPA for JH Campbell Unit 3 Power in 2021 obtained under FOIA. from EIA form 923, adjusted for MPPA's ownership share.

[25] Ex AG-14, I&M Exhibit IM-7 in Case No. U-21052.

[26] Ex AG-9, Brattle PJM CONE Study, 2022, available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

cycle unit coming online in 2022 and $251/MW-Day (in $2021) for a new combustion-turbine unit.[27] This works out to a total value of $48.49/MWh and $46.08/MWh when OVEC's power is valued based on CONE of a new combined-cycle unit and combustion-turbine unit, respectively.

I arrived at these values by multiplying the $/MW-Day CONE values by the 174 MW of capacity that I&M purchases as part of the PPA with OVEC and then multiplying that by 365 days in a year. I then added the energy revenues that I&M received for its share of OVEC power. Finally, I divided that total value of the power by the MWh of generation purchased from OVEC to find the total $/MWh.

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 2021/2022 BRA because there remains surplus capacity available for participation in the PJM capacity market. This auction produced a capacity price of $77/MW-day for the first half of 2021 and $140/MW-day for the second half of the year.[28] Capacity prices are expected to continue to drop moving forward, based on downward pressure from three main sources: (1) lower demand, as loads continue to drop below what utilities project, due in large part to increasing levels of energy efficiency investment and adoption of behind-the-meter solar PV;[29] (2) increased supply from the massive quantities of solar and wind (and even gas resources) in the PJM interconnection queue, many of which are coming online in the coming years;[30] (3) relaxation of the Minimum Offer Price Rule (MOPR), which more fully allows for capacity credit of new renewables to show up in the PJM

[27] Ex AG-10, Brattle PJM CONE Study, 2018, available at https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

[28] Ex AG-15, PJM 2021/2022 BRA Results, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx.

[29] Ex AG-16, PJM, 2023/2024 RPM Base Residual Auction Planning Period Parameters. Accessed at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-planning-period-parameters-for-base-residual-auction-pdf.ashx.

[30] Ex AG-17, PJM, Interconnection Process Reform Task Force Update, May 11, 2021. Accessed at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210511/20210511-item-11-interconnection-process-reform-task-force-update.ashx.

capacity auctions as dramatically evidenced in the first two Reliability Pricing Model ("RPM") auction results since the relaxation of the MOPR. The most recent PJM RPM auction cleared more solar PV resources than any previous RPM auction, with more than 8,000 MW of nameplate wind and more than 4,400 MW of nameplate solar PV clearing the market.[31] These factors have combined to reduce PJM prices from inordinately high historical levels down to what we've seen in recent BRA's: the 2022/2023 BRA in April 2021 cleared at $50/MW-Day;[32] the 2023/2024 BRA in June 2022 cleared at $34.13/MW-Day;[33] and the 2024/2025 BRA in February 2023 cleared at $28.92/MW-day.[34] These forces are likely to continue to reduce prices in future PJM auctions as well.

Q How do the prices that I&M received in response to its most recent RFP compare to the costs paid under the ICPA?

A The prices that I&M received in its most recent RFP, issued as part of its 2021 IRP process, are much lower than the costs paid under the ICPA. Specifically, the average bid I&M received for solar PV PPAs was $50/MWh and $44/MWh for medium and large installations, respectively. The average price for a wind PPA was $45/MWh.[35]

Another regional utility, Northern Indiana Public Service Company (NIPSCO), also recently issued an RFP as part of its 2021 IRP process and received bids for solar PV, solar PV paired with battery storage, and wind PPAs, all of which were also far below the cost billed under the ICPA.[36] While current market prices might be higher, NIPSO is currently building out many of the projects it received bids for during the IRP process,

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[31] Ex AG-18, PJM 2023/2024 RPM Base Residual Auction Results, Pg. 6. Accessed at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx#:~:text=Summary%20of%20Results,representing%20a%2021.6%25%20reserve%20margin.

[32] Ex AG-19, PJM 2022/2023 RPM Base Residual Auction Results, Pg.1. Accessed at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx.

[33] Ex AG-18, PJM 2023/2024 RPM Base Residual Auction Results, Pg. 6. Accessed at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx#:~:text=Summary%20of%20Results,representing%20a%2021.6%25%20reserve%20margin.

[34] Ex AG-20, PJM 2024/2025 RPM Base Residual Auction Results, Pg. 5. Accessed at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

[35] Indiana Michigan Power: 2021 Integrated Resource Plan, Public Stakeholder Meeting #3A, July 27, 2021.

[36] Ex AG-13, 2021 NIPSCO Integrated Resource Plan, Stakeholder Advisory Meeting #3, July 13, 2021.

including at least two completed wind projects and several other projects under construction.[37]

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

A The power I&M purchased under the ICPA is extremely high cost by any reasonable measure. I have presented a number of reasonable alternatives in this section, for both current fossil resources contracted under similar PPAs, new fossil resources, and new renewable resource bid prices that demonstrate this point. Yet I&M customers are paying as much as $14.2 million per year in excess of the cost of these long-term supply comparisons.

iv. 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…"[38] 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

[37] NiSource. November 1, 2021. "NIPSCO Advances Its Cost-Saving Electric Generation Transition Plan with Groundbreaking of First Two Solar Projects." Available at: https://www.nisource.com/news/article/nipsco-advances-its-cost-saving-electric-generation-transition-plan-with-groundbreaking-of-first-two-solar-projects-20211101.

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

faith efforts to manage existing contracts such as meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers."[39]

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 Company to modify the ICPA. OVEC also indicated that that it would need Federal Energy Regulatory Commission approval, regulatory approval by state utility commissions, and advance consent from counterparties to OVEC's debt arrangements to modify the contract.[40]

There is no evidence that I&M has followed up on any of those items or made any further efforts beyond sending its initial letter to OVEC to actually renegotiate the ICPA.

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 the many needed to effectuate management or operational decisions because I&M cannot unilaterally force OVEC to do anything."[41]

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 by OVEC. The

[39] Commission Order dated November 18, 2021 in Case U-20804, Pg. 20.
[40] Ex. AG-21, I&M Response to Sierra Club 7-3, Attachment 1. Case U-21052.
[41] Direct Testimony of Witness Stegall, Pg.5.

Commission agreed with this sentiment in its 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."[42]

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 $2.0 million, which is Michigan's jurisdictional share of the total $14.2 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 2021.

4. I&M ALSO PAID EXCESS AND ABOVE-MARKET COSTS TO AEG FOR POWER FROM ROCKPORT IN 2021

i. Overview of Rockport Units 1 and 2

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. The plant is operated by I&M. Unit 1 has a nameplate capacity of 1,320 MW and Unit 2 is 1,300 MW. Unit 1 is 50 percent owned by I&M and 50 percent owned by AEG. As of 2021, Unit 2 was owned by non-affiliated parties and leased back to I&M and AEG at a 50 percent share each. AEG sold 70 percent of its share of each Rockport

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

unit back to I&M and 30 percent to Kentucky Power's ("KPCo") under a unit power sales agreement.[43]

Q How often was Rockport used in 2021?

A The Rockport units operated at only a 21 percent capacity factor in 2021.[44]

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

A I&M is responsible for the costs associated with the 50 percent share of Rockport 1 that it owns and the 50 percent share of Rockport 2 that it leased. The associated fuel costs are planned for in PSCR dockets, passed on directly to customers as fuel costs through fuel clauses, and reconciled in the current docket. The remaining unit costs are passed on to ratepayers through rate cases and other dockets.

I&M also is responsible for the costs associated with the 70 percent share of AEG's portion of Rockport it purchased through the UPA. Because this power is procured through a PPA, instead of from a unit operated by I&M, the entire cost of this share is passed on directly to customers through fuel clauses (not just the fuel costs).

In total, as of 2021, I&M was responsible for 85 percent of the costs associated with Rockport Units 1 and 2.

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[43] Direct Testimony of Hazel Baker, in Case No. U-20529, 2 TR 76. As of December 2022, I&M acquired 100 percent of Rockport Unit 2 and operates the unit as a merchant plant.

[44] EIA Form 923, available at: https://www.eia.gov/electricity/data/eia923/.

ii. I&M paid excessive and above-market costs for power from Rockport to its affiliate AEG in 2021

Q What did I&M's purchases of Rockport power from AEG cost in 2021?

A I&M purchased 1,680,933 MWh of Rockport power from AEG in 2021 for a total cost of $215,685,503. That comes out to $128.31/MWh.[45]

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

A I&M purchased power from Rockport Units 1 and 2 under the UPA with AEG dated March 31, 1982 and an amendment dated May 8, 1989.[46]

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 by counsel that in Case No. U-20530, the Commission held that the UPA is subject to Rule 8(4) of the Code of Conduct.[47]

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.[48] The demand charge includes a return on common equity ("ROE") to AEG.

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

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[45] Ex AG-22, I&M Response to Staff 2-02, Attachment 2; Ex AG-23, I&M Response to AG 1-01, Attachment 2, Audit Request PMA-1 Attachment 6-1.

[46] Ex AG-24, UPA provided as I&M Response to AG Request 1-11 Attachment, Case No. 20804.

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

[48] Ex AG-25, Section 1.3 of the UPA.

A The ROE is set at 12.16 percent.[49]

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.[50] But as part of that order, a settlement agreement was approved that allowed any party to challenge capacity charges associated with Rockport 2 "if circumstances change such that Michigan ratepayers are no longer fairly compensated for the cost of the generating capacity which I&M makes available to the AEP System."[51]

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.

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,[52] 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."[53]

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[49] Ex AG-26, Excerpt of FERC application concerning the UPA, ER19-717-000.
[50] Ex AG-27, I&M Response to AG Request 2-29.
[51] Ex AG-28, Settlement Agreement in Case No. U-9656, Paragraph 10.
[52] Commission Order dated June 7, 2019 in Case U-18404.
[53] *Id*., Pgs. 7-8.

Q Has I&M taken any action in response to the Commission Order in U-18404 with respect to the AEG contract?

A It appears not. When asked in discovery to identify all actions I&M has taken since the Order in U-18404 to seek any changes to the UPA, I&M indicated only that the UPA provides favorable debt and equity financing for AEG's share of the investments made in Rockport.[54]

Q What does I&M mean by "favorable debt and equity financing for AEG's share of the investments made in Rockport"?

A In I&M's most recent IRP case, witness Andrew Williamson testified that AEG's capital structure, which is weighted more heavily to debt than equity and has a lower borrowing rate than I&M's capital structure, provides a lower overall rate of return on the AEG capital-related charges than if I&M's overall rate of return were to be applied to the AEG capital related charges.[55]

Q Do you find that argument persuasive?

A No. It does not represent any actions taken in response to the Commission Order in U-18404. Also, comparing the cost of the UPA with what the hypothetical cost of the UPA would be if AEG had I&M's capital structure is not pertinent to determining whether the UPA charges are above or below market price. This is also not the type of comparison called for by the Commission to evaluate compliance with the affiliate price cap in I&M's recent PSCR cases.

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?

[54] Ex AG-29, I&M Response to AG 1-17.

[55] Rebuttal Testimony of Andrew Williamson in Case No. U-21189.

A No. I&M responded in discovery that it has not made any such comparison.[56] The Company also disagrees that the transfer price comparison it proposes for the ICPA should be applied to the UPA.[57] As I noted earlier, I disagree that the transfer price is a valid comparator to affiliate power purchase arrangements, but if it was a valid comparator for such arrangements there is no reason it should not be applied to the UPA in the same way it would be applied to the ICPA.

Q How does the cost of the Rockport power from the AEG contract compare to market price?

A I&M received an average of $38.56/MWh [58] in energy and ancillary revenues from the market for the Rockport power it purchased from AEG in 2021. I estimate the capacity value of the 917 MW[59] portion of Rockport owned by AEG and purchased by I&M through a PPA based on the PJM market capacity value in 2021 as $21.78/MWh.[60] This adds up to a total market value of $60.35/MWh. But AEG billed I&M $128.31/MWh. This means that I&M customers are paying an estimated $67.97/MWh premium for Rockport's energy and capacity services over the equivalent value of the energy and capacity in the PJM market. This works out to a total $114.2 million premium for Rockport services allocated to I&M based on the UPA. Approximately $15.9 million of this will be passed on to Michigan customers in this reconciliation docket.

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 1 and 2 for each month in 2021.[61] I calculated the energy charges for each month as the sum of fuel, purchased power, other operating revenues, and fuel from the prior month's adjustment for both

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[56] Ex AG-30, I&M Response to AG Request 1-12.
[57] Ex AG-31, I&M Response to AG Request 1-13.
[58] I&M Response to Staff 2-02, Confidential Attachment 1; Ex AG-32, I&M Response to AG 2-48, Confidential Attachment 3.
[59] Direct Testimony of Hazel A. Baker in Case No. U-20529, 2 TR 75.
[60] Ex AG-4, 2022 State of the Market Report for PJM (p.336): https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec5.pdf.
[61] Ex AG-23, I&M Response to AG 1-01, Attachment 2.

units. The remaining charges in the total bill reflect non-variable costs; I classified these as part of a demand charges.

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.

Q Should the Commission compare the cost of Rockport power from the AEG contract to the cost of other long-term supply resources in this reconciliation?

A Yes. While the Commission in U-20530 found that the unique circumstances created by COVID-19 during 2020 did not allow for a proper evaluation of the UPA during that year, those unique circumstances did not persist in 2021. The energy market had recovered by 2021. In 2020, I&M received an average of $21.23/MWh in energy and ancillary revenues from the market for the Rockport power it purchased from AEG,[62] compared to the average of $38.56/MWh it received this year.

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 $15.9 million, which is Michigan's jurisdictional share of the total $114.2 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). 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 2021.

[62] See my direct testimony in Case No. U-20530, p. 34.

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

A As I&M itself stated in discovery, "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."[63] 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 $128.31/MWh for the portion of Rockport owned by I&M.

Q Does this conclude your testimony?

A Yes.

[63] Ex AG-31, I&M Response to AG Request 1-13.

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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

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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.

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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 Utilties 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.

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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.

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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.

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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.

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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 January 2023

Ohio Valley Electric Corporation

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

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

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

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

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

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

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

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

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

Some of the Common Stock issued in the name of:

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

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

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
ATTORNEY GENERAL
DATA REQUEST SET NO. 1
CASE NO. U-20805

DATA REQUEST NO. AG 1-07

Request

Produce, in electronic Excel spreadsheet format, the monthly OVEC Energy Charge, OVEC Energy Revenues, and Net Energy Revenues for each month in 2021 and the total for 2021. Please provide the Michigan share of net revenues as well.

Response

Please see AG 1-07 Attachment 1 for the requested information.

Preparer
Stegall

Table 5-19 Weighted average clearing prices by zone: 2020/2021 through 2023/2024

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2020/2021	2021/2022	2022/2023	2023/2024
RTO				
AEP	$74.42	$133.84	$49.25	$34.13
APS	$74.42	$133.84	$49.25	$34.13
ATSI	$69.75	$142.59	$48.89	$34.13
Cleveland	$68.93	$90.81	$49.41	$34.13
COMED	$182.15	$189.54	$63.70	$34.13
DAY	$72.42	$132.69	$49.16	$34.13
DUKE	$121.24	$127.66	$70.57	$34.13
DUQ	$74.42	$133.84	$49.25	$34.13
DOM	$74.42	$133.84	$49.25	$34.13
EKPC	$74.42	$133.84	$49.25	$34.13
MAAC				
EMAAC				
ACEC	$182.04	$158.72	$96.30	$49.49
DPL	$182.04	$158.72	$96.30	$49.49
DPL South	$178.65	$159.65	$97.41	$69.95
JCPLC	$182.04	$158.72	$96.30	$49.49
PECO	$182.04	$158.72	$96.30	$49.49
PSEG	$165.74	$184.82	$90.67	$49.48
PSEG North	$176.45	$190.48	$89.21	$49.49
REC	$182.04	$158.72	$96.30	$49.49
SWMAAC				
BGE	$80.71	$174.43	$119.73	$69.94
PEPCO	$84.24	$133.37	$94.74	$49.46
WMAAC				
MEC	$81.85	$134.56	$94.49	$49.49
PE	$81.85	$134.56	$94.49	$49.49
PPL	$85.07	$138.51	$95.29	$49.49

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2023/2024[139]

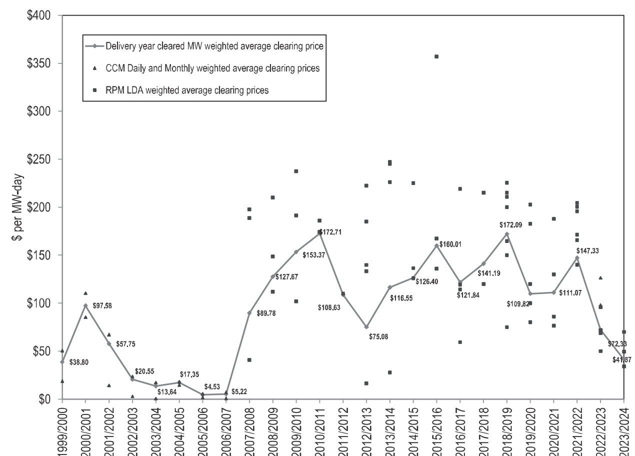
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$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	$41.37	145,066.9	366	$2,196,444,804

139 The results for the ATSI Integration Auctions are not included in this table.

Table 5-21 RPM revenue by calendar year: 2007 through 2024[140]

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	$54.18	147,067.8	365	$2,927,648,376
2024	$41.37	60,246.4	152	$912,184,727

Figure 5-5 History of capacity prices: 1999/2000 through 2023/2024[141]



140 The results for the ATSI Integration Auctions are not included in this table.

141 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2023/2024 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.

Indiana Michigan Power Company
Market Evaluation of the Energy Purchased under the Intercompany Power Agreement

Calendar Year (1)	ICPA MWh (2)	ICPA Energy Cost (3)	ICPA Demand Cost (4)	Total (5) = (3) + (4)	ICPA Cost ($/MWh) (6) = (5) ÷ (2)	In-Year Transfer Price ($/MWh) (7)	ICPA MWh at In-Year Transfer Price (8) = (2) x (7)	ICPA Excess/(Discount) vs. Transfer Price (9) = (8) - (5)	Cumulative ICPA Excess/(Discount) vs. Transfer Price (10) = Σ(9)	Source of Transfer Price (11)
2013	781,964	$23,657,632	$26,981,569	$50,639,200	$64.76	$63.03	$49,287,191	$1,352,010	$1,352,010	2013 MPSC Transfer Price Schedule
2014	853,802	$24,058,551	$23,492,808	$47,551,359	$55.69	$70.12	$59,868,596	($12,317,237)	($10,965,227)	2014 MPSC Transfer Price Schedule
2015	648,744	$18,410,882	$23,335,352	$41,746,234	$64.35	$68.27	$44,289,753	($2,543,519)	($13,508,747)	2015 MPSC Transfer Price Schedule
2016	743,577	$19,962,699	$23,082,805	$43,045,504	$57.89	$71.80	$53,388,829	($10,343,325)	($23,852,072)	2016 MPSC Transfer Price Schedule
2017	937,620	$23,069,742	$25,993,951	$49,063,693	$52.33	$74.95	$70,274,619	($21,210,926)	($45,062,997)	2017 MPSC Transfer Price Schedule
2018	958,430	$22,413,821	$27,485,613	$49,899,434	$52.06	$65.06	$62,355,456	($12,456,021)	($57,519,019)	2018 MPSC Transfer Price Schedule
2019	926,846	$22,674,872	$27,304,697	$49,979,569	$53.92	$62.23	$57,677,627	($7,698,058)	($65,217,077)	2019 MPSC Transfer Price Schedule
2020	721,476	$18,487,826	$28,070,350	$46,558,176	$64.53	$56.27	$40,597,455	$5,960,721	($59,256,355)	2020 MPSC Transfer Price Schedule
2021	790,000	$20,423,658	$30,216,763	$50,640,421	$64.10	$65.65	$51,863,500	($1,223,079)	($60,479,434)	2021 MPSC Transfer Price Schedule

Indiana Michigan Power Company
Comparison of ICPA Cost to 2012 Transfer Price

Calendar Year (1)	ICPA MWh (2)	ICPA Energy Cost (3)	ICPA Demand Cost (4)	Total (5) = (3) + (4)	ICPA Cost ($/MWh) (6) = (5) ÷ (2)	MPSC 2012 Transfer Price ($/MWh)[1] (7)	ICPA MWh at 2012 Transfer Price (8) = (2) x (7)	ICPA Excess/(Discount) vs. Transfer Price (9) = (8) - (5)	Cumulative ICPA Excess/(Discount) vs. Transfer Price (10) = Σ(9)
2013	781,964	$23,657,632	$26,981,569	$50,639,200	$64.76	$62.16	$48,606,882	$2,032,318	$2,032,318
2014	853,802	$24,058,551	$23,492,808	$47,551,359	$55.69	$64.62	$55,172,685	($7,621,326)	($5,589,008)
2015	648,744	$18,410,882	$23,335,352	$41,746,234	$64.35	$67.87	$44,030,255	($2,284,022)	($7,873,029)
2016	743,577	$19,962,699	$23,082,805	$43,045,504	$57.89	$71.16	$52,912,939	($9,867,436)	($17,740,465)
2017	937,620	$23,069,742	$25,993,951	$49,063,693	$52.33	$72.02	$67,527,392	($18,463,699)	($36,204,164)
2018	958,430	$22,413,821	$27,485,613	$49,899,434	$52.06	$71.20	$68,240,216	($18,340,782)	($54,544,946)
2019	926,846	$22,674,872	$27,304,697	$49,979,569	$53.92	$72.09	$66,816,328	($16,836,759)	($71,381,705)
2020	721,476	$18,487,826	$28,070,350	$46,558,176	$64.53	$73.46	$52,999,627	($6,441,451)	($77,823,156)
2021	790,000	$20,423,658	$30,216,763	$50,640,421	$64.10	$74.34	$58,728,600	($8,088,179)	($85,911,335)

[1]The 2012 transfer price was initially presented in MPSC Staff Exhibit S-4 in Case No. U-16662, MPSC Staff Exhibit S-1 in Case No. U-16655, and MPSC Staff Exhibit S-1 in Case No. U-16656.

Source: U-18500

	2012 MPSC Staff Transfer Price Schedule
2013	$62.16
2014	$64.62
2015	$67.87
2016	$71.16
2017	$72.02
2018	$71.20
2019	$72.09
2020	$73.46
2021	$74.34
2022	$75.75
2023	$77.26
2024	$78.81
2025	$80.56
2026	$82.31
2027	$83.69
2028	$84.56
2029	$86.06

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

Indiana Michigan Power Company
OVEC Billing Data
January 2013 to December 2021

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

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

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Jan 2020	73,111	$1,774,282	$2,002,353	$103,859	$31,144	$3,911,638
Feb	64,814	$1,642,742	$1,939,210	$100,820	$33,116	$3,715,888
Mar	53,273	$1,423,887	$2,466,473	$96,633	$26,062	$4,013,055
Apr	30,105	$974,603	$2,635,093	$87,568	$28,325	$3,725,589
May	33,978	$978,732	$2,386,859	$88,915	-$251,480	$3,203,026
Jun	65,730	$1,609,964	$1,938,162	$102,441	$7,588	$3,658,155
Jul	73,949	$1,837,940	$2,150,072	$105,719	$10,518	$4,104,250
Aug	70,557	$1,715,507	$2,197,338	$104,073	-$1,852	$4,015,065
Sep	52,291	$1,396,224	$2,308,890	$96,881	$10,427	$3,812,422
Oct	45,990	$1,224,347	$2,547,592	$94,374	$13,366	$3,879,678
Nov	68,609	$1,712,394	$2,267,110	$103,728	$1,371	$4,084,602
Dec	89,069	$2,197,204	$3,231,200	$111,049	$2,250	$5,541,702
Jan 2021	83,379	$2,039,113	$1,962,282	$108,737	-$262	$4,109,870
Feb	81,771	$2,034,989	$2,427,275	$108,352	$3,543	$4,574,159
Mar	68,592	$1,746,123	$2,446,912	$103,331	-$1,071	$4,295,295
Apr	63,131	$1,612,470	$2,911,163	$103,331	$749	$4,627,713
May	47,249	$1,179,036	$2,627,270	$94,637	-$4,324	$3,896,619
Jun	64,231	$1,680,532	$2,599,049	$101,565	$1,414	$4,382,560
Jul	87,606	$2,233,090	$2,484,140	$110,666	-$1,215	$4,826,681
Aug	87,228	$2,268,838	$2,570,224	$110,707	$1,433	$4,951,202
Sep	77,676	$1,997,082	$2,205,617	$107,122	$7,752	$4,317,574
Oct	38,091	$1,074,755	$2,571,711	$91,581	$30,063	$3,768,111
Nov	36,200	$970,744	$2,549,683	$90,719	$25,795	$3,636,942
Dec	54,846	$1,586,885	$2,861,437	$98,081	$1,749	$4,548,152

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 4
CASE NO. U-20804 (2021 PSCR PLAN)

DATA REQUEST NO. 4-7 SC

Request

Provide the monthly ICAP value for each of the following units over the specific time periods:
a. OVEC historic ICAP for 2015 – 2020
b. OVEC ICAP for PSCR planning period of 2021 – 2025
c. Rockport ICAP for portion of power purchased by I&M from AEG for 2015 – 2020
d. Rockport ICAP for portion of power purchased by I&M from AEG during the PSCR planning period of 2021 – 2025.

Response

a. I&M objects to subpart (a) of this request on the grounds and to the extent the request is overly broad and unduly burdensome and solicits information that is not reasonably calculated to lead to the discovery of admissible evidence. In support of this objection, I&M states subpart (a) of this request seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing. I&M further objects to the extent subpart (a) of this requests seeks information that is outside the PSCR review and forecast period.

b. Please see SC 4-07 Attachment 1.xlsx.

c. I&M objects to subpart (c) of this request on the grounds and to the extent the request is overly broad and unduly burdensome and solicits information that is not reasonably calculated to lead to the discovery admissible evidence. In support of this objection, I&M states subpart (c) of this request seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing I&M. I&M further objects to the extent subpart (c) of this requests seeks information that is outside the PSCR review and forecast period.

d. Please see SC 4-07 Attachment 2.xlsx.

As to objection
Counsel

Preparer
Baker
Stegall

Belle River

The data was saved successfully.

January 2022

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		30,108.88	9,288.60	112,762.55	152,160.03
CHARLEVOI X		13,390.74	4,131.05	50,150.46	67,672.25
CHELSEA		10,874.91	3,354.91	40,728.25	54,958.07
HART		2,028.90	625.92	7,598.55	10,253.37
HOLLAND		127,090.32	39,207.39	475,973.44	642,271.15
LANSING		521,752.05	160,960.58	1,954,044.25	2,636,756.88
LOWELL		10,063.35	3,104.54	37,688.83	50,856.72
PETOSKEY		15,013.86	4,631.78	56,229.30	75,874.94
PORTLAND		4,382.42	1,351.98	16,412.88	22,147.28
TRAVERSE CITY		36,763.68	11,341.60	137,685.80	185,791.08
ZEELAND		40,091.07	12,368.10	150,147.43	202,606.60
TOTAL		**811,560.18**	**250,366.45**	**3,039,421.74**	**4,101,348.37**

Belle River

The data was saved successfully.

February 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		31,242.47	11,926.04	100,236.61	143,405.12
CHARLEVOI X		13,894.90	5,304.03	44,579.63	63,778.56
CHELSEA		11,284.34	4,307.52	36,204.06	51,795.92
HART		2,105.29	803.64	6,754.49	9,663.42
HOLLAND		131,875.22	50,340.11	423,101.18	605,316.51
LANSING		541,395.80	206,664.48	1,736,984.32	2,485,044.60
LOWELL		10,442.23	3,986.06	33,502.26	47,930.55
PETOSKEY		15,579.13	5,946.95	49,983.22	71,509.30
PORTLAND		4,547.42	1,735.87	14,589.70	20,872.99
TRAVERSE CITY		38,147.81	14,561.99	122,391.34	175,101.14
ZEELAND		41,600.49	15,879.96	133,468.70	190,949.15
TOTAL		**842,115.10**	**321,456.65**	**2,701,795.51**	**3,865,367.26**

Belle River

The data was saved successfully.

March 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		22,178.17	10,987.06	106,151.33	139,316.56
CHARLEVOI X		9,863.61	4,886.43	47,210.16	61,960.20
CHELSEA		8,010.45	3,968.37	38,340.37	50,319.19
HART		1,494.49	740.37	7,153.05	9,387.91
HOLLAND		93,614.61	46,376.63	448,067.36	588,058.60
LANSING		384,322.03	190,392.94	1,839,479.62	2,414,194.59
LOWELL		7,412.65	3,672.22	35,479.15	46,564.02
PETOSKEY		11,059.20	5,478.72	52,932.61	69,470.53
PORTLAND		3,228.09	1,599.19	15,450.60	20,277.88
TRAVERSE CITY		27,080.09	13,415.46	129,613.35	170,108.90
ZEELAND		29,531.04	14,629.66	141,344.36	185,505.06
TOTAL		**597,794.43**	**296,147.05**	**2,861,221.96**	**3,755,163.44**

Belle River

The data was saved successfully.

April 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		24,360.79	10,269.01	115,827.91	150,457.71
CHARLEVOI X		10,834.31	4,567.08	51,513.76	66,915.15
CHELSEA		8,798.77	3,709.02	41,835.42	54,343.21
HART		1,641.56	691.98	7,805.12	10,138.66
HOLLAND		102,827.47	43,345.73	488,912.43	635,085.63
LANSING		422,144.23	177,949.99	2,007,163.46	2,607,257.68
LOWELL		8,142.15	3,432.23	38,713.37	50,287.75
PETOSKEY		12,147.56	5,120.66	57,757.85	75,026.07
PORTLAND		3,545.77	1,494.68	16,859.05	21,899.50
TRAVERSE CITY		29,745.11	12,538.71	141,428.69	183,712.51
ZEELAND		32,437.27	13,673.56	154,229.08	200,339.91
TOTAL		**656,624.99**	**276,792.65**	**3,122,046.14**	**4,055,463.78**

Belle River

The data was saved successfully.

May 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		28,200.18	9,157.41	57,673.48	95,031.07
CHARLEVOI X		12,541.86	4,072.70	25,649.93	42,264.49
CHELSEA		10,185.51	3,307.53	20,830.85	34,323.89
HART		1,900.28	617.08	3,886.35	6,403.71
HOLLAND		119,033.65	38,653.66	243,441.17	401,128.48
LANSING		488,676.46	158,687.37	999,414.63	1,646,778.46
LOWELL		9,425.40	3,060.70	19,276.31	31,762.41
PETOSKEY		14,062.09	4,566.37	28,759.01	47,387.47
PORTLAND		4,104.61	1,332.88	8,394.52	13,832.01
TRAVERSE CITY		34,433.11	11,181.42	70,420.72	116,035.25
ZEELAND		37,549.57	12,193.43	76,794.34	126,537.34
TOTAL		**760,112.72**	**246,830.55**	**1,554,541.31**	**2,561,484.58**

Belle River

The data was saved successfully.

June 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		24,410.66	10,462.33	73,531.33	108,404.32
CHARLEVOI X		10,856.49	4,653.06	32,702.61	48,212.16
CHELSEA		8,816.79	3,778.85	26,558.49	39,154.13
HART		1,644.92	705.01	4,954.94	7,304.87
HOLLAND		103,037.98	44,161.74	310,377.52	457,577.24
LANSING		423,008.44	181,300.01	1,274,212.71	1,878,521.16
LOWELL		8,158.82	3,496.84	24,576.51	36,232.17
PETOSKEY		12,172.43	5,217.06	36,666.57	54,056.06
PORTLAND		3,553.03	1,522.82	10,702.67	15,778.52
TRAVERSE CITY		29,806.01	12,774.76	89,783.54	132,364.31
ZEELAND		32,503.68	13,930.97	97,909.64	144,344.29
TOTAL		**657,969.25**	**282,003.45**	**1,981,976.53**	**2,921,949.23**

Belle River

The data was saved successfully.

July 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		21,377.20	9,205.74	95,408.85	125,991.79
CHARLEVOI X		9,507.38	4,094.20	42,432.51	56,034.09
CHELSEA		7,721.14	3,324.99	34,460.34	45,506.47
HART		1,440.51	620.33	6,429.17	8,490.01
HOLLAND		90,233.68	38,857.67	402,723.05	531,814.40
LANSING		370,442.08	159,524.86	1,653,324.71	2,183,291.65
LOWELL		7,144.94	3,076.85	31,888.67	42,110.46
PETOSKEY		10,659.79	4,590.47	47,575.84	62,826.10
PORTLAND		3,111.51	1,339.92	13,887.00	18,338.43
TRAVERSE CITY		26,102.08	11,240.44	116,496.52	153,839.04
ZEELAND		28,464.52	12,257.78	127,040.35	167,762.65
TOTAL		**576,204.83**	**248,133.25**	**2,571,667.01**	**3,396,005.09**

Belle River

The data was saved successfully.

August 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		21,309.12	9,758.09	117,150.35	148,217.56
CHARLEVOI X		9,477.10	4,339.85	52,101.91	65,918.86
CHELSEA		7,696.56	3,524.48	42,313.07	53,534.11
HART		1,435.92	657.55	7,894.23	9,987.70
HOLLAND		89,946.31	41,189.13	494,494.49	625,629.93
LANSING		369,262.32	169,096.38	2,030,079.88	2,568,438.58
LOWELL		7,122.19	3,261.46	39,155.37	49,539.02
PETOSKEY		10,625.84	4,865.89	58,417.29	73,909.02
PORTLAND		3,101.60	1,420.31	17,051.53	21,573.44
TRAVERSE CITY		26,018.95	11,914.86	143,043.42	180,977.23
ZEELAND		28,373.87	12,993.25	155,989.96	197,357.08
TOTAL		**574,369.78**	**263,021.25**	**3,157,691.50**	**3,995,082.53**

Belle River

The data was saved successfully.

September 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		21,013.81	9,675.24	118,107.30	148,796.35
CHARLEVOI X		9,345.76	4,303.00	52,527.51	66,176.27
CHELSEA		7,589.89	3,494.56	42,658.70	53,743.15
HART		1,416.02	651.97	7,958.71	10,026.70
HOLLAND		88,699.79	40,839.41	498,533.79	628,072.99
LANSING		364,144.92	167,660.63	2,046,662.67	2,578,468.22
LOWELL		7,023.48	3,233.77	39,475.22	49,732.47
PETOSKEY		10,478.58	4,824.58	58,894.48	74,197.64
PORTLAND		3,058.61	1,408.26	17,190.82	21,657.69
TRAVERSE CITY		25,658.37	11,813.70	144,211.88	181,683.95
ZEELAND		27,980.65	12,882.93	157,264.17	198,127.75
TOTAL		**566,409.88**	**260,788.05**	**3,183,485.25**	**4,010,683.18**

Belle River

The data was saved successfully.

October 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		27,556.27	8,839.82	62,929.88	99,325.97
CHARLEVOI X		12,255.48	3,931.45	27,987.68	44,174.61
CHELSEA		9,952.94	3,192.82	22,729.39	35,875.15
HART		1,856.89	595.67	4,240.56	6,693.12
HOLLAND		116,315.69	37,313.07	265,628.54	419,257.30
LANSING		477,518.23	153,183.75	1,090,501.84	1,721,203.82
LOWELL		9,210.18	2,954.55	21,033.17	33,197.90
PETOSKEY		13,741.00	4,407.99	31,380.13	49,529.12
PORTLAND		4,010.89	1,286.66	9,159.60	14,457.15
TRAVERSE CITY		33,646.88	10,793.63	76,838.91	121,279.42
ZEELAND		36,692.18	11,770.54	83,793.42	132,256.14
TOTAL		**742,756.63**	**238,269.95**	**1,696,223.12**	**2,677,249.70**

Belle River

The data was saved successfully.

November 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		37,184.12	9,668.33	63,312.05	110,164.50
CHARLEVOI X		16,537.41	4,299.93	28,157.65	48,994.99
CHELSEA		13,430.38	3,492.07	22,867.42	39,789.87
HART		2,505.67	651.50	4,266.31	7,423.48
HOLLAND		156,955.07	40,810.27	267,241.69	465,007.03
LANSING		644,357.70	167,540.99	1,097,124.39	1,909,023.08
LOWELL		12,428.12	3,231.46	21,160.90	36,820.48
PETOSKEY		18,541.95	4,821.14	31,570.70	54,933.79
PORTLAND		5,412.24	1,407.25	9,215.23	16,034.72
TRAVERSE CITY		45,402.71	11,805.27	77,305.54	134,513.52
ZEELAND		49,512.01	12,873.74	84,302.29	146,688.04
TOTAL		**1,002,267.38**	**260,601.95**	**1,706,524.17**	**2,969,393.50**

Belle River

The data was saved successfully.

December 2021

Member	D.S. Plant	DTE O&M	DTE A&G	DTE Fuel	Proj Cost
BAY CITY		25,722.80	8,080.34	136,039.07	169,842.21
CHARLEVOI X		11,440.06	3,593.68	60,502.55	75,536.29
CHELSEA		9,290.71	2,918.51	49,135.40	61,344.62
HART		1,733.34	544.50	9,167.05	11,444.89
HOLLAND		108,576.55	34,107.32	574,224.21	716,908.08
LANSING		445,746.27	140,022.94	2,357,399.41	2,943,168.62
LOWELL		8,597.38	2,700.71	45,468.58	56,766.67
PETOSKEY		12,826.73	4,029.28	67,836.19	84,692.20
PORTLAND		3,744.02	1,176.11	19,800.83	24,720.96
TRAVERSE CITY		31,408.16	9,866.29	166,107.00	207,381.45
ZEELAND		34,250.84	10,759.27	181,140.97	226,151.08
TOTAL		**693,336.86**	**217,798.95**	**3,666,821.26**	**4,577,957.07**

Campbell 3

The data was saved successfully.

January 2022

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY		19,731.69	7,132.76	2,314.34	86,697.32	115,876.11
CHARLEVOIX		7,889.68	2,852.02	925.39	34,665.77	46,332.86
CHELSEA		7,290.85	2,635.55	855.15	32,034.60	42,816.15
HARBOR SPRINGS		1,976.16	714.36	231.79	8,682.89	11,605.20
HART		7,889.68	2,852.02	925.39	34,665.77	46,332.86
HOLLAND		39,448.42	14,260.12	4,626.93	173,328.87	231,664.34
LOWELL		17,755.53	6,418.40	2,082.56	78,014.44	104,270.93
PETOSKEY		5,913.52	2,137.66	693.60	25,982.89	34,727.67
PORTLAND		2,365.41	855.07	277.44	10,393.15	13,891.07
TRAVERSE CITY		39,448.42	14,260.11	4,626.93	173,328.87	231,664.33
TOTAL		**149,709.36**	**54,118.07**	**17,559.52**	**657,794.57**	**879,181.52**

Campbell 3

The data was saved successfully.

February 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	12,534.31	4,671.90	2,277.98	69,141.22	134,933.55
CHARLEVOIX	18,516.23	5,011.82	1,868.05	910.84	27,646.00	53,952.94
CHELSEA	17,110.82	4,631.42	1,726.26	841.71	25,547.63	49,857.84
HARBOR SPRINGS	4,637.84	1,255.33	467.90	228.14	6,924.61	13,513.82
HART	18,516.23	5,011.82	1,868.05	910.84	27,646.00	53,952.94
HOLLAND	92,581.14	25,059.12	9,340.28	4,554.24	138,229.98	269,764.76
LOWELL	41,670.30	11,278.98	4,204.00	2,049.83	62,216.61	121,419.72
PETOSKEY	13,878.39	3,756.49	1,400.15	682.70	20,721.38	40,439.11
PORTLAND	5,551.35	1,502.60	560.06	273.08	8,288.55	16,175.64
TRAVERSE CITY	92,581.14	25,059.11	9,340.26	4,554.22	138,229.98	269,764.71
TOTAL	**351,351.58**	**95,101.00**	**35,446.91**	**17,283.58**	**524,591.96**	**1,023,775.03**

Campbell 3

The data was saved successfully.

March 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	12,813.40	4,654.23	2,242.75	47,316.20	113,334.72
CHARLEVOIX	18,516.23	5,123.42	1,860.99	896.76	18,919.30	45,316.70
CHELSEA	17,110.82	4,734.54	1,719.74	828.69	17,483.30	41,877.09
HARBOR SPRINGS	4,637.84	1,283.28	466.13	224.62	4,738.80	11,350.67
HART	18,516.23	5,123.42	1,860.99	896.76	18,919.30	45,316.70
HOLLAND	92,581.14	25,617.07	9,304.93	4,483.79	94,596.50	226,583.43
LOWELL	41,670.30	11,530.12	4,188.10	2,018.13	42,577.40	101,984.05
PETOSKEY	13,878.39	3,840.13	1,394.86	672.14	14,180.50	33,966.02
PORTLAND	5,551.35	1,536.05	557.94	268.86	5,672.20	13,586.40
TRAVERSE CITY	92,581.14	25,617.08	9,304.93	4,483.80	94,596.50	226,583.45
TOTAL	**351,351.58**	**97,218.51**	**35,312.84**	**17,016.30**	**359,000.00**	**859,899.23**

Campbell 3

The data was saved successfully.

April 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	18,643.33	4,720.15	2,939.05	63,667.89	136,278.56
CHARLEVOIX	18,516.23	7,454.50	1,887.34	1,175.17	25,457.50	54,490.74
CHELSEA	17,110.82	6,888.70	1,744.09	1,085.98	23,525.24	50,354.83
HARBOR SPRINGS	4,637.84	1,867.16	472.73	294.35	6,376.45	13,648.53
HART	18,516.23	7,454.50	1,887.34	1,175.17	25,457.50	54,490.74
HOLLAND	92,581.14	37,272.53	9,436.73	5,875.88	127,287.47	272,453.75
LOWELL	41,670.30	16,776.17	4,247.42	2,644.70	57,291.44	122,630.03
PETOSKEY	13,878.39	5,587.34	1,414.61	880.82	19,081.04	40,842.20
PORTLAND	5,551.35	2,234.94	565.84	352.33	7,632.42	16,336.88
TRAVERSE CITY	92,581.14	37,272.52	9,436.71	5,875.87	127,287.48	272,453.72
TOTAL	**351,351.58**	**141,451.69**	**35,812.96**	**22,299.32**	**483,064.43**	**1,033,979.98**

Campbell 3

The data was saved successfully.

May 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	28,442.03	4,031.80	4,024.63	248.54	83,055.14
CHARLEVOIX	18,516.23	11,372.50	1,612.11	1,609.24	99.38	33,209.46
CHELSEA	17,110.82	10,509.31	1,489.75	1,487.10	91.84	30,688.82
HARBOR SPRINGS	4,637.84	2,848.52	403.79	403.07	24.89	8,318.11
HART	18,516.23	11,372.50	1,612.11	1,609.24	99.38	33,209.46
HOLLAND	92,581.14	56,862.45	8,060.52	8,046.20	496.89	166,047.20
LOWELL	41,670.30	25,593.51	3,628.00	3,621.56	223.65	74,737.02
PETOSKEY	13,878.39	8,523.98	1,208.32	1,206.17	74.49	24,891.35
PORTLAND	5,551.35	3,409.59	483.33	482.47	29.79	9,956.53
TRAVERSE CITY	92,581.14	56,862.48	8,060.53	8,046.21	496.89	166,047.25
TOTAL	**351,351.58**	**215,796.87**	**30,590.26**	**30,535.89**	**1,885.74**	**630,160.34**

Campbell 3

The data was saved successfully.

June 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	25,062.66	2,884.38	(7,499.35)	46,101.50	112,857.33
CHARLEVOIX	18,516.23	10,021.26	1,153.31	(2,998.60)	18,433.61	45,125.81
CHELSEA	17,110.82	9,260.63	1,065.78	(2,771.00)	17,034.47	41,700.70
HARBOR SPRINGS	4,637.84	2,510.07	288.88	(751.08)	4,617.15	11,302.86
HART	18,516.23	10,021.26	1,153.31	(2,998.60)	18,433.61	45,125.81
HOLLAND	92,581.14	50,106.30	5,766.57	(14,993.00)	92,168.03	225,629.04
LOWELL	41,670.30	22,552.59	2,595.51	(6,748.27)	41,484.36	101,554.49
PETOSKEY	13,878.39	7,511.19	864.44	(2,247.53)	13,816.46	33,822.95
PORTLAND	5,551.35	3,004.48	345.78	(899.01)	5,526.58	13,529.18
TRAVERSE CITY	92,581.14	50,106.30	5,766.57	(14,993.00)	92,168.03	225,629.04
TOTAL	**351,351.58**	**190,156.74**	**21,884.53**	**-56,899.44**	**349,783.80**	**856,277.21**

Campbell 3

The data was saved successfully.

July 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	14,484.77	7,362.34	1,821.22	62,177.20	132,153.67
CHARLEVOIX	18,516.23	5,791.71	2,943.82	728.21	24,861.45	52,841.42
CHELSEA	17,110.82	5,352.11	2,720.38	672.94	22,974.43	48,830.68
HARBOR SPRINGS	4,637.84	1,450.67	737.35	182.40	6,227.16	13,235.42
HART	18,516.23	5,791.71	2,943.82	728.21	24,861.45	52,841.42
HOLLAND	92,581.14	28,958.55	14,719.09	3,641.06	124,307.23	264,207.07
LOWELL	41,670.30	13,034.09	6,624.99	1,638.82	55,950.05	118,918.25
PETOSKEY	13,878.39	4,341.03	2,206.47	545.81	18,634.29	39,605.99
PORTLAND	5,551.35	1,736.41	882.59	218.33	7,453.72	15,842.40
TRAVERSE CITY	92,581.14	28,958.56	14,719.08	3,641.08	124,307.21	264,207.07
TOTAL	**351,351.58**	**109,899.61**	**55,859.93**	**13,818.08**	**471,754.19**	**1,002,683.39**

Campbell 3

The data was saved successfully.

August 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	15,008.96	4,214.65	1,890.61	72,936.42	140,358.78
CHARLEVOIX	18,516.23	6,001.31	1,685.22	755.96	29,163.50	56,122.22
CHELSEA	17,110.82	5,545.80	1,557.31	698.58	26,949.95	51,862.46
HARBOR SPRINGS	4,637.84	1,503.17	422.10	189.35	7,304.71	14,057.17
HART	18,516.23	6,001.31	1,685.22	755.96	29,163.50	56,122.22
HOLLAND	92,581.14	30,006.54	8,426.10	3,779.79	145,817.51	280,611.08
LOWELL	41,670.30	13,505.79	3,792.55	1,701.26	65,631.71	126,301.61
PETOSKEY	13,878.39	4,498.13	1,263.12	566.61	21,858.79	42,065.04
PORTLAND	5,551.35	1,799.25	505.25	226.64	8,743.52	16,826.01
TRAVERSE CITY	92,581.14	30,006.53	8,426.10	3,779.79	145,817.51	280,611.07
TOTAL	**351,351.58**	**113,876.79**	**31,977.62**	**14,344.55**	**553,387.12**	**1,064,937.66**

Campbell 3

The data was saved successfully.

September 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	13,414.63	6,408.89	1,710.96	98,233.74	166,076.36
CHARLEVOIX	18,516.23	5,363.82	2,562.58	684.13	39,278.59	66,405.35
CHELSEA	17,110.82	4,956.69	2,368.08	632.20	36,297.29	61,365.08
HARBOR SPRINGS	4,637.84	1,343.50	641.86	171.36	9,838.28	16,632.84
HART	18,516.23	5,363.82	2,562.58	684.13	39,278.59	66,405.35
HOLLAND	92,581.14	26,819.06	12,812.92	3,420.61	196,392.93	332,026.66
LOWELL	41,670.30	12,071.13	5,767.03	1,539.61	88,395.46	149,443.53
PETOSKEY	13,878.39	4,020.32	1,920.72	512.77	29,440.31	49,772.51
PORTLAND	5,551.35	1,608.13	768.29	205.11	11,776.12	19,909.00
TRAVERSE CITY	92,581.14	26,819.08	12,812.91	3,420.63	196,392.94	332,026.70
TOTAL	**351,351.58**	**101,780.18**	**48,625.86**	**12,981.51**	**745,324.25**	**1,260,063.38**

Campbell 3

The data was saved successfully.

October 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	16,195.78	6,916.07	10,043.75	56,553.63	136,017.37
CHARLEVOIX	18,516.23	6,475.85	2,765.38	4,015.98	22,612.87	54,386.31
CHELSEA	17,110.82	5,984.33	2,555.48	3,711.16	20,896.52	50,258.31
HARBOR SPRINGS	4,637.84	1,622.04	692.66	1,005.90	5,663.94	13,622.38
HART	18,516.23	6,475.85	2,765.38	4,015.98	22,612.87	54,386.31
HOLLAND	92,581.14	32,379.27	13,826.90	20,079.88	113,064.35	271,931.54
LOWELL	41,670.30	14,573.74	6,223.42	9,037.85	50,889.69	122,395.00
PETOSKEY	13,878.39	4,853.82	2,072.72	3,010.08	16,948.93	40,763.94
PORTLAND	5,551.35	1,941.53	829.09	1,204.03	6,779.57	16,305.57
TRAVERSE CITY	92,581.14	32,379.27	13,826.90	20,079.86	113,064.36	271,931.53
TOTAL	**351,351.58**	**122,881.48**	**52,474.00**	**76,204.47**	**429,086.73**	**1,031,998.26**

Campbell 3

The data was saved successfully.

November 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	12,296.43	4,622.06	2,816.03	80,739.31	146,781.97
CHARLEVOIX	18,516.23	4,916.71	1,848.12	1,125.99	32,283.47	58,690.52
CHELSEA	17,110.82	4,543.52	1,707.85	1,040.52	29,833.11	54,235.82
HARBOR SPRINGS	4,637.84	1,231.51	462.91	282.03	8,086.18	14,700.47
HART	18,516.23	4,916.71	1,848.12	1,125.99	32,283.47	58,690.52
HOLLAND	92,581.14	24,583.53	9,240.61	5,629.94	161,417.38	293,452.60
LOWELL	41,670.30	11,064.92	4,159.15	2,534.00	72,653.13	132,081.50
PETOSKEY	13,878.39	3,685.20	1,385.22	843.96	24,197.29	43,990.06
PORTLAND	5,551.35	1,474.08	554.09	337.58	9,678.92	17,596.02
TRAVERSE CITY	92,581.14	24,583.54	9,240.61	5,629.93	161,417.36	293,452.58
TOTAL	**351,351.58**	**93,296.15**	**35,068.74**	**21,365.97**	**612,589.62**	**1,113,672.06**

Campbell 3

The data was saved successfully.

December 2021

Member	D.S. Plant	CECo O&M	CECo Fuel Handling	CECo A&G	Fuel Cost	Proj Cost
BAY CITY	46,308.14	14,626.84	4,960.19	1,848.83	75,386.44	143,130.44
CHARLEVOIX	18,516.23	5,848.52	1,983.32	739.25	30,143.14	57,230.46
CHELSEA	17,110.82	5,404.61	1,832.79	683.14	27,855.23	52,886.59
HARBOR SPRINGS	4,637.84	1,464.90	496.77	185.16	7,550.08	14,334.75
HART	18,516.23	5,848.52	1,983.32	739.25	30,143.14	57,230.46
HOLLAND	92,581.14	29,242.58	9,916.63	3,696.26	150,715.68	286,152.29
LOWELL	41,670.30	13,161.94	4,463.42	1,663.66	67,836.36	128,795.68
PETOSKEY	13,878.39	4,383.61	1,486.55	554.09	22,593.05	42,895.69
PORTLAND	5,551.35	1,753.45	594.62	221.63	9,037.22	17,158.27
TRAVERSE CITY	92,581.14	29,242.59	9,916.62	3,696.25	150,715.68	286,152.28
TOTAL	**351,351.58**	**110,977.56**	**37,634.23**	**14,027.52**	**571,976.02**	**1,085,966.91**

PJM CONE 2026/2027 Report

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APRIL 21, 2022

DATE

NOTICE

This report was prepared for PJM Interconnection, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

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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).

Reference Resource

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

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

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

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

Cost Analysis

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

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

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

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

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

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

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

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

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

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

E&AS Methodology

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

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

Implications for Net CONE and VRR Curve

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

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

Heightened Uncertainty. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance.

Finally, we translate the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to achieve its required return on and return of capital. We assume an after-tax weighted-average cost of capital (ATWACC) of 7.5% for a merchant generation investment, which we estimated based on various reference points. An ATWACC of 7.5% is equivalent to a return on equity of 12.8%, a 6.5% cost of debt, and a 65/35 debt-to-equity capital structure with an effective combined state and federal tax rate of 29.25%. For some states with higher state income tax rates of 10%, the ATWACC is 7.4%. We adopt the "level-nominal" approach for calculating the first-year annualized costs of the plants.

Table ES-1 below shows the updated 2022/23 CONE estimates and how the values compare to the CONE parameters used in the upcoming auctions for the 2021/22 delivery year, escalated forward one year to 2022/23. As indicated, costs have decreased sharply by 22–28% for CTs and 40–41% for CCs.

Table ES-1: Updated 2022/2023 CONE Values

	Simple Cycle ($/ICAP MW-year)				Combined Cycle ($/ICAP MW-year)			
	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
2021/22 Auction Parameter	$133,144	$140,953	$133,016	$134,124	$186,807	$193,562	$178,958	$185,418
...Escalated to 2022/23	$136,900	$144,900	$136,700	$137,900	$192,000	$199,000	$184,000	$190,600
Updated 2022/23 CONE	**$106,400**	**$108,400**	**$98,200**	**$103,800**	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Difference from Prior CONE	-22%	-25%	-28%	-25%	-40%	-40%	-40%	-41%

Sources and notes:
All monetary values are presented in nominal dollars.
2021/22 auction parameter values based on Minimum Offer Price Rule (MOPR) Floor Offer Prices for 2021/22 BRA.
PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on S&L analysis of escalation rates for materials, turbine, and labor costs.
CONE includes major maintenance costs in variable O&M costs. Alternative values with major maintenance costs in fixed O&M costs are presented in Appendix C.

The drivers of these decreases are shown in Figure ES-1 and explained below.

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 w as conducted w ithout 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

All-Source Informational RFP Results

INDIANA MICHIGAN POWER
An AEP Company

RFP Responses Summary

Plant Parameters

Plant Parameters	Renewables									Dispatchable				Demand Response
Technology	Medium Solar 20-yr PPA	Medium Solar 30-yr PPA	Large Solar 20-yr PPA	Large Solar 30-yr PPA	Solar + Storage	Wind	Solar	Solar + Storage	Wind	CCGT/CT Capacity	CT Energy	Stand-alone Storage 2-hr	Stand-alone Storage 4-hr	Demand Response
Commercial Structure	PPA	PPA	PPA	PPA	PPA	PPA	BOT	BOT	BOT	PPA	PPA	PPA	PPA	PPA
Capacity Range (MW)	50-200	60	300-600	245-350	10-100	200-300	100-350	100/20-50	200	100-200	256	200	200	5 MW first year (+3MW/yr)
Storage Hours (hrs)	NA	NA	NA	NA	4 hr	NA	NA	4 hr	NA	NA	NA	2-hr	4-hr	NA
Capacity Factor Average (%)	24%	24%	24%	24%	24%	38%	24%	24%	38%	NA	NA	NA	NA	NA
Capacity Factor Min-Max (%)	23%-25%	21%-25%	24%-24%	24%-25%	23%-25%	34%-48%	21%-25%	24%-25%	34%-43%	NA	NA	NA	NA	NA
COD Range	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	Operational	Operational	2023	2023	2022
PPA Term	15-25	30	15-25	30	15-30	12	NA	NA	NA	10	10	15	15	20

All-in Capex/ PPA Price, Nominal$/kW	Medium Solar 20-yr PPA	Medium Solar 30-yr PPA	Large Solar 20-yr PPA	Large Solar 30-yr PPA	Solar + Storage PPA ($/kW-m)	Wind PPA	Solar BOT	Solar + Storage BOT	Wind BOT	CCGT/CT Capacity ($/kW-m)	CT Energy ($/kW-m)	Stand-alone Storage 2-hr	Stand-alone Storage 4-hr	Demand Response (Real 2021$/kW-m)
Min	43	43	33	45	6.5	48	1,245	1,674						
Average	48	43	37	46	7.3	48	1,475	1,914		3.95	1.75	5.98	8.96	3.53
Max	54	43	41	47	8.5	48	1,600	2,310						
Data Points	5	1	2	2	4	1	8	3	0	1	1	1	1	1

Renewable RFP Results

INDIANA MICHIGAN POWER
An AEP Company

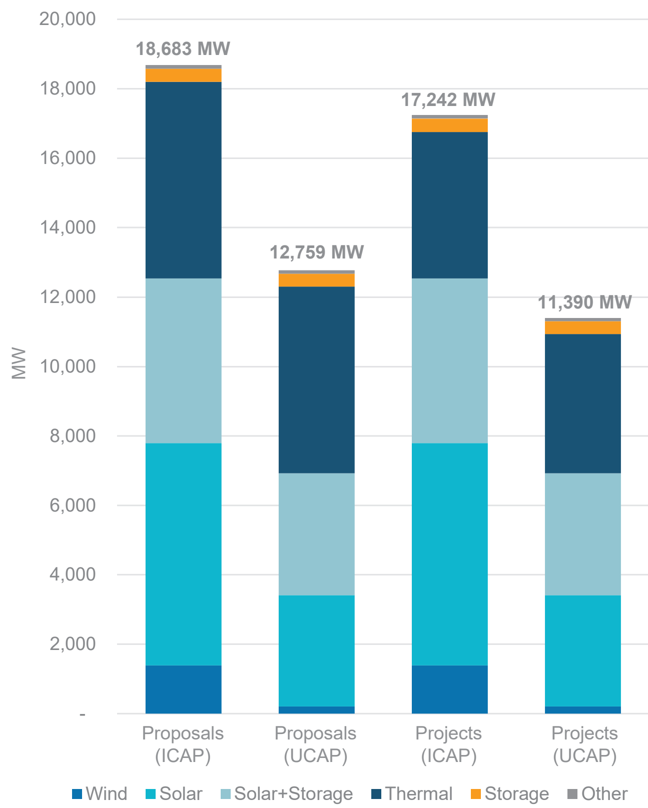
Renewable RFP Responses Summary

Plant Parameters

Plant Parameters	Renewables						
Technology	Medium Solar	Large Solar	Solar + Storage	Wind	Solar	Solar + Storage	Wind
Commercial Structure	PPA	PPA	PPA	PPA	BOT	BOT	BOT
Capacity Range (MW)	85-163	200-353	120-183/ 24-32	200	100-353	100-163/ 20-32	200
Storage Hours (hrs)	NA	NA	4 hr	NA	NA	4 hr	NA
COD Range	2023	2023	2023	2023	2023	2023	2023
PPA Term	30	30	15-30	12-30	NA	NA	NA

All-in Capex/ PPA Price, Nominal$/kW	Medium Solar 30-yr PPA	Large Solar 30-yr PPA	Solar + Storage PPA ($/kW-m)	Wind PPA	Solar BOT	Solar + Storage BOT	Wind BOT
Min	43	41	8.6	45	1,431	1,666	1,953
Average	50	44	8.7	45	1,525	1,781	2,060
Max	59	50	9.0	46	1,592	1,842	2,168
Data Points	10	3	4	2	10	7	2

Proposal and Project Capacity by Technology (MW)



Technology	ICAP by Project		ICAP by Proposal	
	(MW)	%	(MW)	%
Wind	1,391	8%	1,391	7%
Solar	6,404	37%	6,404	34%
Solar + Storage	4,743	28%	4,743	25%
Thermal	4,216	25%	5,657	30%
Storage	388	2%	388	2%
Other	100	1%	100	1%

Technology	UCAP by Project		UCAP by Proposal	
	(MW)	%	(MW)	%
Wind	197	2%	197	2%
Solar	3,202	28%	3,202	25%
Solar + Storage	3,510	31%	3,510	28%
Thermal	4,013	35%	5,382	42%
Storage	368	3%	368	3%
Other	100	1%	100	1%

Note: Unforced capacity ("UCAP") MW are estimated using MISO class averages by technology

Proposal Pricing by Technology & Structure

- UCAP MW were estimated using MISO class averages by technology

Ownership Structures	Capacity (MW "UCAP") of Proposals by Technology								
	Combined Cycle Gas Turbine (CCGT)	Combustion Turbine (CT)	Other Fossil	Wind	Solar	Solar + Storage	Storage	Other	Total
Asset Sale	2,100	489	-	-	50	-	-	-	2,638
Power Purchase Agreement (PPA)	1,082	-	245	62	810	1,323	368	100	3,990
Option	679	787	-	146	2,343	2,187	-	-	6,142
Total	3,861	1,276	245	209	3,202	3,510	368	100	12,770
Locations	IN, MI, IL	IN	IN, MISO	IN, IL, MN	IN, KY, MO	IN, KY	IN	IN	

Note: Totals may not appear to foot due to rounding

Proposal Pricing by Technology & Structure

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Wind	4	976	4	976	$1,494.73	$/kW	
	Solar	25	4,785	25	4,785	$1,299.50	$/kW	
	Solar + Storage	15	3,150	15	3,150	$1,120.51	$/kW	
	Thermal	7	4,268	4	2,827	$876.69	$/kW	Fuel cost additional
Power Purchase Agreement (PPA)	Wind	3	415	3	415	$37.10	$/MWh	Some are not LRZ6
	Solar	23	1,619	23	1,619	$39.30	$/MWh	
	Solar + Storage	8	1,593	8	1,593	$43.30	$/MWh	
	Thermal	7	1,389	7	1,389	$5.44	$/kW-mo	Plus fuel and O&M
	Storage	3	388	3	388	$11.18	$/kW-mo	
	Other	1	100	1	100			
	Total	96	18,683	93	17,242			

Note: Totals may not appear to foot due to rounding

- Average bid prices shown for ‘Asset Sale or Option’ represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport a competition between technologies; Separate short-listed assets were created for each RFP event

NIPSCO CRA Charles River Associates

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on June 2021 Load Forecast
(2022/2023 - 2026/2027)

									Resources								I&M Position (MW)		PJM Reserve Margin			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
				=(1)+(2)				=((3)-((4)*(5)))*(6)			=(8)-(9)						=(13)+(14) - (7)	=(13)+(14) +(15)-(7)	=[(7)+((4)*(5) *(6))]/ (1+(19))		=(17)/(18)	=(19)+(20)
Planning Year		Internal Demand (a)	DSM (b)	Net Internal Demand	Interruptible Demand Response (c)	Demand Response Factor	Forecast Pool Req't (d)	Total UCAP Obligation	ICAP Existing Capacity & Planned Changes(e)	ICAP Net Capacity Transfers (f)	Net ICAP	Incremental Planned Capacity Additions (ICAP) Units	MW	Annual UCAP Purchases	UCAP Existing Capacity (f,g)	UCAP Planned Additions Capacity	Net Position w/o New Capacity	Net Position w/ New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
2022 /23	(h)	3,858	0	3,858	204	1	1.0868	3,972	5,052	(88.8)	5,141				4,868	0	896	896	3,662	14.50%	24.47%	38.97%
2023 /24	(h)	3,881	0	3,881	204	1	1.0863	3,994	5,053	(90.5)	5,143				4,872	0	877	877	3,685	14.40%	23.81%	38.21%
2024 /25	(h)	3,899	0	3,899	204	1	1.0865	4,014	5,048	(90.5)	5,138				4,867	0	853	853	3,703	14.40%	23.03%	37.43%
2025 /26		3,761	(2)	3,759	204	1	1.0865	3,862	5,043	(90.5)	5,133	IRP Solar 120 MW	120		4,862	54	1,000	1,053	3,570	14.40%	29.51%	43.91%
2026 /27		3,764	(5)	3,759	204	1	1.0865	3,863	5,038	(90.5)	5,128	IRP Wind 400 MW, Solar 225 MW	625		4,857	189	994	1,183	3,570	14.40%	33.13%	47.53%

Notes:
(a) Based on June 2021 Load Forecast (with implied PJM diversity factor) plus Ander-Frank load through PY 33/34.
(b) Existing plus approved and projected "Passive" EE, and VVO. DSM is included in the PJM forecast.
(c) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR
(d) Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)
(e) Reflects the members ownership ratio of following summer capability assumptions:
I&M PPR share of OVEC
Wind Farm PPAs (Where Applicable)
EFFICIENCY IMPROVEMENTS:
FGD DERATES:
RETIREMENTS & LEASE END:
Rockport 1 - 12/07/2022 Unit Power agreement with KPCo ends, I&M receives 100% of Unit 1
Rockport 2 - Lease Ends 12/07/2022; I&M receives 100% of Unit 2
(f) Includes IMPA Capacity transfer and Michigan Self Supply.
(g) Based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year
(h) PJM forecast (includes Ander-Frank load)

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

2023/2024 RPM Base Residual Auction Planning Period Parameters

Introduction

The planning parameters for the 2023/2024 RPM Base Residual Auction (BRA) that is to be conducted in June of 2022 were posted on the PJM RPM website on February 28, 2022. This document describes the posted parameters and provides a comparison to the 2022/2023 BRA planning parameters.

PJM RTO Region Reliability Requirement

The PJM RTO forecast peak load, the PJM RTO Region Reliability Requirement and the parameters used to derive the requirement for the 2023/2024 BRA are shown and compared to the 2022/2023 BRA parameters in Table 1.

The forecast peak load for the PJM RTO for the 2023/2024 Delivery Year is 149,680 MW which decreased by 549 MW, or 0.4% compared to the forecast peak load of 150,229 MW for the 2022/2023 BRA. The forecast PJM system peak load is that reported in Table B-10 of the January 2022 RPM update of the PJM Load Forecast Report.[1] The PJM RTO Reliability Requirement for the 2023/2024 Delivery Year is 163,166 MW which decreased by 103 MW, or 0.1% compared to the 2022/2023 BRA value prior to adjustment for FRR obligation of 163,269 MW.[2]

The Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) represent the level of capacity reserves needed to satisfy the PJM reliability criterion of a Loss of Load Expectation not exceeding one occurrence in ten years. The IRM and FPR represent the same level of required reserves but are expressed in different terms of capacity value. The IRM expresses the required reserve level in terms of installed capacity MW (ICAP) as a percent of the forecast peak load, whereas the FPR expresses the required reserve level in terms of unforced capacity MW (UCAP) as a percent of the forecast peak load. The FPR is equal to (1 + IRM) times (1 - Pool-wide Average EFORd). The PJM RTO Reliability Requirement expressed in terms of unforced capacity is used as the basis of the target reserve level to be procured in each RPM BRA and is equal to the forecast RTO peak load, multiplied by the FPR.

[1] The 2022 RPM Forecast is located at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx.
[2] The total UCAP Obligation of all Fixed Resource Requirement (FRR) Entities is subtracted from the PJM RTO Reliability Requirement, and any applicable LDA Reliability Requirement, when determining the target reserve levels to be procured in each RPM BRA.

2023/2024 RPM Base Residual Auction Planning Period Parameters

Table 1 – Reserve Requirement Parameters for 2022/2023 and 2023/2024 BRAs

Reserve Requirement Parameters	2022/2023 BRA	2023/2024 BRA	Change in Value	Change in Percent
Installed Reserve Margin (IRM)	14.50%	14.80%	0.30%	2.1%
Pool Wide 5-Year Average EFORd	5.08%	5.04%	-0.04%	-0.8%
Forecast Pool Requirement (FPR)	1.0868	1.0901	0.0033	0.3%
Forecast Peak Load (MW)	150,229	149,680	-549	-0.4%
PJM RTO Reliability Requirement (UCAP MW)	**163,269**	**163,166**	**-103**	**-0.1%**
FRR Obligation (UCAP MW)*	31,012	31,346	333.5	1.1%
PJM RTO Reliability Requirement adjusted for FRR (UCAP MW)	132,257	131,820	-436.2	-0.3%

Locational Deliverability Areas

Prior to each BRA, the Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) are calculated for each of twenty-seven potential Locational Deliverability Areas (LDAs) that are defined in Schedule 10.1 of the PJM Reliability Assurance Agreement.[3] Pursuant to Section 5.10 of Attachment DD of the PJM Open Access Transmission Tariff (OATT), for any Delivery Year, a separate Variable Resource Requirement (VRR) Curve is established for each LDA for which (1) the CETL is less than 1.15 times its CETO; (2) the LDA had a Locational Price Adder in any one or more of the three immediately preceding BRAs; and (3) the MAAC, EMAAC and SWMAAC LDAs are modeled in a BRA regardless of the outcome of the CETL/CETO test or prior BRA results. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that such 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.

Based on an application of the above criteria, a separate VRR Curve will be established for the 2023/2024 BRA for each of the LDAs listed in Table 2. The list includes the same LDAs that were modeled with a separate VRR Curve in the 2022/2023 BRA. Of the LDAs listed on Table 2, the MAAC, EMAAC, ATSI, BGE, ComEd, DEOK and PS LDAs have cleared with a Locational Price Adder in one or more of the past three BRAs. The DPL SOUTH LDA has a CETL to CETO ratio of 1.14, which is less than 1.15 for the 2023/2024 BRA. While none of the other listed LDAs had a Locational Price Adder in any of the last three BRAs or had a CETL to CETO ratio less than 1.15, they will be modeled in order to maintain an acceptable level of reliability consistent with the Reliability Principles and Standards. Establishing a separate VRR Curve for an LDA does not predestine the LDA to clear the BRA with a Locational Price

[3] CETO and CETL values were calculated for each of the twenty-seven potential LDAs defined in Schedule 10.1 of the PJM RAA and these values are shown on the detailed planning parameters spreadsheet posted on the PJM RPM website.

Adder; an LDA will only clear at a higher clearing price if reliability constraints are reached when attempting to import capacity into the LDA in the auction clearing.

A Reliability Requirement and a separate Variable Resource Requirement (VRR) Curve are established for each LDA that is modeled in the BRA and the LDA CETL acts as a maximum limit on the quantity of capacity that can be imported into the LDA. Table 2 shows the Reliability Requirement and the CETL for each LDA being modeled in the 2023/2024 BRA. For comparison purposes, the LDA Reliability Requirement and CETL values used in the 2022/2023 BRA are also shown in Table 2.

Changes in LDA reliability requirement are primarily driven by changes in the forecast peak load of the LDA and changes in the availability rate of capacity resources located in the LDA. The reliability requirement of an LDA will decrease for a decrease in the forecast peak load of the LDA and an increase in the availability rate of capacity resources located in the LDA. The reliability requirement of an LDA will increase for an increase in the forecast peak load of the LDA and a decrease in the availability rate of capacity resources located in the LDA.

Year-over-year changes in the CETL of an LDA are primarily driven by the addition or removal of transmission facilities, the magnitude and location of generation deactivations and generation additions, and changes in load distribution profile within the LDA. LDA CETL values for the 2023/2024 BRA vary significantly in some cases from those of the 2022/2023 BRA in both the upward and downward direction but, in general, the magnitude of the changes for most regions lies within the year-to-year changes historically experienced.

Of those LDAs that had a Locational Price Adder in one or more of the last three BRAs, the MAAC LDA CETL had the largest increase as compared to 2022/2023 and the COMED LDA CETL had the largest decrease as compared to 2022/2023. The MAAC LDA CETL is 2,006 MW higher for the 2023/2024 BRA, a 46% increase from the 2022/2023 BRA CETL. The COMED LDA CETL is 1,058 MW lower for the 2023/2024 BRA, a 15% decrease from the 2022/2023 BRA CETL.

The increase in MAAC LDA CETL is primarily attributable to the deactivation of the Morgantown generating units for which deactivation notifications were submitted in June of 2021 with a requested deactivation date of May 2022. The removal of nearly 1,230 MW of Morgantown generation from the CETL model reduced the loading on the High Ridge-Sandy Spring 230 kV line which was a limiting transmission facility in the 2022/2023 BRA CETL model. The reduced loading of this circuit allowed for a higher level of imports into the MAAC LDA before this same circuit again limited the LDA CETL in the 2023/2024 CETL model.

The decrease in COMED LDA CETL is primarily attributable to the deactivation of the Waukegan, and Will County generating units for which deactivation notifications were submitted in June of 2021 with requested deactivation dates of May 2022 for the Waukegan and Will County units. The removal of these generation resources totaling about 1,300 MW from the CETL model resulted in a significantly different flow pattern and different set of transmission facilities that limited imports into the ComEd LDA at a lower CETL level than that of the 2022/2023 BRA CETL.

Table 2 – LDA Reliability Requirements and Capacity Import Limits for 2022/2023 and 2023/2024 BRAs

	2022/2023 BRA		2023/2024 BRA		Delta			
LDA	Reliability Requirement (UCAP MW)	CETL (MW)	Reliability Requirement (UCAP MW)	CETL (MW)	Reliability Requirement (UCAP MW)	CETL (MW)	Reliability Requirement (Percent)	CETL (Percent)
MAAC	64,514.0	4,375.0	63,819.0	6,381.0	-695.0	2,006.0	-1%	46%
EMAAC	35,884.0	9,173.0	35,590.0	8,704.0	-294.0	-469.0	-1%	-5%
SWMAAC	14,934.0	8,310.0	14,329.0	8,389.0	-605.0	79.0	-4%	1%
PS	11,686.0	8,626.0	11,217.0	9,022.0	-469.0	396.0	-4%	5%
PS NORTH	6,180.0	4,360.0	5,768.0	4,349.0	-412.0	-11.0	-7%	0%
DPL SOUTH	3,155.0	2,053.0	3,141.0	2,008.0	-14.0	-45.0	0%	-2%
PEPCO	7,701.0	6,781.0	7,163.0	7,160.0	-538.0	379.0	-7%	6%
ATSI	15,011.0	9,119.0	14,649.0	10,213.0	-362.0	1,094.0	-2%	12%
ATSI-Cleveland	5,761.0	5,229.0	5,363.0	4,728.0	-398.0	-501.0	-7%	-10%
COMED	23,931.0	6,839.0	24,077.0	5,781.0	146.0	-1,058.0	1%	-15%
BGE	7,828.0	5,683.0	7,522.0	5,615.0	-306.0	-68.0	-4%	-1%
PL	10,244.0	4,850.0	10,251.0	4,916.0	7.0	66.0	0%	1%
DAYTON	3,950.0	3,941.0	3,924.0	4,022.0	-26.0	81.0	-1%	2%
DEOK	7,407.0	5,465.0	6,847.0	5,632.0	-560.0	167.0	-8%	3%

Variable Resource Requirement Curves

A Variable Resource Requirement (VRR) curve is established for the RTO and for each LDA modeled in the BRA. The VRR curve is a downward-sloping demand curve used in the clearing of the BRA that defines the price for a given level of capacity resource commitment relative to the applicable reliability requirement. The VRR curves for the PJM Region and each LDA are based on a target level of capacity and the Net Cost of New Entry (Net CONE). As shown on the posted planning parameters and as discussed in the Price Responsive Demand (PRD) section of this report, the VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis to reflect any PRD that has elected to participate in the 2023/2024 Delivery Year BRA.

2023/2024 RPM Base Residual Auction Planning Period Parameters

Target Level of Capacity
In the development of the VRR curve, the target level of capacity to be procured for the PJM RTO Region is the PJM RTO Region Reliability Requirement, and the target level of capacity for each LDA is the LDA Reliability Requirement.

Net Cost of New Entry (CONE)
The Net CONE (in UCAP terms) is used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA. Table 3 shows the Net CONE values, and the components used to determine the Net CONE, for the PJM RTO and each LDA to be modeled in the 2023/2024 BRA. For comparison purposes, the CONE values used in the 2022/2023 BRA are also shown in Table 3.

The Net CONE for the RTO and each LDA is equal to the gross CONE applicable to the RTO and each LDA minus the applicable net energy and ancillary services ("EAS") revenue offset. The Net CONE increased for the RTO and for all of the modeled LDAs. The Net CONE of the RTO increased by 5.6% and the increase in LDA Net CONE values ranged from -3.1% for the BGE LDA to 15.0% for the COMED LDA. The increase in Net CONE across most LDAs is due to the escalation in Gross CONE values determined as part of the quadrennial review update and the historic EAS values increasing slightly or decreasing for some LDAs. The Gross CONE values increased in all LDAs, while the calculated Historic Net EAS decreased in all LDAs except for the RTO, SWMAAC, PEPCO, and BGE LDAs. The Net EAS values for the 2023/2024 Delivery Year are calculated using historic LMP data from calendar years 2019 through 2021, whereas the Net EAS values for the 2022/2023 Delivery Year were calculated using the LMPs and fuel prices from calendar years 2018 through 2020.

2023/2024 RPM Base Residual Auction Planning Period Parameters

Table 3 – Net CONE for PJM RTO and LDAs for 2022/2023 and 2023/2024 BRAs

	2022/2023 BRA				2023/2024 BRA				Change in Net CONE	
Location	Gross CONE ICAP Terms ($/MW-Year)	E&AS Offset ICAP Terms ($/MW-Year)	Net CONE ICAP Terms ($/MW-Year)	Net CONE UCAP Terms ($/MW-Day)	Gross CONE ICAP Terms ($/MW-Year)	E&AS Offset ICAP Terms ($/MW-Year)	Net CONE ICAP Terms ($/MW-Year)	Net CONE UCAP Terms ($/MW-Day)	Net CONE UCAP Terms ($/MW-Day)	Net CONE UCAP Terms (%)
RTO	$107,175	$16,924	$90,251	$260.50	$113,862	$18,300	$95,562	$274.96	$14.46	5.6%
MAAC	$107,627	$22,703	$84,925	$245.12	$114,590	$18,987	$95,603	$275.08	$29.96	12.2%
EMAAC	$108,000	$18,144	$89,856	$259.36	$115,311	$14,050	$101,261	$291.36	$32.00	12.3%
SWMAAC	$109,700	$25,530	$84,173	$242.95	$116,593	$31,540	$85,054	$244.72	$1.77	0.7%
PS, PS NORTH	$108,000	$14,997	$93,003	$268.44	$115,311	$11,182	$104,130	$299.61	$31.17	11.6%
DPL SOUTH	$108,000	$26,173	$81,827	$236.18	$115,311	$23,242	$92,070	$264.91	$28.73	12.2%
PEPCO	$109,700	$19,786	$89,914	$259.52	$116,593	$22,755	$93,839	$270.00	$10.48	4.0%
ATSI, Cleveland	$105,500	$25,642	$79,858	$230.50	$111,731	$20,299	$91,432	$263.07	$32.57	14.1%
COMED	$105,500	$19,626	$85,874	$247.86	$111,731	$12,690	$99,041	$284.97	$37.11	15.0%
BGE	$109,700	$31,273	$78,427	$226.37	$116,593	$40,325	$76,269	$219.44	-$6.93	-3.1%
PL	$105,500	$18,744	$86,756	$250.41	$111,814	$14,666	$97,147	$279.52	$29.11	11.6%
DAYTON	$105,500	$27,090	$78,410	$226.32	$111,731	$25,910	$85,821	$246.93	$20.61	9.1%
DEOK	$105,500	$28,023	$77,477	$223.63	$111,731	$23,928	$87,803	$252.63	$29.00	13.0%

Price Responsive Demand (PRD)

Price Responsive Demand is provided by a PJM Member that represents retail customers having the ability to automatically 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.

In order to commit PRD for a Delivery Year, a PRD Provider must submit a PRD Plan by August 6th preceding the BRA for such Delivery Year that demonstrates to PJM's satisfaction that the nominated amount of PRD will be available by the start of the Delivery Year and that the Plan satisfies all requirements as described in section 3A of PJM Manual18: PJM Capacity Market.[4] A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. Once committed in a BRA, a PRD

[4] PRD Providers must submit a PRD Plan by January 15th preceding the BRA for such Delivery Year during normal BRA scheduled auctions.

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.

As shown in the 2023/2024 Planning Parameters, 235 MW of PRD across the RTO has elected to participate in the 2022/2023 BRA: 87 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 38 MW in the EMAAC LDA (with 15.4 MW located in the DPL-South LDA). By comparison, 230 MW of PRD elected to participate in the 2022/2023 BRA: 80 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 40 MW in the EMAAC LDA (with 19.6 MW located in the DPL-South LDA).

Summary

- The forecast peak load for the PJM RTO for the 2023/2024 Delivery Year is 149,680 MW which is 547 MW, or 0.4%, below the forecast peak load of 150,229 MW for the 2022/2023 BRA.
- The PJM RTO Reliability Requirement for the 2023/2024 Delivery Year is 163,166 MW which is 103 MW, or 0.1%, below the 2022/2023 BRA value prior to adjustment for FRR obligation.
- The MAAC, EMAAC, SWMAAC, PS, PSNORTH, PEPCO, DPLSOUTH, ATSI, Cleveland, ComEd, BGE, PPL, DAYTON, and DEOK LDAs will be modeled in the 2023/2024 BRA. These are the same LDAs that were modeled in the 2022/2023 BRA.
- 235 MW of PRD across the RTO has elected to participate in the 2023/2024 BRA: 87 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 38 MW in the EMAAC LDA (with 15.4 MW located in the DPL-South LDA).
- The Reliability Requirement of the RTO and each LDA will be increased by the total UCAP value of all EE Resources that clear in the auction in order to avoid double counting of cleared EE Resource MW since energy efficiency measures are already reflected in the peak load forecast.

Interconnection Process Reform Task Force Update

Jason Connell
Infrastructure Planning
Planning Committee
May 11, 2021

Task Force Update

- First meeting was April 23
  - Education – existing interconnection process summary
  - Review the work plan
    - Targeting completion by year end
  - Interest identification
    - Study Process
    - Cost Concerns
    - Interim Operation/Agreements
    - Application requirements

Backlog Update

- PJM is reprioritizing its interconnection queue work
  - AG1 System Impact Studies will remain on schedule for August
  - AG2 Feasibility Studies will be postponed until at least January 2022
  - Staff will shift focus to backlogged studies
  - Staff augmentation over the next six months
- Next IPRTF meeting is June 1, 2021

PJM Interconnection Queue Status Update

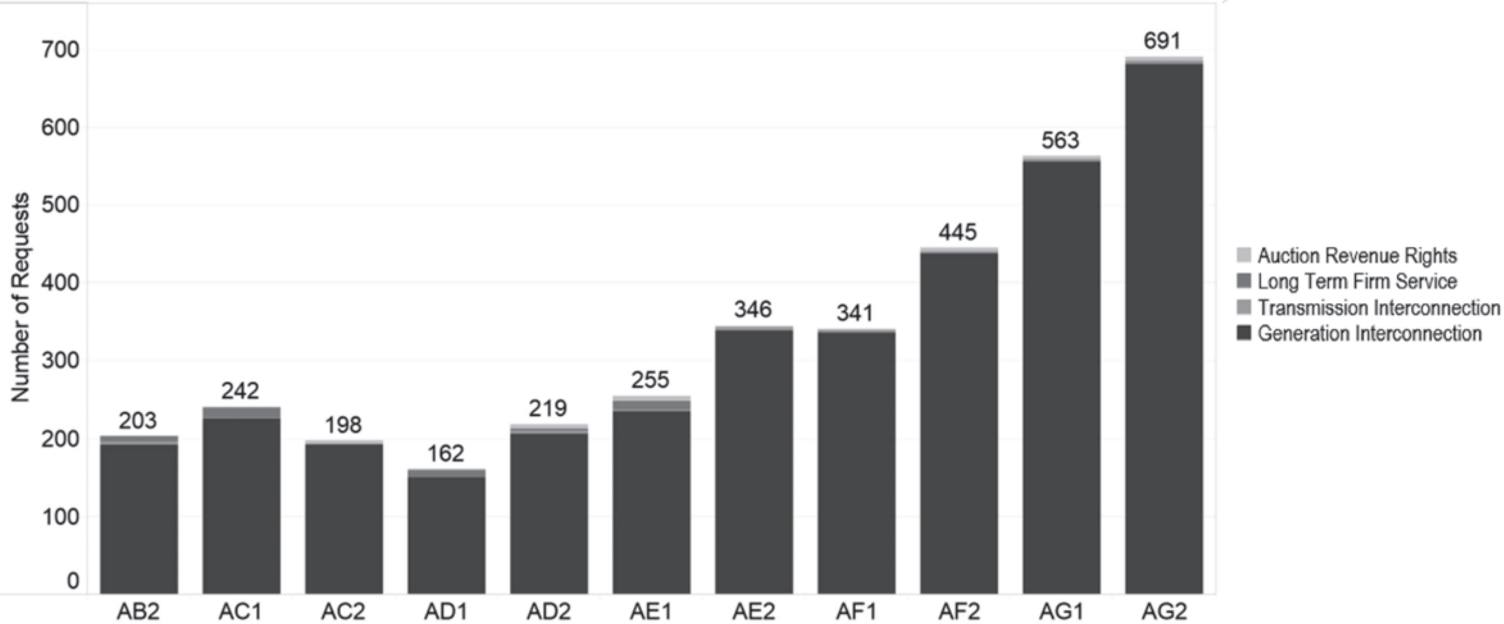
Onyinye Caven
Interconnection Projects
Planning Committee
May 11, 2021

Overview

- Queue Trends: AB2 (November 2015) – AG2 (March 2021)
- AG2 Queue Overview

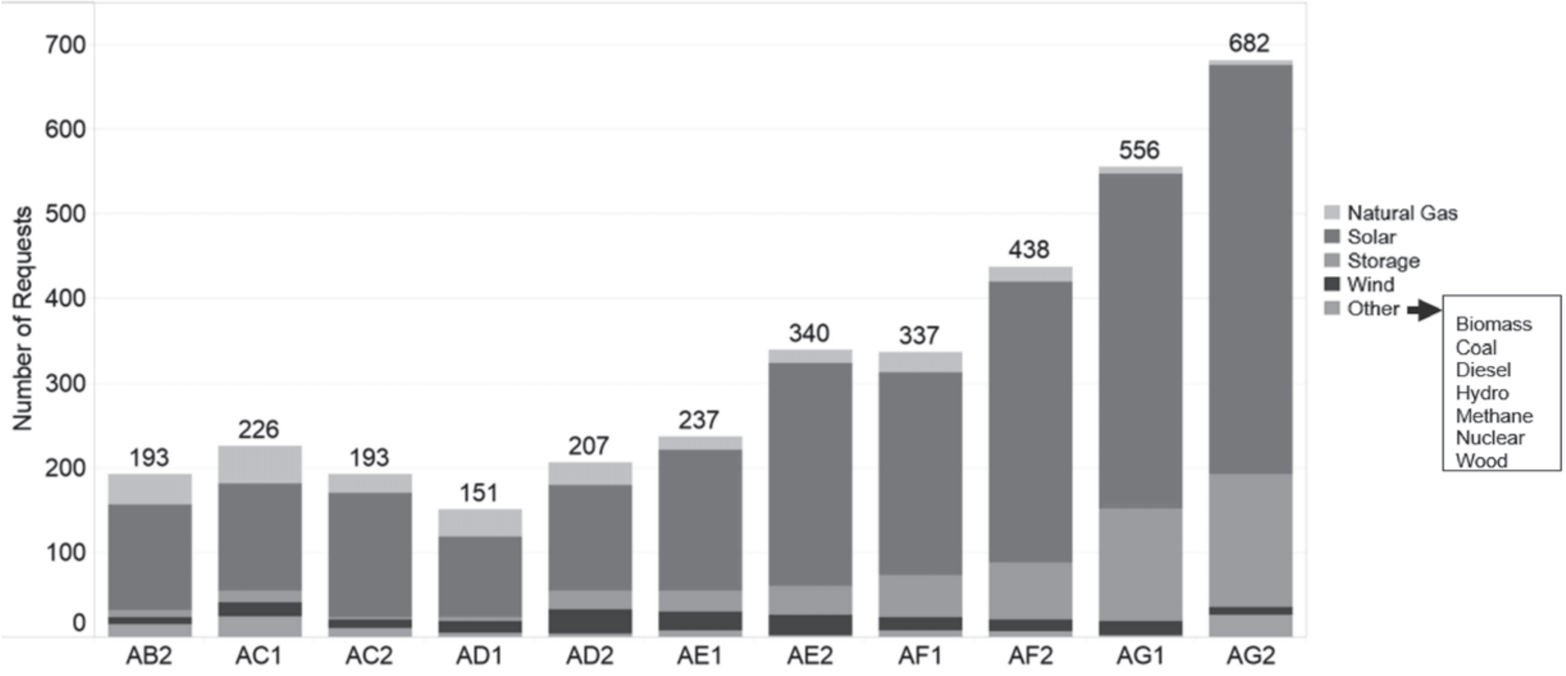
Note: Data provided is a snapshot of the Interconnection Queue as of April 30, 2021

Recent Queue Trends: AB2 – AG2
Total New Service Requests by Application Type



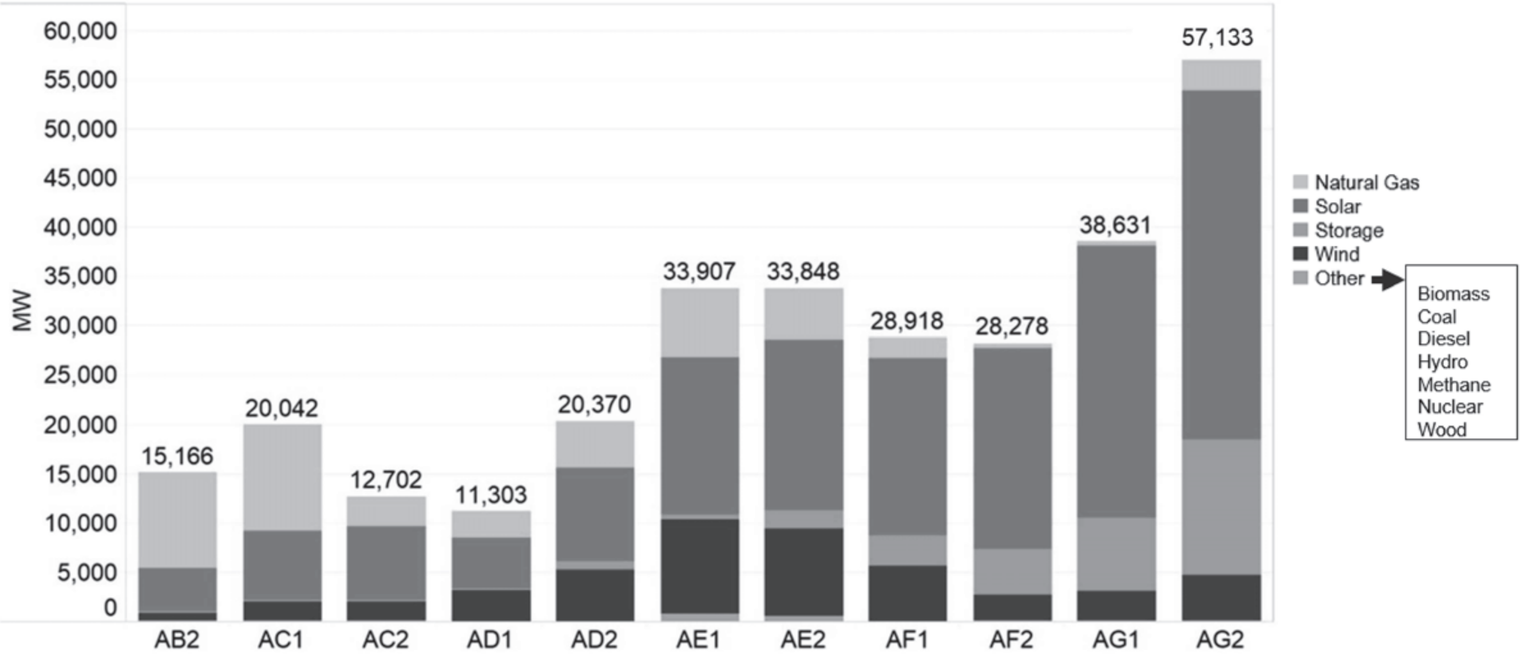
Recent Queue Trends: AB2 –AG2

Generation Interconnection Requests – Total Number



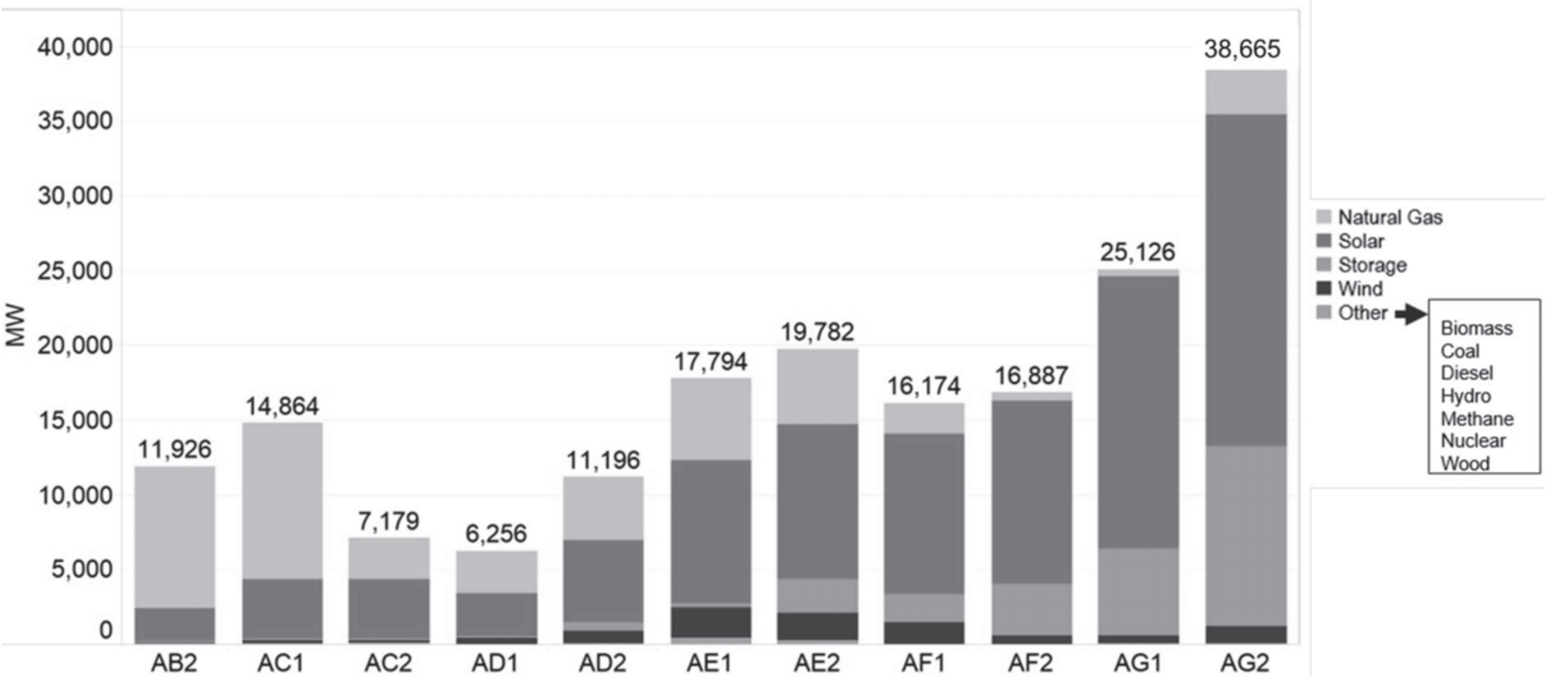
Recent Queue Trends: AB2 – AG2

Generation Interconnection Requests – Requested Energy



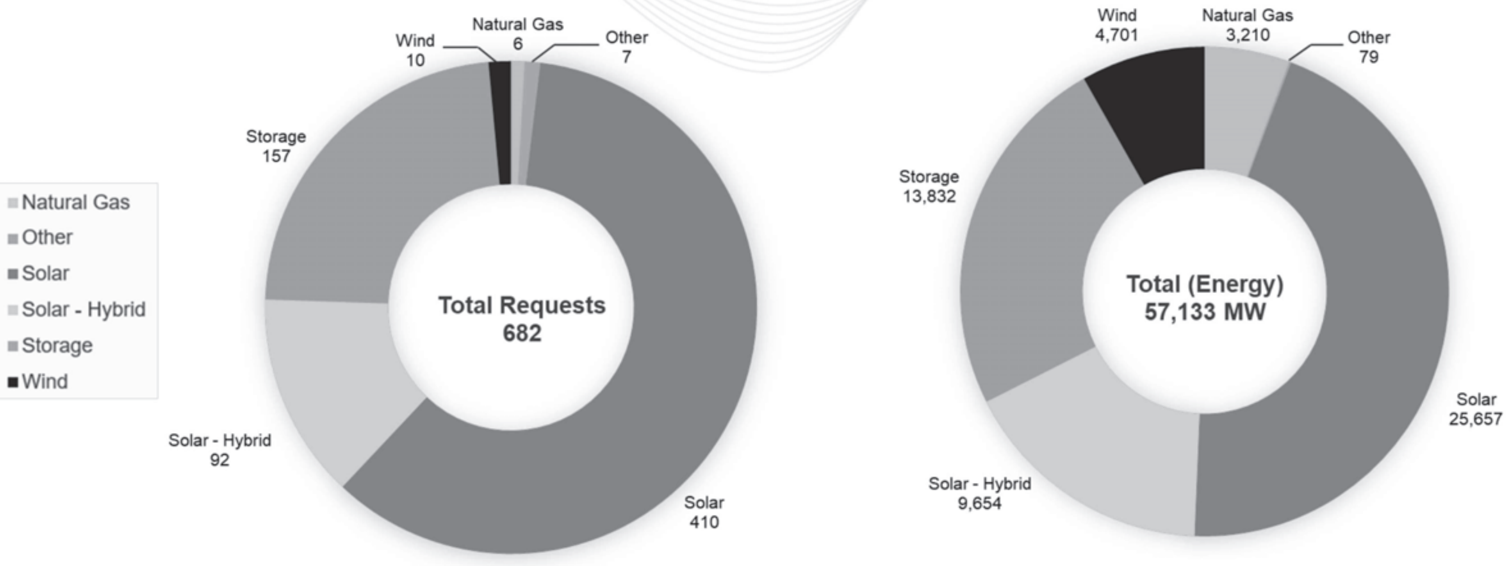
Recent Queue Trends: AB2 – AG2

Generation Interconnection Requests – Requested CIRs

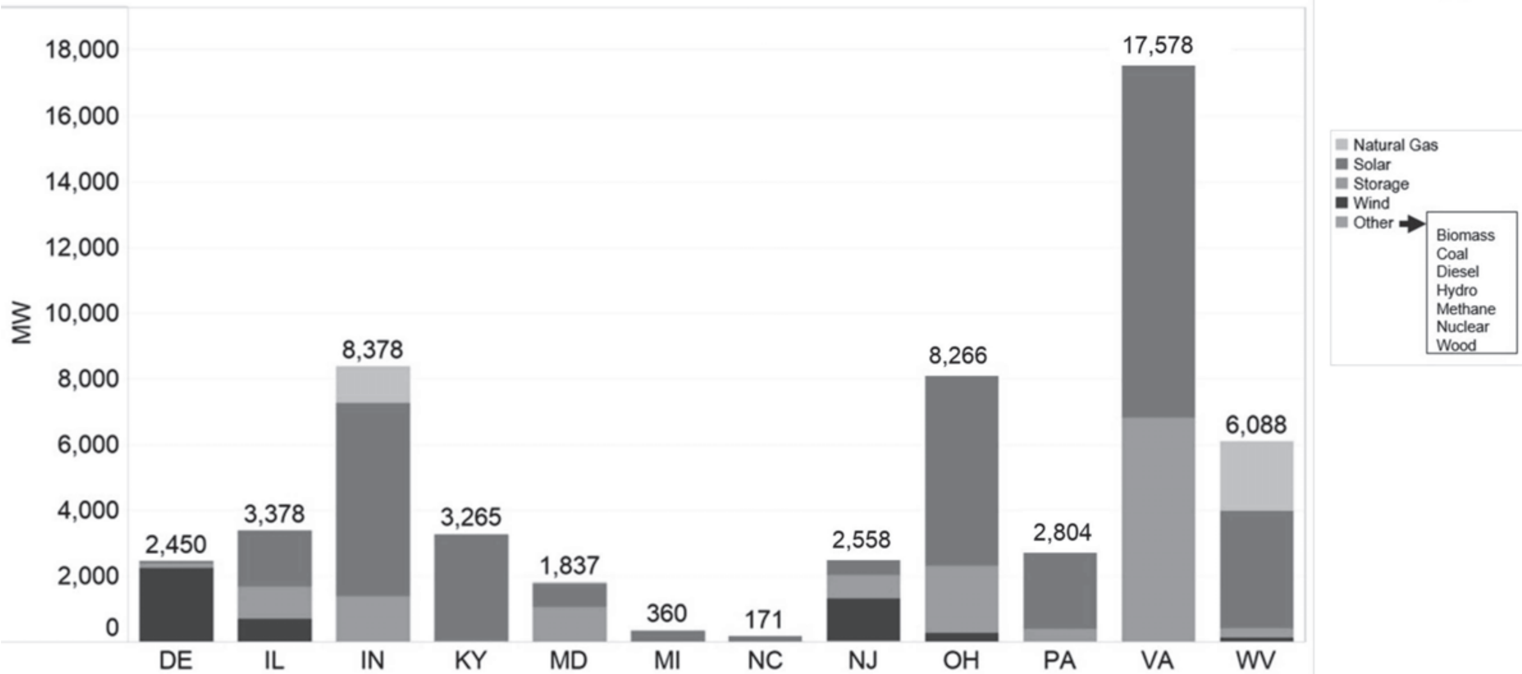


AG2 Queue Overview
(Generation Interconnection Requests)

AG2 Queue Overview
Generation Interconnection Requests by Fuel Type

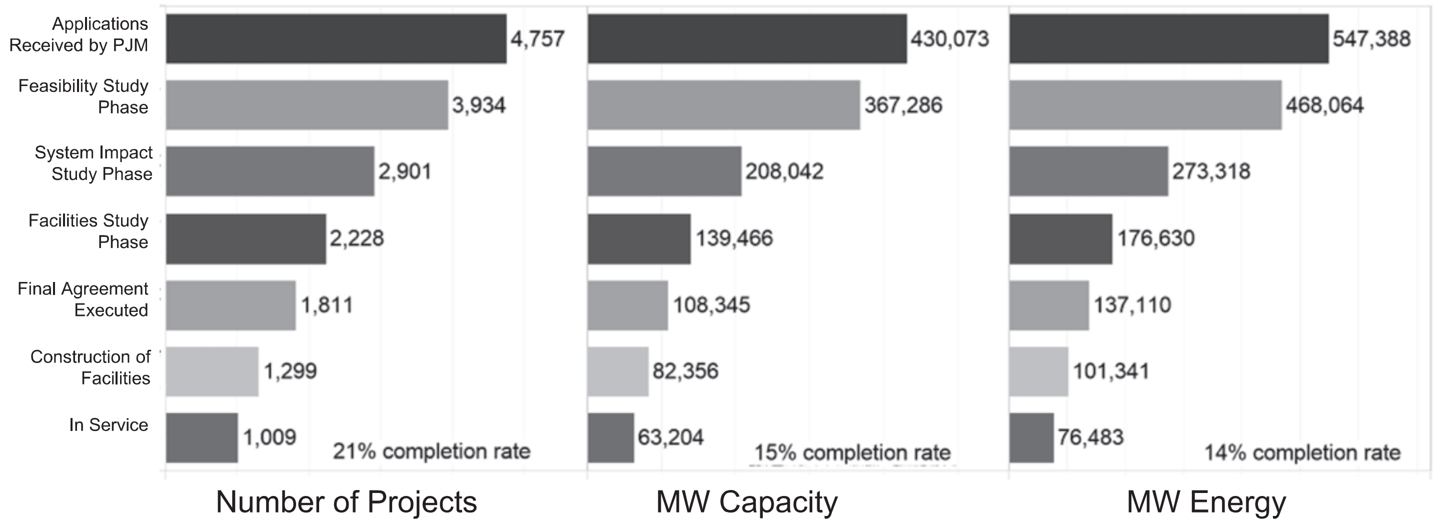


AG2 Queue Overview
All Fuel Types by State - Requested Energy

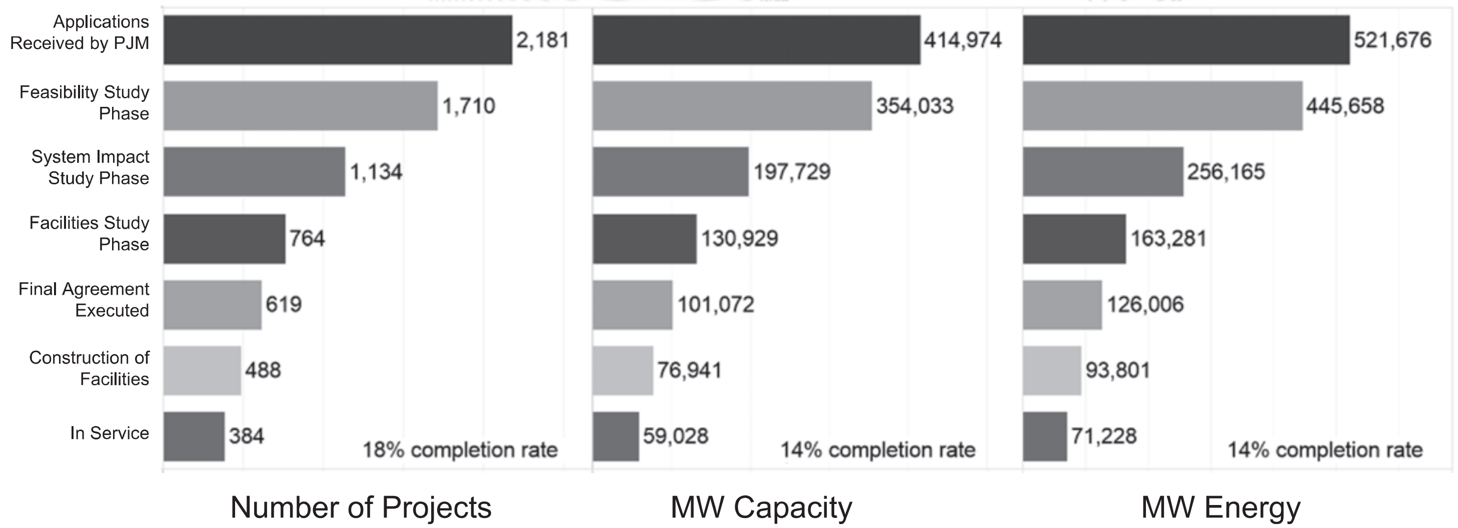


A – AG2 Queue and Active Queue Projects

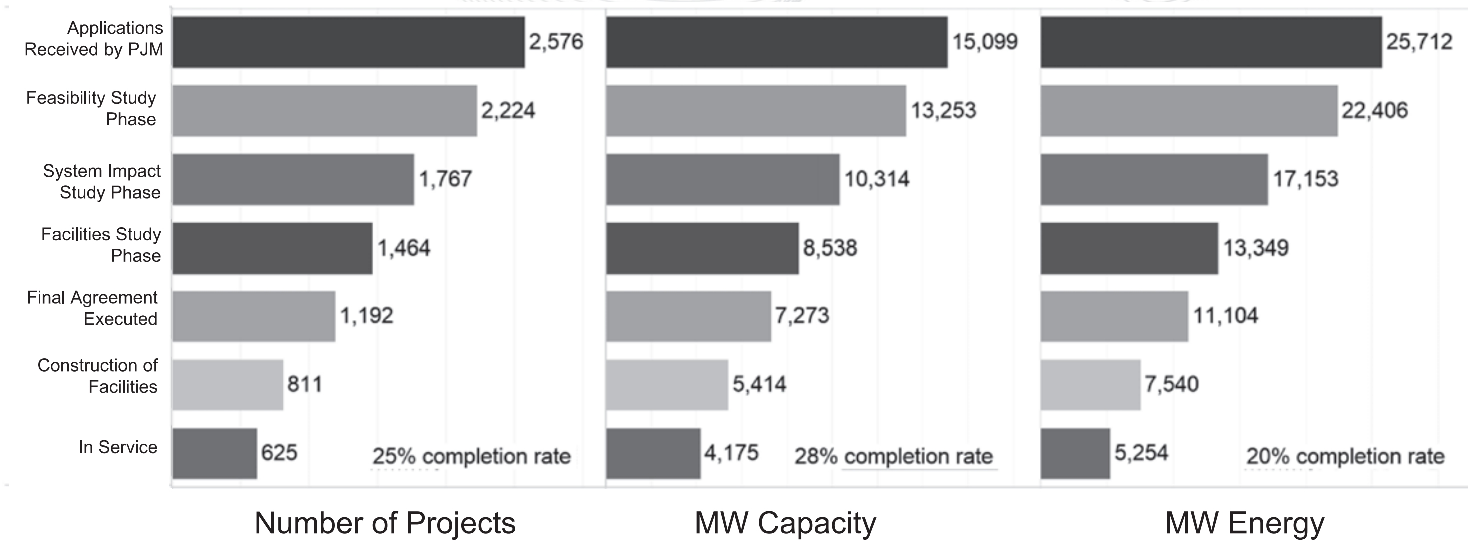
Generation Phase Progression: A – AG2
All Generation Requests



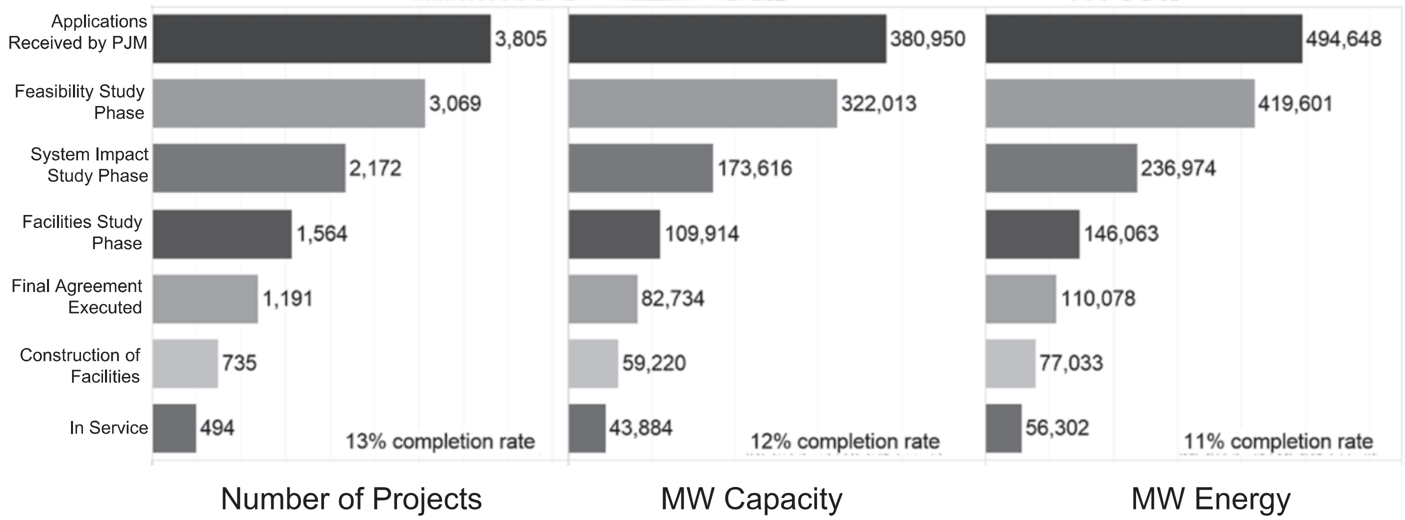
Generation Phase Progression: A – AG2
Large Generation Requests (> 20 MW)



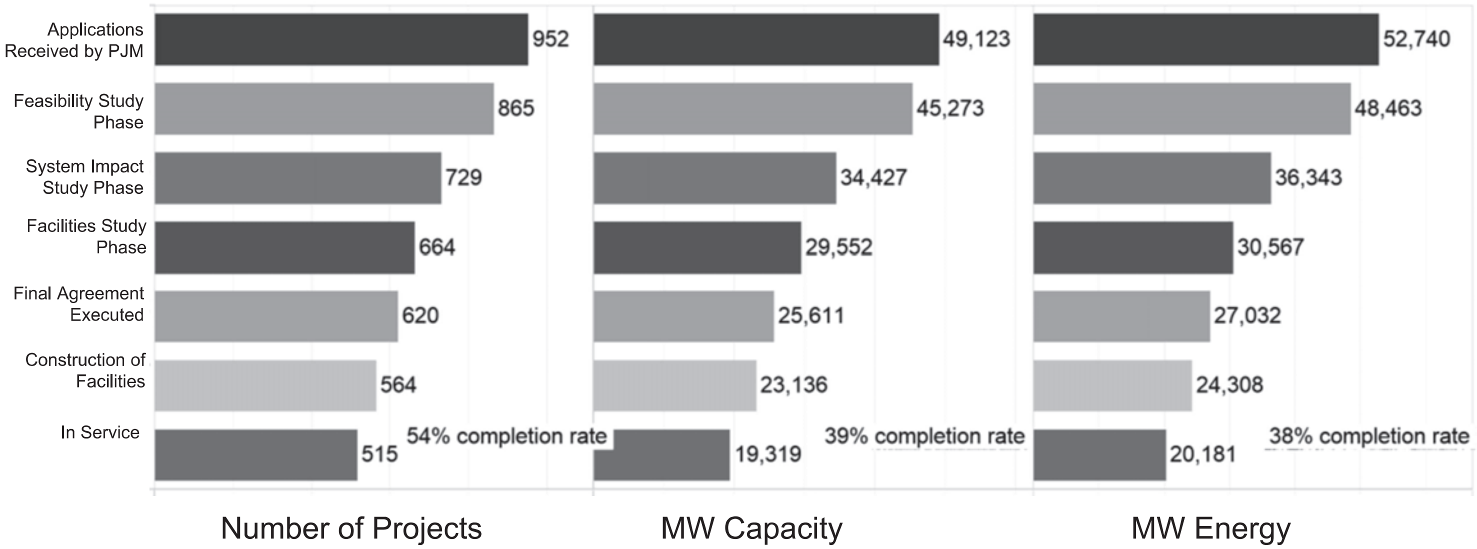
Generation Phase Progression: A – AG2
Small Generation Requests (≤ 20 MW)



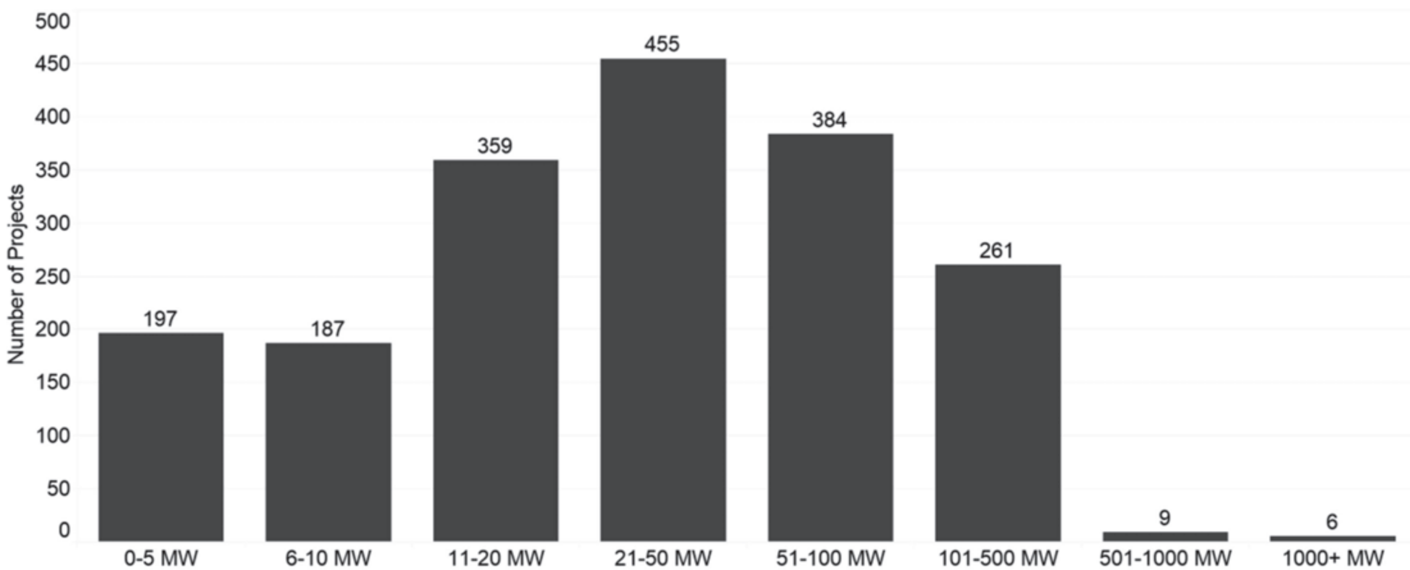
Generation Phase Progression: A – AG2
New Facility Requests



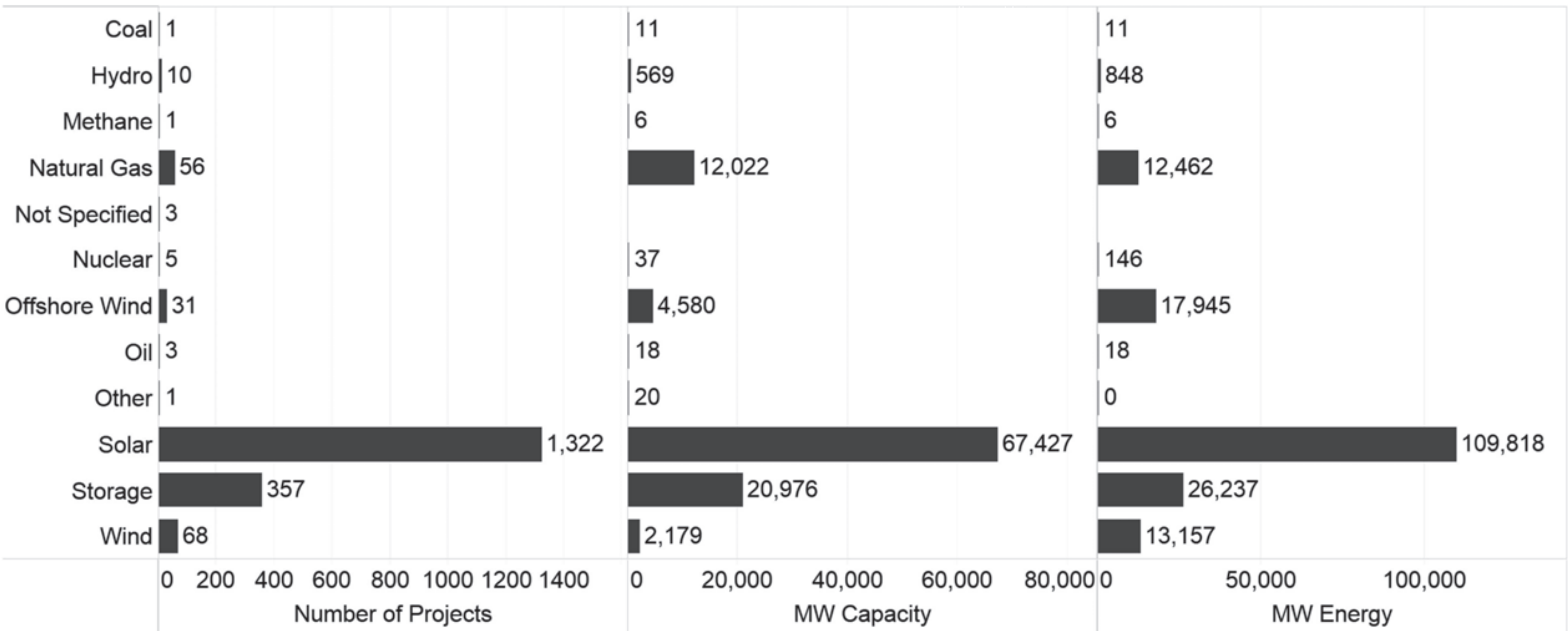
Generation Phase Progression: A – AG2
Uprate Generation Requests



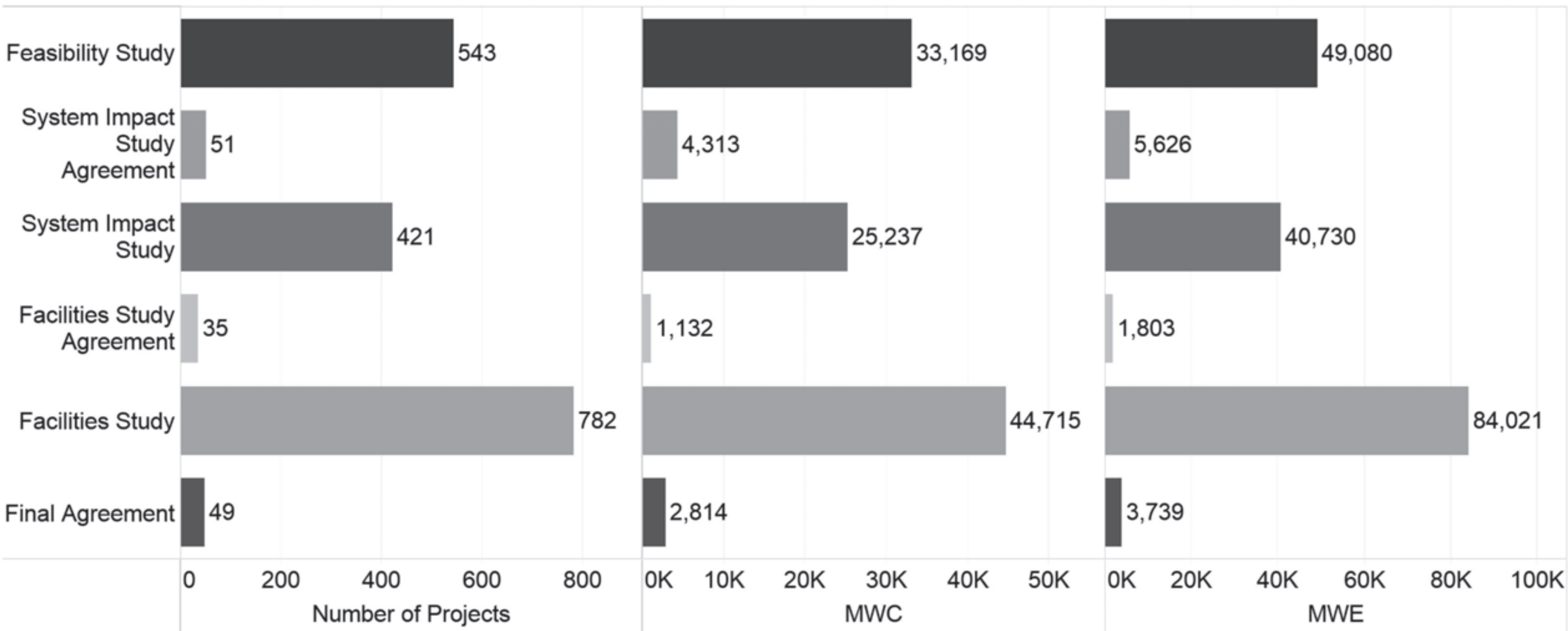
Active Projects in the Queue
Project Size Distribution



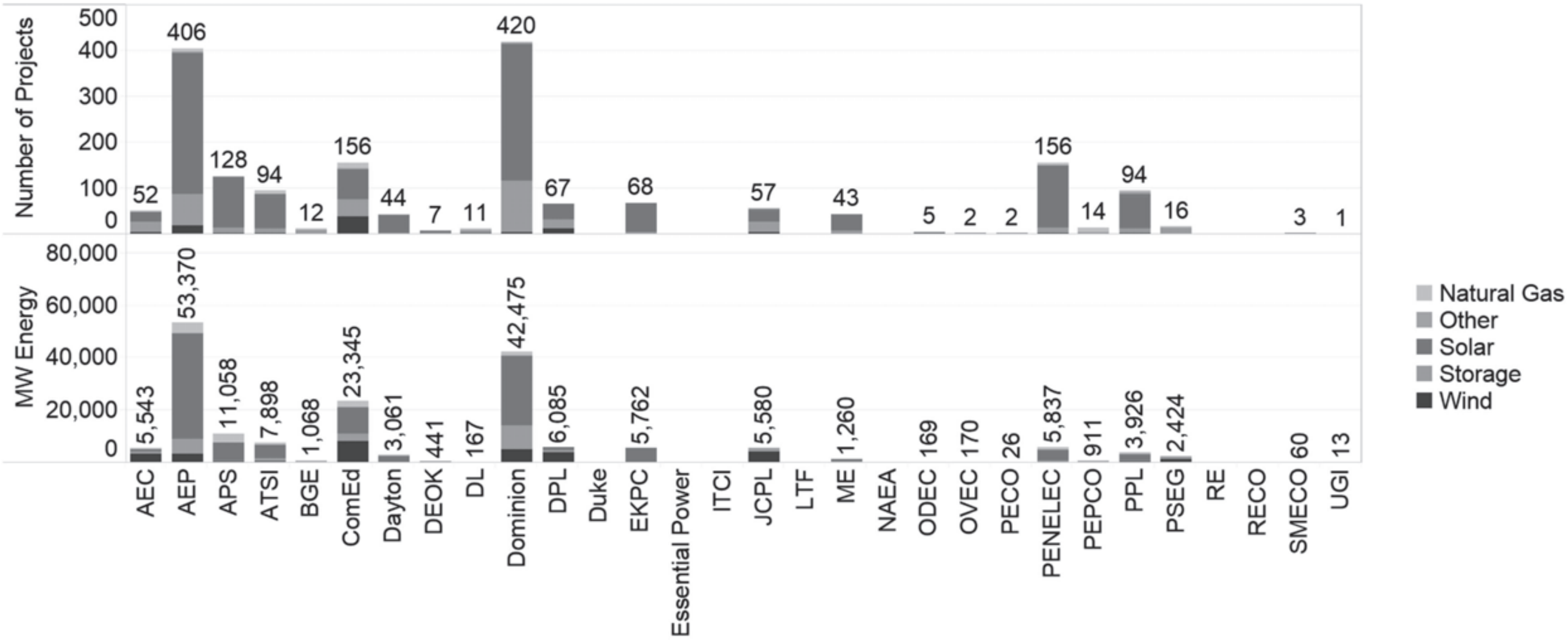
Active Projects in the Queue
Fuel Type Distribution



Active Projects in the Queue
Distribution of Study Phases



Active Projects in the Queue
Distribution by Transmission Owner Zone



Contact

Facilitator:
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David.Souder@pjm.com

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Molly.Mooney@pjm.com

SME:
Onyinye Caven,
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PJM Interconnection Queue Status Update

Member Hotline
(610) 666 – 8980
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custsvc@pjm.com

2023/2024 RPM Base Residual Auction Results

2023/2024 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins for the 2007/2008 through 2023/2024 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%
2022/2023	$ 50.00	144,477.3	19.9%
2023/2024	$ 34.13	144,870.6	20.3%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers
7) Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1)

2022/2023 RPM Base Residual Auction Results

Executive Summary

The 2022/2023 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 144,477.3 MW of unforced capacity in the RTO representing a 21.1% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2022/2023 Delivery Year as procured in the BRA is 19.9%, or 5.4% higher than the target reserve margin of 14.5%. This reserve margin was achieved at clearing prices that are between approximately 19% to 56% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in gas fired combined cycle generation, Energy Efficiency resources and new wind and solar resources.

The 2022/2023 BRA is the third 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 2021/2022 BRA, the 2022/2023 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. The 2022/2023 BRA is the first RPM auction conducted under the expanded application of the Minimum Offer Price Rule resulting from FERC's December 19, 2019 Order[1].

2022/2023 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2022/2023 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $50.00/MW-day. MAAC, EMAAC, BGE, COMED and DEOK were constrained LDAs in the 2022/2023 BRA with locational price adders, in regards to the immediate parent LDA, of $45.79/MW-day, $2.07/MW-day, $30.71/MW-day, $18.96/MW-day and $21.69/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2021/2022 BRA was $140.00/MW-day. Additionally, the EMAAC, PSEG, BGE, ATSI and COMED LDA were constrained LDAs in the 2021/2022 BRA with RCPs of $165.73/MW-day, $204.29/MW-day, $200.30/MW-day, $171.33/MW-day and $195.55/MW-day respectively.

2022/2023 BRA Resource Clearing Prices

	2022/23 BRA Resource Clearing Prices ($/MW-day)					
Capacity Type	Rest of RTO	MAAC	EMAAC	BGE	COMED	DEOK
Capacity Performance	$50.00	$95.79	$97.86	$126.50	$68.96	$71.69

[1] Docket Nos. EL16-49-000 EL18-178-000 (Consolidated)

Table 2 below provides a summary of the clearing prices by Constrained LDA. Resource Clearing Prices (RCPs) for the 2024/2025 BRA for CP Resources located in the rest of RTO declined from $34.13/MW-day to $28.92/MW-day. The number of constrained LDAs increased from 3 LDAs (MAAC, BGE, DPL-S) to 5 LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK). MAAC prices remained the same at $49.49/MW-day while price for the other 4 constrained LDAs increased: EMAAC increased from $49.49/MW-day to $54.95/MW-day, DPL-S increased from $69.95/MW-day to $90.64/MW-day, BGE increased by $69.95/MW-day to $73.00/MW-day, and DEOK increased from $34.13/MW-day to $96.24/MW-day.

Since the MAAC, EMAAC, DPL-South, BGE and DEOK were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2024/2025 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

Table 2 – Comparison of BRA Clearing Price by Delivery Year by Constrained LDA

		BRA Resource Clearing Prices ($/MW-day)")					
Capacity Type	BRA	Rest of RTO	MAAC	EMAAC	DPL-SOUTH	BGE	DEOK
Capacity Performance	2024/2025	$28.92	$49.49	$54.95	$90.64	$73.00	$96.24
Capacity Performance	2023/2024	$34.13	$49.49	$49.49	$69.95	$69.95	$34.13

INDIANA MICHIGAN POWER
An AEP Company
BOUNDLESS ENERGY

Indiana Michigan Power
P O Box 60
Fort Wayne, IN 46801
indianamichiganpower.com

January 5, 2022

Ohio Valley Electric Corporation
3932 U.S. Route 23
P.O. Box 468
Piketon, Ohio 45661

Dear Mr. Justin Cooper:

I am writing regarding the Inter-Company Power Agreement ("ICPA") related to the Ohio Valley Electric Corporation ("OVEC"). As you and I have discussed in multiple conversations, on May 13, 2021, the Michigan Public Service Commission (the "Commission") issued an Order in Indiana Michigan Power Company's ("I&M") 2020 power supply cost recovery ("PSCR") case (Case No. U-20529) concluding that I&M and OVEC are "affiliates" under the Commission's Code of Conduct.

In our conversations we have discussed that the Commission has directed I&M to make efforts to reduce its OVEC related costs and report on efforts to renegotiate the ICPA. Although I&M is not OVEC's affiliate under the Commission's Code of Conduct and I&M disagrees with the Commission's conclusions, I&M is making all reasonable steps to accommodate the spirit of the ultimate result of the Commission's decision with regard to OVEC to the extent possible.

A significant aspect of that Order, and of the parties' argument throughout the case, is concern that I&M has not tried to reduce costs by renegotiating the ICPA. In particular, the Commission stated that it "will expect to see evidence that the company has taken steps to minimize the cost of [power], including efforts to renegotiate contracts…"

In I&M's subsequent 2021 PSCR case (Case No. U-20804), the Commission explained "[a]s the Commission has repeatedly stated, the Commission will expect to see evidence that utilities have taken steps to minimize costs, including efforts to renegotiate contracts…" In that case, the Commission discussed Michigan's PSCR statute, MCL 460.6j(7), which provides that "[t]he commission may also indicate any cost items in the 5-year forecast that, on the basis of present evidence, the commission would be unlikely to permit the utility to recover from its customers in rates, rate schedules, or power supply cost recovery factors established in the future."

The Commission ultimately notified I&M in the final Order in Case No. U-20804 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."

Accordingly, in an effort to address the Commission's requirement that I&M attempt to renegotiate contracts, I&M requests that OVEC commence renegotiation discussions with I&M in a manner to reduce costs for I&M.

I&M looks forward to your response to this request. In the meantime, please let me know if I can provide additional information regarding the Commission orders described above or Michigan's regulatory framework.

Sincerely,

Steven F. Baker
President and COO
Indiana Michigan Power

OHIO VALLEY ELECTRIC CORPORATION
INDIANA-KENTUCKY ELECTRIC CORPORATION
3932 U. S. Route 23
P. O. Box 468
Piketon, Ohio 45661
740-289-7244

March 15, 2022

Steven Baker
President and CEO
Indiana Michigan Power
sfbaker@aep.com

Re: ICPA Renegotiation Request

Dear Mr. Baker:

I am writing in response to your letter dated January 5, 2022. In that letter you described a recent proceeding before the Michigan Public Service Commission and requested that OVEC provide Indiana Michigan Power ("I&M") any assistance it could in the renegotiation in the Inter-Company Power Agreement ("ICPA").

While OVEC appreciates your efforts on behalf of I&M customers, OVEC has no authority to make any modifications to the ICPA in this circumstance. Under Section 9.09 of the ICPA, any amendment to the ICPA requires unanimous approval of the Sponsoring Companies and OVEC.

> 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).

In light of the foregoing, unless I&M is able to obtain the consent of every other Sponsoring Company then OVEC has no authority to agree to any modifications whatsoever.

In addition, any amendment would require the approval of the Federal Energy Regulatory Commission ("FERC") under Section 205 of the Federal Power Act, as amended, since the ICPA is a FERC-regulated cost-based rate and any amendments are subject to FERC approval.

An amendment to the ICPA also would represent a modification to a contract between OVEC and its Sponsoring Companies. Many of the Sponsoring Companies are state-regulated public utilities, and thus such amendments require approval from state regulators that regulate inter-affiliate contracts involving utilities in such states. We believe any modification would require approval by state utility commissions in Kentucky and Virginia (and possibly others).

Finally, an amendment to the ICPA also may require advance consent from entities that have loaned OVEC money under various debt arrangements. Section 5.03 of the ICPA broadly describes the amounts recoverable through the "demand charges" as "equal to the total costs incurred for such month by [OVEC] resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities." The counterparties under OVEC's debt arrangements are unlikely to approve any amendment to the ICPA that alters in any way OVEC's recovery of all of such costs from the Sponsoring Companies under the ICPA.

If you have any questions or concerns please do not hesitate to contact me.

Very truly yours,

Justin Cooper

OVEC IKEC

OHIO VALLEY ELECTRIC CORPORATION INDIANA-KENTUCKY ELECTRIC CORPORATION
3932 U. S. Route 23
P. O. Box 468
Piketon, Ohio 45661
740-289-7244

April 12, 2022

Steven Baker
President and CEO Indiana
Michigan Power
sfbaker@aep.com

Re: OVEC Cost Reduction Efforts

Dear Mr. Baker:

I am writing in response to your request and our prior conversations regarding OVEC's efforts to continue to reduce costs. Please see the attached slides from the December 8, 2021 Board meeting which give representative examples of the recent cost savings measures.

As you can see highlighted, OVEC has implemented over 6,000 process improvements since 2015 which will lead to over $26 million in cost savings. OVEC has also reduced debt interest costs by approximately $9 million since 2019 via strategic refinancing. Finally, OVEC continues to seek operational efficiencies and has reduced staff by approximately 30% since 2015.

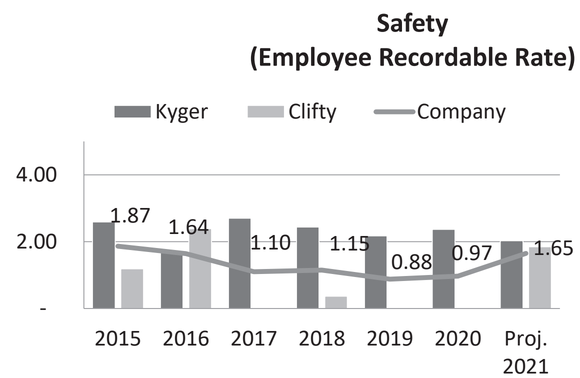
As we have discussed, OVEC is continually looking for opportunities to reduce costs and optimize performance. If you have any questions or concerns please do not hesitate to contact me.

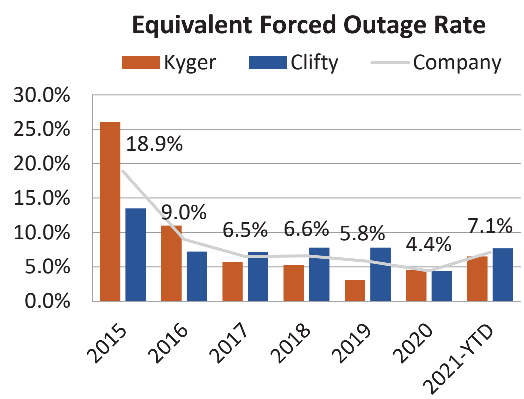
Very truly yours,

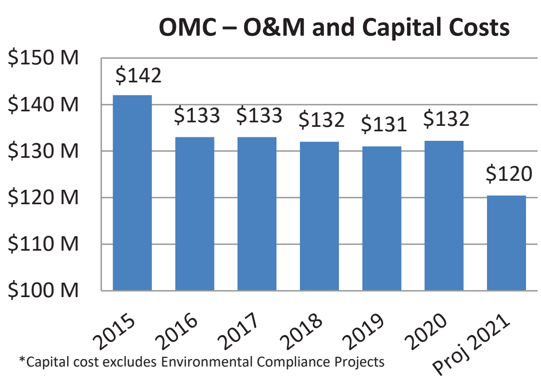
Justin Cooper

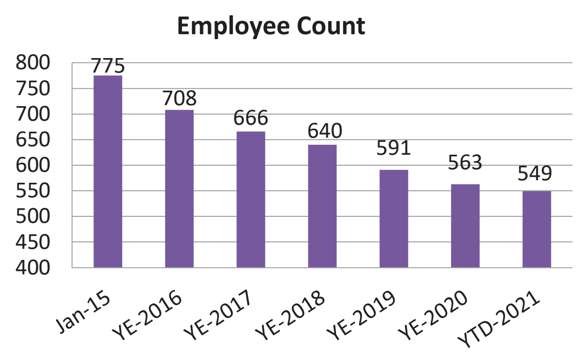
OVEC IKEC

2015 – 2021 Performance









Cost Optimization Efforts

Continuous Improvement/LEAN Efforts:

- o **Over 6,000 Process Improvements** (from employees) since 2015
- o **Over $26 million in cost saving ideas** (from employees) since 2015
- o In 2021 - Over 1,000 new process improvements and new standard work developed
- o For 2022 – OVEC will be targeting cost saving idea generation sessions at all locations to promote additional reductions to operating costs

Tax-Exempt Bond Refinancing Efforts:

- o Approx. $600 M of OVEC's $1.1 B of debt is tax-exempt (with ability to refinance)
- o Since 2019, through refinancing efforts, OVEC has reduced the weighted average interest rate on tax-exempt debt from 5.6% to 4.1%
  - o An estimated 150 Basis Point Reduction = approx. $9 M annual interest cost savings

Other Cost Reduction Efforts –Partnership with Alliance for Cooperative Energy Services (ACES)

- o OVEC has been partnering with ACES to outsource OVEC's Energy Scheduling function (in phases) over the past two years
- o **New Opportunity** - OVEC leveraging excess capacity in transmission operations and generation dispatch to serve ACES members
  - o In 2021, OVEC and ACES have implemented two pilot projects generating $175k in annual revenue from ACES to offset OVEC's costs.
  - o Additional ACES projects are being evaluated for additional revenue to reduce OVEC's cost to Sponsors

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
January 2021

EXHIBIT A
Page 1 of 2

		Attachment	Actual MWH		COST	Attachment
1	**GENERATION**					
2	Fossil Generation:		7,642		920,796	2
3	Nuclear Generation		1,708,554		7,966,461	2
4	Hydro Generation	1	6,674		0	
5	Solar Generation		776		62,468	3
6	SUBTOTAL		1,723,646	$	8,949,725	
			----------------		-----------------	
7	Emission Allowances		-		1,038	4
8	Consumables		-		256,083	5
9	Rockport Affiliated Transportation Adj.		-		-	6
			----------------		-----------------	
10	TOTAL GENERATION		1,723,646		9,206,846	
11	**Plus:**					
12	PURCHASES					
13	AEG Purchases/Assoc	7	5,350		13,174,490	7
14	OVEC	8	83,379		4,631,112	8
15	Other System Purchases/PJM Ancillaries	9	85,674		3,382,367	9
16	Wind Purchases	10	111,697		6,596,448	10
17	Cogeneration	11	121		3,738	11
18	FTR Rev Net of Congestion Costs-LSE		0		876,917	12
19	Transmission Losses		0		488,501	13
20	**Less:**					
21	Off-System Sales Margin (Sharing 100% eff 4/26)	15	836		(1,827,949)	15
22	Special Service Customers	14	0		0	14
23	Non-Firm Sales/Off-System Sales Rev -COGS	9	(125,707)		(2,290,334)	9
			-------------		-----------------	
24	TOTAL		1,884,996		34,242,136	
25	Total Power Supply Cost ($) - Line 24			$	34,242,136	
26	Net Energy Requirement (MWh) - Line 24				1,884,996	
27	Line 25 / Line 26 - Mills/KWh				18.17	
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh				**18.91**	
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)				**18.68**	
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH				**37.59**	
31	Less: Power Supply Cost Base - Mills/KWh				38.56	
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh				(0.97)	

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
February 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	473,612		13,517,288
3	Nuclear Generation	1,541,300		7,201,599
4	Hydro Generation	5,326		0
5	Solar Generation	908		73,094
6	SUBTOTAL	2,021,146	$	20,791,981
		----------------		-----------------
7	Emission Allowances	-		31,774
8	Consumables	-		1,751,582
9	Rockport Affiliated Transportation Adj.	-		(447,471)
		----------------		-----------------
10	TOTAL GENERATION	2,021,146		22,127,866
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	331,528		23,688,636
14	OVEC	81,771		4,470,956
15	Other System Purchases/PJM Ancillaries	76,271		4,337,239
16	Wind Purchases	122,050		7,140,585
17	Cogeneration	95		2,993
18	FTR Rev Net of Congestion Costs-LSE	0		2,171,878
19	Transmission Losses	0		1,467,159
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(297)		(12,286,512)
22	Special Service Customers	(602)		(31,830)
23	Non-Firm Sales/Off-System Sales Rev -COGS	(861,577)		(22,495,231)
		-------------		-----------------
24	TOTAL	1,770,385		30,593,739
25	Total Power Supply Cost ($) - Line 24		$	30,593,739
26	Net Energy Requirement (MWh) - Line 24			1,770,385
27	Line 25 / Line 26 - Mills/KWh			17.28
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**17.99**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**17.98**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**35.97**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			(2.59)

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
March 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	78,650		3,418,250
3	Nuclear Generation	1,689,100		7,922,883
4	Hydro Generation	7,891		0
5	Solar Generation	2,229		179,435
6	SUBTOTAL	1,777,870	$	11,520,568
		----------------		-----------------
7	Emission Allowances	-		6,017
8	Consumables	-		537,617
9	Rockport Affiliated Transportation Adj.	-		(31,523)
		----------------		-----------------
10	TOTAL GENERATION	1,777,870		12,032,679
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	55,055		14,703,936
14	OVEC	68,593		4,299,405
15	Other System Purchases/PJM Ancillaries	60,809		2,740,945
16	Wind Purchases	140,968		8,212,320
17	Cogeneration	58		1,788
18	FTR Rev Net of Congestion Costs-LSE	0		1,049,515
19	Transmission Losses	0		570,313
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	9,468		(473,691)
22	Special Service Customers	0		0
23	Non-Firm Sales/Off-System Sales Rev -COGS	(369,527)		(8,410,924)
		-------------		-----------------
24	TOTAL	1,743,294		34,726,286
25	Total Power Supply Cost ($) - Line 24		$	34,726,286
26	Net Energy Requirement (MWh) - Line 24			1,743,294
27	Line 25 / Line 26 - Mills/KWh			19.92
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**20.74**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**19.93**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**40.67**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			2.11

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
April 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	100,889		3,301,361
3	Nuclear Generation	1,185,663		6,103,524
4	Hydro Generation	6,970		0
5	Solar Generation	6,050		398,810
6	SUBTOTAL	1,299,572	$	9,803,695
7	Emission Allowances	-		6,017
8	Consumables	-		550,933
9	Rockport Affiliated Transportation Adj.	-		(1,105,834)
10	TOTAL GENERATION	1,299,572		9,254,811
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	70,622		16,074,173
14	OVEC	63,131		4,530,803
15	Other System Purchases/PJM Ancillaries	213,706		7,361,715
16	Wind Purchases	102,305		5,683,731
17	Cogeneration	134		4,227
18	FTR Rev Net of Congestion Costs-LSE	0		1,135,098
19	Transmission Losses	0		480,035
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(8,921)		(710,141)
22	Special Service Customers	0		0
23	Non-Firm Sales/Off-System Sales Rev -COGS	(176,079)		(3,500,371)
24	TOTAL	1,564,470		40,314,081
25	Total Power Supply Cost ($) - Line 24		$	40,314,081
26	Net Energy Requirement (MWh) - Line 24			1,564,470
27	Line 25 / Line 26 - Mills/KWh			25.77
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**26.83**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**21.49**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**48.32**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			9.76

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
May 2021

EXHIBIT A
Page 1 of 2

		Actual MWH		Actual COST
1	**GENERATION**	MWH		COST
2	Fossil Generation:	234,247		6,863,733
3	Nuclear Generation	1,063,159		5,203,978
4	Hydro Generation	5,732		0
5	Solar Generation	6,816		450,403
6	SUBTOTAL	1,309,954	$	12,518,114
		----------------		-----------------
7	Emission Allowances	-		13,318
8	Consumables	-		1,005,896
9	Rockport Affiliated Transportation Adj.	-		(1,950,257)
		----------------		-----------------
10	TOTAL GENERATION	1,309,954		11,587,071
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	163,973		18,156,803
14	OVEC	47,249		3,991,875
15	Other System Purchases/PJM Ancillaries	280,181		9,072,580
16	Wind Purchases	58,237		3,590,780
17	Cogeneration	57		1,760
18	FTR Rev Net of Congestion Costs-LSE	0		697,769
19	Transmission Losses	0		499,718
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(129)		(1,255,758)
22	Special Service Customers	0		0
23	Non-Firm Sales/Off-System Sales Rev -COGS	(186,300)		(4,041,786)
		-------------		-----------------
24	TOTAL	1,673,222		42,300,812
25	Total Power Supply Cost ($) - Line 24		$	42,300,812
26	Net Energy Requirement (MWh) - Line 24			1,673,222
27	Line 25 / Line 26 - Mills/KWh			25.28
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**26.32**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**20.76**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**47.08**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			8.52

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
June 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	435,646		12,779,237
3	Nuclear Generation	1,370,410		6,727,120
4	Hydro Generation	5,580		0
5	Solar Generation	6,828		448,016
6	SUBTOTAL	1,818,464	$	19,954,373
		----------------		-----------------
7	Emission Allowances	-		29,746
8	Consumables	-		763,251
9	Rockport Affiliated Transportation Adj.	-		(1,971,596)
		----------------		-----------------
10	TOTAL GENERATION	1,818,464		18,775,774
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	304,952		23,571,612
14	OVEC	64,231		4,351,909
15	Other System Purchases/PJM Ancillaries	144,904		5,751,093
16	Wind Purchases	86,140		4,818,944
17	Cogeneration	41		1,255
18	FTR Rev Net of Congestion Costs-LSE	0		2,198,057
19	Transmission Losses	0		1,198,430
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(102)		(1,310,935)
22	Special Service Customers	(207)		(12,981)
23	Non-Firm Sales/Off-System Sales Rev -COGS	(552,539)		(15,703,490)
		-------------		-----------------
24	TOTAL	1,865,884		43,639,668
25	Total Power Supply Cost ($) - Line 24		$	43,639,668
26	Net Energy Requirement (MWh) - Line 24			1,865,884
27	Line 25 / Line 26 - Mills/KWh			23.39
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**24.35**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**18.06**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**42.41**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			3.85

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
July 2021

EXHIBIT A
Page 1 of 2

		Actual MWH		Actual COST
1	**GENERATION**	MWH		COST
2	Fossil Generation:	405,892		13,575,832
3	Nuclear Generation	1,245,009		6,283,057
4	Hydro Generation	8,364		0
5	Solar Generation	6,639		439,542
6	SUBTOTAL	1,665,904	$	20,298,431
		----------------		-----------------
7	Emission Allowances	-		25,186
8	Consumables	-		1,712,750
9	Rockport Affiliated Transportation Adj.	-		(3,553,501)
		----------------		-----------------
10	TOTAL GENERATION	1,665,904		18,482,866
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	284,125		23,952,243
14	OVEC	87,607		4,806,451
15	Other System Purchases/PJM Ancillaries	201,281		9,367,854
16	Wind Purchases	40,703		2,350,340
17	Cogeneration	46		1,409
18	FTR Rev Net of Congestion Costs-LSE	0		809,003
19	Transmission Losses	0		1,231,306
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	107		(1,394,589)
22	Special Service Customers	(467)		(28,516)
23	Non-Firm Sales/Off-System Sales Rev -COGS	(349,532)		(9,397,485)
		-------------		-----------------
24	TOTAL	1,929,774		50,180,882
25	Total Power Supply Cost ($) - Line 24		$	50,180,882
26	Net Energy Requirement (MWh) - Line 24			1,929,774
27	Line 25 / Line 26 - Mills/KWh			26.00
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**27.07**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**17.98**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**45.05**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			6.49

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
August 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	394,444		12,667,412
3	Nuclear Generation	1,579,102		7,842,422
4	Hydro Generation	6,703		0
5	Solar Generation	6,200		418,863
6	SUBTOTAL	1,986,449	$	20,928,697
		----------------		-----------------
7	Emission Allowances	-		32,180
8	Consumables	-		1,526,996
9	Rockport Affiliated Transportation Adj.	-		(2,263,675)
		----------------		-----------------
10	TOTAL GENERATION	1,986,449		20,224,198
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	276,111		24,991,935
14	OVEC	87,228		4,834,550
15	Other System Purchases/PJM Ancillaries	144,138		8,748,149
16	Wind Purchases	43,379		2,307,121
17	Cogeneration	124		3,805
18	FTR Rev Net of Congestion Costs-LSE	0		586,343
19	Transmission Losses	0		1,587,712
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(54)		(1,028,573)
22	Special Service Customers	(528)		(44,847)
23	Non-Firm Sales/Off-System Sales Rev -COGS	(500,200)		(17,022,798)
		-------------		-----------------
24	TOTAL	2,036,647		45,187,595
25	Total Power Supply Cost ($) - Line 24		$	45,187,595
26	Net Energy Requirement (MWh) - Line 24			2,036,647
27	Line 25 / Line 26 - Mills/KWh			22.19
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**23.10**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**16.97**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**40.07**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			1.51

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
September 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	40,084		1,343,906
3	Nuclear Generation	1,582,426		7,738,338
4	Hydro Generation	5,246		0
5	Solar Generation	5,648		378,132
6	SUBTOTAL	1,633,404	$	9,460,376
7	Emission Allowances	-		1,149
8	Consumables	-		361,139
9	Rockport Affiliated Transportation Adj.	-		(124,327)
10	TOTAL GENERATION	1,633,404		9,698,337
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	28,059		14,318,772
14	OVEC	77,676		4,456,644
15	Other System Purchases/PJM Ancillaries	139,793		9,626,206
16	Wind Purchases	98,423		5,552,807
17	Cogeneration	47		1,436
18	FTR Rev Net of Congestion Costs-LSE	0		821,388
19	Transmission Losses	0		1,015,105
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	36		(2,706,615)
22	Special Service Customers	(243)		(23,370)
23	Non-Firm Sales/Off-System Sales Rev -COGS	(236,146)		(5,624,431)
24	TOTAL	1,741,049		37,136,279
25	Total Power Supply Cost ($) - Line 24		$	37,136,279
26	Net Energy Requirement (MWh) - Line 24			1,741,049
27	Line 25 / Line 26 - Mills/KWh			21.33
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**22.20**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**19.45**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**41.65**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			3.09

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
October 2021

EXHIBIT A
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		Actual MWH		Actual COST
1	**GENERATION**			
2	Fossil Generation:	0		(873,673)
3	Nuclear Generation	1,653,862		7,981,754
4	Hydro Generation	9,081		0
5	Solar Generation	2,762		187,587
6	SUBTOTAL	1,665,705	$	7,295,668
		----------------		-----------------
7	Emission Allowances	-		-
8	Consumables	-		223,406
9	Rockport Affiliated Transportation Adj.	-		-
		----------------		-----------------
10	TOTAL GENERATION	1,665,705		7,519,074
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	-		14,678,475
14	OVEC	38,091		3,744,534
15	Other System Purchases/PJM Ancillaries	69,176		6,341,293
16	Wind Purchases	85,920		4,820,052
17	Cogeneration	93		2,854
18	FTR Rev Net of Congestion Costs-LSE	0		1,495,938
19	Transmission Losses	0		1,550,351
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(27)		(6,329,668)
22	Special Service Customers	(96)		(8,479)
23	Non-Firm Sales/Off-System Sales Rev -COGS	(220,199)		(4,206,990)
		-------------		-----------------
24	TOTAL	1,638,663		29,607,434
25	Total Power Supply Cost ($) - Line 24		$	29,607,434
26	Net Energy Requirement (MWh) - Line 24			1,638,663
27	Line 25 / Line 26 - Mills/KWh			18.07
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**18.81**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**21.31**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**40.12**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			1.56

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
November 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	0		38,682
3	Nuclear Generation	1,633,797		7,736,939
4	Hydro Generation	8,071		0
5	Solar Generation	2,149		147,355
6	SUBTOTAL	1,644,017	$	7,922,976
		----------------		-----------------
7	Emission Allowances	-		1,017
8	Consumables	-		186,203
9	Rockport Affiliated Transportation Adj.	-		-
		----------------		-----------------
10	TOTAL GENERATION	1,644,017		8,110,196
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	-		12,221,119
14	OVEC	36,200		3,650,352
15	Other System Purchases/PJM Ancillaries	110,227		9,745,401
16	Wind Purchases	108,685		5,799,840
17	Cogeneration	38		1,211
18	FTR Rev Net of Congestion Costs-LSE	0		9,648,538
19	Transmission Losses	0		1,597,884
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(51)		(680,002)
22	Special Service Customers	0		0
23	Non-Firm Sales/Off-System Sales Rev -COGS	(192,197)		(5,597,437)
		-------------		-----------------
24	TOTAL	1,706,919		44,497,102
25	Total Power Supply Cost ($) - Line 24		$	44,497,102
26	Net Energy Requirement (MWh) - Line 24			1,706,919
27	Line 25 / Line 26 - Mills/KWh			26.07
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**27.14**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**19.68**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**46.82**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			8.26

INDIANA MICHIGAN POWER COMPANY
Determination of Power Supply Cost Recovery Factor
Michigan Jurisdiction
December 2021

EXHIBIT A
Page 1 of 2

		Actual		
1	**GENERATION**	MWH		COST
2	Fossil Generation:	230,226		7,556,035
3	Nuclear Generation	1,703,890		7,965,672
4	Hydro Generation	8,316		0
5	Solar Generation	1,543		105,596
6	SUBTOTAL	1,943,975	$	15,627,303
		----------------		-----------------
7	Emission Allowances	-		15,211
8	Consumables	-		885,435
9	Rockport Affiliated Transportation Adj.	-		(390,394)
		----------------		-----------------
10	TOTAL GENERATION	1,943,975		16,137,555
11	**Plus:**			
12	PURCHASES			
13	AEG Purchases/Assoc	161,158		18,317,803
14	OVEC	54,846		4,406,237
15	Other System Purchases/PJM Ancillaries	106,738		5,400,003
16	Wind Purchases	130,976		7,707,050
17	Cogeneration	47		1,576
18	FTR Rev Net of Congestion Costs-LSE	0		3,479,603
19	Transmission Losses	0		1,069,961
20	**Less:**			
21	Off-System Sales Margin (Sharing 100% eff 4/26)	(73)		(5,833,626)
22	Special Service Customers	0		0
23	Non-Firm Sales/Off-System Sales Rev -COGS	(654,154)		(17,618,178)
		-------------		-----------------
24	TOTAL	1,743,513		33,067,984
25	Total Power Supply Cost ($) - Line 24		$	33,067,984
26	Net Energy Requirement (MWh) - Line 24			1,743,513
27	Line 25 / Line 26 - Mills/KWh			18.97
28	Line 27 X 1.041 (4.1% Loss Factor) - Mills/KWh			**19.75**
29	Transmission Factor - Mills/KWH (See Exhibit A, Page 2)			**19.69**
30	Total Power Supply Cost Recovery (PSCR) Factor - Mills/KWH			**39.44**
31	Less: Power Supply Cost Base - Mills/KWh			38.56
32	Power Supply Cost Recovery (PSCR) Factor - Mills/KWh			0.88

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-3724

INDIANA MICHIGAN POWER COMPANY **ESTIMATE**
P. O. BOX 60 **05-Feb-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - January, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF January, 2021
KWH FOR THE MONTH 5,349,560

	SUMMARY	TOTAL
Current Month Bill:		
	Return on Common Equity	909,392
	Return on Other Capital	205,369
	Total Return	1,114,761
	Fuel	736,363
	Purchased Power	0
	Other Operating Revenues	(6,125)
	Other Operation and Maintenance Exp	1,284,926
	Depreciation Expense	1,182,300
	Taxes Other Than Federal Income Tax	105,368
	Federal Income Tax	(73,742)
	TOTAL UNIT POWER BILL	4,343,851
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	(162,869)
	TOTAL PRIOR MONTH'S ADJUSTMENTS	(162,869)
	TOTAL UNIT POWER BILL	4,180,983

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,444,619.72

DUE DATE - - - February 19, 2021

Cc: Steve Hornyak - Columbus; Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne; Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus; Kevin Amburgey-Columbus
Sid Lyons - Columbus; Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
09-Mar-21

UNIT 1
POWER BILL - - February, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF February, 2021
KWH FOR THE MONTH 210,388,070

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	904,272
Return on Other Capital	173,644
Total Return	1,077,916
Fuel	6,408,976
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,605,763
Depreciation Expense	1,182,451
Taxes Other Than Federal Income Tax	229,006
Federal Income Tax	(105,991)
TOTAL UNIT POWER BILL	10,391,996
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	10,391,996

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,983,019.81

DUE DATE - - - March 19, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Kevin Amburgey-Columbus
Michelle Howell - Columbus

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-3724

INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **07-Apr-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - March, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF March, 2021
KWH FOR THE MONTH 42,375,280

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	897,907
Return on Other Capital	276,174
Total Return	1,174,081
Fuel	1,699,730
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,072,551
Depreciation Expense	1,184,231
Taxes Other Than Federal Income Tax	282,654
Federal Income Tax	(154,513)
TOTAL UNIT POWER BILL	5,252,610
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel	0
Other Expenses (Includes taxes & interest)	24,013
TOTAL PRIOR MONTH'S ADJUSTMENTS	24,013
TOTAL UNIT POWER BILL	5,276,623

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,576,892.77

DUE DATE - - - April 22, 2021

Cc: Steve Hornyak - Columbus — Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne — Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus — Kevin Amburgey-Columbus
Sid Lyons - Columbus — Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
07-May-21

UNIT 1
POWER BILL - - April, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF April, 2021
KWH FOR THE MONTH 70,622,222

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	924,731
Return on Other Capital	68,101
Total Return	992,832
Fuel	2,580,879
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,529,257
Depreciation Expense	1,180,182
Taxes Other Than Federal Income Tax	359,283
Federal Income Tax	(163,263)
TOTAL UNIT POWER BILL	6,473,045
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	6,473,045

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,892,165.77

DUE DATE - - - May 21, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Kevin Amburgey-Columbus
Michelle Howell - Columbus

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-3724

INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **07-Jun-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - May, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF May, 2021
KWH FOR THE MONTH 163,972,870

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	948,923
Return on Other Capital	311,167
Total Return	1,260,090
Fuel	5,202,425
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,302,839
Depreciation Expense	1,180,087
Taxes Other Than Federal Income Tax	293,944
Federal Income Tax	(58,101)
TOTAL UNIT POWER BILL	9,175,158
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	9,175,158

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,972,733.15

DUE DATE - - - June 21, 2021

Cc: Steve Hornyak - Columbus — Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne — Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus — Kevin Amburgey-Columbus
Sid Lyons - Columbus — Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **14-Jul-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - June, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF June, 2021
KWH FOR THE MONTH 209,303,605

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	1,102,268
Return on Other Capital	328,062
Total Return	1,430,330
Fuel	6,600,243
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,215,461
Depreciation Expense	1,181,651
Taxes Other Than Federal Income Tax	(330,348)
Federal Income Tax	743,687
TOTAL UNIT POWER BILL	10,834,899
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	10,834,899

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

4,234,656.10

DUE DATE - - - July 19, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Kevin Amburgey-Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY | **ESTIMATE**
P. O. BOX 60 | **06-Aug-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - July, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF July, 2021
KWH FOR THE MONTH 129,595,880

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	651,020
Return on Other Capital	108,200
Total Return	759,220
Fuel	4,741,625
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,327,913
Depreciation Expense	1,223,431
Taxes Other Than Federal Income Tax	288,672
Federal Income Tax	(144,831)
TOTAL UNIT POWER BILL	8,189,904
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel	0
Other Expenses (Includes taxes & interest)	10,061
TOTAL PRIOR MONTH'S ADJUSTMENTS	10,061
TOTAL UNIT POWER BILL	8,199,965

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,458,340.37

DUE DATE - - - August 20, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Kevin Amburgey-Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
09-Sep-21

UNIT 1
POWER BILL - - August, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF August, 2021
KWH FOR THE MONTH 91,852,697

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	657,083
Return on Other Capital	157,482
Total Return	814,565
Fuel	3,334,586
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	956,680
Depreciation Expense	1,181,335
Taxes Other Than Federal Income Tax	280,290
Federal Income Tax	(146,081)
TOTAL UNIT POWER BILL	6,415,250
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	6,415,250

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,080,664.38

DUE DATE - - - August 20 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Kevin Amburgey-Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **06-Oct-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - September, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF September, 2021
KWH FOR THE MONTH 0

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	642,181
Return on Other Capital	148,995
Total Return	791,176
Fuel	66,376
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	1,054,388
Depreciation Expense	1,608,704
Taxes Other Than Federal Income Tax	345,016
Federal Income Tax	(40,440)
TOTAL UNIT POWER BILL	3,819,096
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	3,819,096

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,752,719.70

DUE DATE - - - October 18, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Kevin Amburgey-Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY **ESTIMATE**
P. O. BOX 60 **06-Nov-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - October, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF October, 2021
KWH FOR THE MONTH 1

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	561,991
Return on Other Capital	130,397
Total Return	692,388
Fuel	(330,387)
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	2,080,011
Depreciation Expense	1,973,089
Taxes Other Than Federal Income Tax	488,447
Federal Income Tax	307,412
TOTAL UNIT POWER BILL	5,204,835
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	5,204,835

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

5,535,222.44

DUE DATE - - - November 19, 2021
Cc: Steve Hornyak - Columbus Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus Kevin Amburgey-Columbus
Sid Lyons - Columbus Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **07-Dec-21**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - November, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF November, 2021
KWH FOR THE MONTH 1

	SUMMARY	TOTAL
Current Month Bill:		
	Return on Common Equity	542,237
	Return on Other Capital	117,519
	Total Return	659,756
	Fuel	77,157
	Purchased Power	0
	Other Operating Revenues	(6,125)
	Other Operation and Maintenance Exp	1,541,016
	Depreciation Expense	1,372,362
	Taxes Other Than Federal Income Tax	95,799
	Federal Income Tax	(647,114)
	TOTAL UNIT POWER BILL	3,092,851
Prior Month's Adjustment:		
	Return on Common Equity & Other Capital	0
	Fuel	0
	Other Expenses (Includes taxes & interest)	154,442
	TOTAL PRIOR MONTH'S ADJUSTMENTS	154,442
	TOTAL UNIT POWER BILL	3,247,293

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

3,170,135.70

DUE DATE - - - December 19, 2021

Cc: Steve Hornyak - Columbus; Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne; Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus; Kevin Amburgey-Columbus
Sid Lyons - Columbus; Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **07-Jan-22**
FORT WAYNE, IN 46801

UNIT 1
POWER BILL - - December, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF December, 2021
KWH FOR THE MONTH 1

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	589,172
Return on Other Capital	147,687
Total Return	736,859
Fuel	199,948
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	764,434
Depreciation Expense	1,416,627
Taxes Other Than Federal Income Tax	329,816
Federal Income Tax	(378,673)
TOTAL UNIT POWER BILL	3,062,885
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel	0
Other Expenses (Includes taxes & interest)	60,136
TOTAL PRIOR MONTH'S ADJUSTMENTS	60,136
TOTAL UNIT POWER BILL	3,123,022

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

2,923,073.63

DUE DATE - - - January 21, 2022

Cc: Steve Hornyak - Columbus — Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne — Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus — Kevin Amburgey-Columbus
Sid Lyons - Columbus — Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY **ESTIMATE**
P. O. BOX 60 **05-Feb-21**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - January, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF January, 2021
KWH FOR THE MONTH 0

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	(80,916)
Return on Other Capital	(18,273)
Total Return	(99,189)
Fuel	76,408
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,732,376
Depreciation Expense	4,415,213
Taxes Other Than Federal Income Tax	111,437
Federal Income Tax	(73,742)
TOTAL CURRENT UNIT POWER BILL	9,156,378
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	(162,870)
TOTAL PRIOR MONTH'S ADJUSTMENTS	(162,870)
TOTAL UNIT POWER BILL	8,993,508

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

8,917,099.77

DUE DATE - - February 19, 2021
Cc: Steve Hornyak - Columbus Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **09-Mar-21**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - February, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF February, 2021
KWH FOR THE MONTH 121,140,410

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	(89,326)
Return on Other Capital	(17,153)
Total Return	(106,479)
Fuel	3,808,516
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	5,039,509
Depreciation Expense	4,432,135
Taxes Other Than Federal Income Tax	235,075
Federal Income Tax	(105,991)
TOTAL CURRENT UNIT POWER BILL	13,296,640
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	0
TOTAL PRIOR MONTH'S ADJUSTMENTS	0
TOTAL UNIT POWER BILL	13,296,640

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

9,488,123.90

DUE DATE - - March 19, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY **ESTIMATE**
P. O. BOX 60 **07-Apr-21**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - March, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF March, 2021
KWH FOR THE MONTH 12,679,547

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	(116,993)
Return on Other Capital	(35,984)
Total Return	(152,977)
Fuel	989,211
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,080,670
Depreciation Expense	4,358,311
Taxes Other Than Federal Income Tax	288,723
Federal Income Tax	(154,513)
TOTAL CURRENT UNIT POWER BILL	9,403,300
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	24,013
TOTAL PRIOR MONTH'S ADJUSTMENTS	24,013
TOTAL UNIT POWER BILL	9,427,313

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

8,438,102.41

DUE DATE - · April 22, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
07-May-21

UNIT 2
POWER BILL - - April, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF April, 2021
KWH FOR THE MONTH 0

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	(141,450)
Return on Other Capital	(10,417)
Total Return	(151,867)
Fuel	64,289
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,998,895
Depreciation Expense	4,493,847
Taxes Other Than Federal Income Tax	365,352
Federal Income Tax	(163,263)
TOTAL CURRENT UNIT POWER BILL	9,601,129
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	(0)
TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
TOTAL UNIT POWER BILL	9,601,129

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

9,536,839.68

DUE DATE - · May 21, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY **ESTIMATE**
P. O. BOX 60 **07-Jun-21**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - May, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF May, 2021

SUMMARY	TOTAL
KWH FOR THE MONTH	0
Current Month Bill:	
Return on Common Equity	(162,113)
Return on Other Capital	(53,159)
Total Return	(215,272)
Fuel	26,057
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,437,939
Depreciation Expense	4,497,135
Taxes Other Than Federal Income Tax	300,013
Federal Income Tax	(58,101)
TOTAL CURRENT UNIT POWER BILL	8,981,645
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	(0)
TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
TOTAL UNIT POWER BILL	8,981,645

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

8,955,587.88

DUE DATE - · June 21, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
14-Jul-21

UNIT 2
POWER BILL - - June, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF June, 2021
KWH FOR THE MONTH 95,648,726

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	(353,611)
Return on Other Capital	(105,244)
Total Return	(458,855)
Fuel	3,257,389
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,834,397
Depreciation Expense	4,747,706
Taxes Other Than Federal Income Tax	(381,486)
Federal Income Tax	743,687
TOTAL CURRENT UNIT POWER BILL	12,736,713
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	0
TOTAL PRIOR MONTH'S ADJUSTMENTS	0
TOTAL UNIT POWER BILL	12,736,713

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

9,479,324.08

DUE DATE - · July 19, 2021
Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **06-Aug-21**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - July, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF July, 2021
KWH FOR THE MONTH 154,528,710

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	262,478
Return on Other Capital	43,624
Total Return	306,102
Fuel	5,647,165
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	5,180,047
Depreciation Expense	4,465,118
Taxes Other Than Federal Income Tax	294,741
Federal Income Tax	(144,831)
TOTAL CURRENT UNIT POWER BILL	15,742,217
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	10,061
TOTAL PRIOR MONTH'S ADJUSTMENTS	10,061
TOTAL UNIT POWER BILL	15,752,278

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

10,105,112.71

DUE DATE - · August 20, 2021
Cc: Steve Hornyak - Columbus — Kurt C Cooper - Ft Wayne
Dave Hille - Ft. Wayne — Shannon Listebarger - Columbus
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus — Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **09-Sep-21**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - August, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF August, 2021
KWH FOR THE MONTH 184,258,475

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	231,740
Return on Other Capital	55,541
Total Return	287,281
Fuel	6,379,427
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	5,099,824
Depreciation Expense	4,511,503
Taxes Other Than Federal Income Tax	286,359
Federal Income Tax	(146,081)
TOTAL CURRENT UNIT POWER BILL	16,412,189
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	(0)
TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
TOTAL UNIT POWER BILL	16,412,189

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

10,032,761.34

DUE DATE - · August 20 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
06-Oct-21

UNIT 2
POWER BILL - - September, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF September, 2021
KWH FOR THE MONTH 28,058,630

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	217,655
Return on Other Capital	50,499
Total Return	268,154
Fuel	1,080,894
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,761,941
Depreciation Expense	4,084,168
Taxes Other Than Federal Income Tax	351,085
Federal Income Tax	(40,440)
TOTAL CURRENT UNIT POWER BILL	10,499,676
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	0
TOTAL PRIOR MONTH'S ADJUSTMENTS	0
TOTAL UNIT POWER BILL	10,499,676

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

9,418,782.47

DUE DATE - - October 18, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-3724

INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
06-Nov-21

UNIT 2
POWER BILL - - October, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF October, 2021
KWH FOR THE MONTH 1

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	239,508
Return on Other Capital	55,572
Total Return	295,080
Fuel	(20,199)
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,654,935
Depreciation Expense	3,748,020
Taxes Other Than Federal Income Tax	494,516
Federal Income Tax	307,412
TOTAL CURRENT UNIT POWER BILL	9,473,640
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	(0)
TOTAL PRIOR MONTH'S ADJUSTMENTS	(0)
TOTAL UNIT POWER BILL	9,473,640

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

9,493,838.79

DUE DATE - · November 19, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-3724

INDIANA MICHIGAN POWER COMPANY
P. O. BOX 60
FORT WAYNE, IN 46801

ESTIMATE
07-Dec-21

UNIT 2
POWER BILL - - November, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF November, 2021
KWH FOR THE MONTH 1

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	211,727
Return on Other Capital	45,888
Total Return	257,615
Fuel	130,523
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	4,629,423
Depreciation Expense	4,353,194
Taxes Other Than Federal Income Tax	101,868
Federal Income Tax	(647,114)
TOTAL CURRENT UNIT POWER BILL	8,819,384
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	154,442
TOTAL PRIOR MONTH'S ADJUSTMENTS	154,442
TOTAL UNIT POWER BILL	8,973,826

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

8,843,302.92

DUE DATE - December 19, 2021

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

AEP GENERATING COMPANY
ONE RIVERSIDE PLAZA,COLUMBUS,OH 43215
TELEPHONE (614) 716-3724

INDIANA MICHIGAN POWER COMPANY — **ESTIMATE**
P. O. BOX 60 — **07-Jan-22**
FORT WAYNE, IN 46801

UNIT 2
POWER BILL - - December, 2021

IN ACCORDANCE WITH POWER AGREEMENT DATED OCTOBER 1, 1984 (AS AMENDED)
ENERGY DELIVERED FOR THE MONTH OF December, 2021
KWH FOR THE MONTH 161,158,406

SUMMARY	TOTAL
Current Month Bill:	
Return on Common Equity	106,546
Return on Other Capital	26,708
Total Return	133,254
Fuel	5,651,275
Purchased Power	0
Other Operating Revenues	(6,125)
Other Operation and Maintenance Exp	5,065,352
Depreciation Expense	4,333,677
Taxes Other Than Federal Income Tax	335,884
Federal Income Tax	(378,673)
TOTAL CURRENT UNIT POWER BILL	15,134,645
Prior Month's Adjustment:	
Return on Common Equity & Other Capital	0
Fuel Expense	0
Other Expenses (Includes taxes & interest)	60,136
TOTAL PRIOR MONTH'S ADJUSTMENTS	60,136
TOTAL UNIT POWER BILL	15,194,781

AMOUNTS WILL BE PAID DIRECT FROM GENERAL FUNDS.

9,543,505.98

DUE DATE - January 21, 2022

Cc: Steve Hornyak - Columbus
Dave Hille - Ft. Wayne
Mike Stout - Ft. Wayne
Mike Giardina - Columbus
Sid Lyons - Columbus
Kurt C Cooper - Ft Wayne
Shannon Listebarger - Columbus
Michelle Howell - Columbus

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

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

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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

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

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

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:

$$\text{Actual experienced daily burn} = 24 \text{ hours} \left(\frac{\text{Tons burned per year}}{\text{Operating hours}}\right)$$

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:

$$\frac{\text{kW of curtailed capacity}}{\text{kW of rated capacity}} \times \text{Curtailment hours}$$

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
MICHIGAN PUBLIC SERVICE COMMISSION
ATTORNEY GENERAL
DATA REQUEST SET NO. 2
CASE NO. U-20805

DATA REQUEST NO. AG 2-29

Request

Refer to the Direct Testimony of Company Witness Ray, page 10, regarding the exclusion of affiliate transportation costs from the PSCR.

a. Explain where I&M recovers the costs associated with transportation services provided by an affiliate.
b. Indicate whether I&M is allowed to recover costs associated with transportation services provided by an affiliate through PSCR.
c. Indicate the state statute that provides for the recovery of affiliate transportation costs through base rates.
d. Indicate whether I&M receives a rate of return on the costs associated with transportation services provided by affiliates. If yes, provide the return rate.
e. Provide the total transportation costs incurred in 2021, and which of those will be recovered through the PSCR, broken down transportation company.
f. Provide the total affiliate transportation costs incurred in 2021, and which of those will not be recovered through the PSCR.
g. Indicate what portion of total transportation costs incurred in 2021 are associated with affiliates and what portion is associated with non-affiliates.
h. Indicate whether it is I&M's understanding that the Company is required, under the Michigan Code of conduct, to not pay an affiliate above market prices for transportation services.
i. Provide all analyses I&M has completed that demonstrates that the Company is not paying above market prices for transportation services from an affiliate.

Response

a – d, h and i: I&M objects to these subparts on the grounds that they seek information 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, I&M states these costs are not recovered in the PSCR Clause and factors.
e. See AG 2-30 Confidential Attachment 1 for a breakdown of all non-affiliate transportation costs which are recovered through the PSCR.
f and g. See Exhibit IM-4, line 3 for the affiliate amount. Exhibit IM-1 details the non-affiliate transportation costs.

Objection
Counsel

Preparer

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
ATTORNEY GENERAL
DATA REQUEST SET NO. 2
CASE NO. U-20805

Ray

9656
2-12-91

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for authority to increase its rates for the sale of electric energy.	)	Case No. U-9656

At the February 12, 1991 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Steven M. Fetter, Chairman
Hon. William E. Long, Commissioner
Hon. Ronald E. Russell, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

On June 18, 1990, Indiana Michigan Power Company (I&M) filed an application, with supporting testimony and proposed exhibits, requesting authority to increase its retail electric rates by an annual amount of approximately $15,821,000 and to make certain changes to the design of its tariffs and to its terms and conditions of service.

Pursuant to due notice, a prehearing conference was held on August 3, 1990 before Administrative Law Judge Theodora M. Mace, substituting for Adminstrative Law Judge Robert L. Shankland. I&M, the Commission Staff (Staff), the Association of Businesses Advocating Tariff Equity (ABATE), and Whirlpool Corporation and Southern Michigan Cold Storage Company (Whirlpool/Southern Michigan) participated in the proceedings.

In November and December 1990 and January 1991, the Staff, ABATE, Whirlpool/ Southern Michigan, and I&M engaged in settlement discussions. The parties reached an agreement, and a settlement agreement signed by all parties, a copy of which is attached as Appendix A, was submitted.

The settlement agreement provides, among other things, that I&M's Michigan jurisdictional retail electric revenues should be increased by $10,400,000 annually, to be made effective in two steps. The amount of the Step One increase is $7,400,000, which is proposed to be effective for service rendered on and after April 1, 1991. The amount of the Step Two increase is $3,000,000, which is proposed to be effective for service rendered on and after April 1, 1992. The Step Two increase includes an increase of $1,325,000 to the annual Michigan jurisdictional provision for decommissioning I&M's Donald C. Cook Nuclear Plant. Exhibits A and B to the settlement agreement are the tariff sheets reflecting the Step One and Step Two increases, respectively.

Both Rule 33 of the Commission's Rules of Practice and Procedure, R 460.43, and Section 78 of the Administrative Procedures Act of 1969, MCL 24.278, provide for the disposition of matters by stipulation and agreement. Those provisions do not relieve the Commission of its responsibility to determine whether the stipulation of the parties is in the public interest.

After a review of the settlement agreement in this case, we find it is reasonable and in the public interest and should be approved.

Although the process of settlement involves compromise, the Commission views it as an opportunity for parties to resolve their disputes fairly and expeditiously. A solution devised by the parties themselves is more likely to fit their needs and circumstances. A settlement also conserves the scarce resources of the parties and the Commission. For these reasons, and as long as it can be demonstrated that the public interest is served by a particular settlement, the Commission encourages parties to settle their disputes.

The Commission finds that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, 1979 Administrative Code, R 460.11 et seq.

b. The settlement agreement is reasonable and in the public interest, and should be approved in its entirety.

c. I&M should be authorized to increase its rates for the sale of electricity in two steps, as provided in the settlement agreement.

d. I&M should be authorized to change its power supply cost recovery basing point and adjust its power supply cost recovery factor, as provided in the settlement agreement.

e. The capacity charges related to the purchase of Rockport Plant Unit No. 2 capacity by I&M from AEP Generating Company should be approved for the purposes of MCL 460.6j(13)(b), as provided in the settlement agreement.

f. The proposed language satisfying the disclosure requirements for nuclear decommissioning expense set forth in Exhibit C to the settlement agreement is reasonable and should be incorporated into this order by reference.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement attached as Appendix A, is approved in its entirety. Due to their length, the exhibits to the settlement agreement, which are contained in the official docket, are made part of this order by reference.

B. Indiana Michigan Power Company is authorized to increase its rates by $10,400,000 annually for the sale of electricity as described in the settlement agreement, without further order of the Commission.

C. Indiana Michigan Power Company shall file, within 30 days of the effective dates of the Step One and Step Two increases, respectively, tariff sheets in substantial compliance with those referenced as Exhibits A and B to the settlement agreement.

D. Indiana Michigan Power Company is authorized to change its power supply cost recovery basing point and adjust its power supply cost recovery factor, as provided in the settlement agreement.

E. The capacity charges related to the purchase of Rockport Plant Unit No. 2 capacity by Indiana Michigan Power Company from AEP Generating Company are approved for purposes of MCL 460.6j(13)(b), as provided in the settlement agreement.

F. The language addressing the disclosure requirements for nuclear decommissioning expense set forth in Exhibit C to the settlement agreement is incorporated into this order by reference.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ Steven M. Fetter
Chairman

(S E A L)

/s/ William E. Long
Commissioner

/s/ Ronald E. Russell
Commissioner

By its action of February 12, 1991.

/s/ Dorothy Wideman
Its Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of INDIANA MICHIGAN POWER COMPANY for Authority to Increase its Rates for the Sale of Electric Energy.	Case No. U-9656

SETTLEMENT AGREEMENT

For the purpose of settling the issues in the above captioned proceeding only, and subject to the acceptance and approval of the Michigan Public Service Commission (Commission) without modification, and without prejudice to the pre-negotiation positions of the parties in this or any other proceeding, the parties hereto agree and stipulate as follows:

On June 18, 1990, Indiana Michigan Power Company (I&M) filed its Application, together with the prepared testimony and proposed exhibits of its witnesses in support of the Application, requesting authority to amend its electric rate schedules to increase jurisdictional operating revenues by approximately $15,821,000 annually. I&M's Application, testimony and exhibits also proposed certain changes to the design of its electric tariffs and to its Terms and Conditions of Service, including a reduction of the Power Supply Cost Recovery (PSCR) basing point.

Pursuant to the Commission's Notice of Hearing dated June 28, 1990, I&M gave notice to its customers by publishing a Notice of Hearing in its Michigan electric service area, as well as by serving a copy of the Commission's Notice of Hearing upon all cities, incorporated villages, townships and counties within I&M's Michigan electric service area and upon all Intervenors who appeared in Case Nos. U-7791 and U-9458 (I&M's last base rate case and 1990 PSCR Plan case). I&M's Proof of Service and Affidavits of Publication were filed with the Commission on August 3, 1990.

Pursuant to the Notice of Hearing, a prehearing conference was held on August 3, 1990, at the Commission's offices in Lansing, Michigan, before Administrative Law Judge (ALJ) Theodora M. Mace, who was substituting for ALJ Robert Shankland. At that prehearing conference, the Petitions to Intervene of the Association of Businesses Advocating Tariff Equity (ABATE) and of Whirlpool Corporation and Southern Michigan Cold Storage Company (Whirlpool/Southern Michigan) were granted. In addition, the Commission Staff (Staff) appeared.

The Staff conducted an audit of I&M's books and records, the parties engaged in discovery, and settlement discussions took place among the parties in November and December, 1990 and January, 1991.

Encouraged by the Commission's Rules of Practice and Procedure (Rule 33; 1979 AC, R 460.43), I&M, Staff, Whirlpool/Southern Michigan and ABATE have resolved, through settlement negotiations, the contested issues in this proceeding as set forth in this Settlement Agreement.

It is the opinion of the parties hereto that this Settlement Agreement will promote the public interest, will aid the expeditious conclusion of this case, and will minimize the time and expense which would otherwise have to be devoted to this matter by the Commission and all of the parties. This Settlement Agreement is for the sole purpose of resolving this case and all provisions of the same are dependent upon all other provisions contained herein.

In addition to the foregoing, the parties specifically agree as follows:

1. Based upon a projected test year ending December 31, 1991, I&M has a revenue deficiency from its Michigan jurisdictional retail sales of electric energy in the annual amount of $10,400,000, which includes an

increase in the provision for nuclear decommissioning of $1,325,000. The parties agree to the jurisdictional retail revenue deficiency of $10,400,000, but not necessarily to the individual components or amounts which may have been considered in the determination of that deficiency, except for those components or amounts specifically set forth in this Settlement Agreement.

2. A cost rate for I&M's common equity of 13.00% has been used in arriving at the revenue deficiency in Paragraph 1. The Staff used this rate to determine an overall rate of return for I&M of 9.46%. By this Settlement Agreement, the parties only agree to the cost rate for common equity.

3. I&M's jurisdictional retail electric rates should be revised as shown on Exhibits A and B attached hereto to increase I&M's revenues by the amount of the annual revenue deficiency in two steps (Step One and Step Two). The Step One increase in the amount of $7,400,000, should be made effective for service rendered on and after April 1, 1991 (Exhibit A). The Step Two increase, in the amount of $3,000,000, should be made effective for service rendered on and after April 1, 1992 (Exhibit B).

4. The total annual Michigan jurisdictional provision for decommissioning the Donald C. Cook Nuclear Plant should be $2,363,000, which is an increase of $1,325,000 over the current annual jurisdictional provision. It is further agreed that the Commission's final order in this proceeding should incorporate language proposed by I&M to satisfy the disclosure requirements of the Internal Revenue Service (IRS), which is set forth in Exhibit C attached hereto. The parties agree that the increase in the annual jurisdictional provision for nuclear decommissioning should be made effective on April 1, 1992, as part of the $3,000,000 Step Two

increase. It is agreed that the annual jurisdictional provision will continue to be collected as a separate surcharge on the base rates charged to customers, determined using the methodology approved by the Commission in Case No. U-8559, and that the current separate surcharge will continue in effect until increased as a part of the Step Two increase.

5. I&M agrees that it will not file a rate application requesting an increase in its base retail electric rates before July 1, 1992. This filing moratorium shall also apply, for the same period, to applications requesting other non-PSCR related rate increases, including increases in the nuclear decommissioning surcharge, except for limited purpose proceedings addressing: (i) energy conservation surcharges, (ii) the effect on rates of federal or state tax law changes affecting I&M's annual jurisdictional revenue requirement by $1,000,000 or more, or (iii) implementation of the DSS Positive Billing Program or similar government mandated programs.

6. I&M agrees that it will not propose to make tariffs effective which increase the number of on-peak hours from the number incorporated in the present case prior to April 1, 1994.

7. The determination of the revenue deficiency specified in this Settlement Agreement incorporates the effects of the revised depreciation accrual rates for I&M approved in Case Nos. U-9231 and U-9591.

8. The determination of the revenue deficiency specified in this Settlement Agreement does not include the recovery of any costs associated with I&M's Energy Conservation Services (ECS) Program.

9. Pursuant to the Commission's Opinion and Order dated November 21, 1990 in I&M's 1990 PSCR Plan case (Case No. U-9458), the parties have considered all of the effects on I&M's cost of service of the addition of

Rockport Plant Unit No. 2 (Rockport 2) to I&M's available generating capacity. Based on the evaluation of all of the cost-of-service effects, including capacity settlement effects, the parties agree that I&M's Michigan ratepayers are being fairly compensated for I&M's contribution of generating capacity to the AEP System, including Rockport 2. In recognition of this, effective April 1, 1991, the costs associated with I&M's leased share of Rockport 2 are included in calculating the total revenue deficiency agreed upon in this Settlement Agreement. Notwithstanding the revenue deficiency agreed to in this Settlement Agreement, any party may challenge the inclusion of I&M's leased share of Rockport 2 costs in the rates charged to I&M's Michigan customers in a future general rate case or other appropriate proceeding.

10. In recognition of the fact that I&M's Michigan ratepayers are being fairly compensated for the costs of the purchase of Rockport 2 capacity by I&M from AEP Generating Company (AEG), the parties agree that the capacity charges associated with the purchase of Rockport 2 capacity by I&M from AEG should be approved for purposes of MCL 460.6j(13)(b); MSA 22.13(6j)(13)(b). The parties explicitly recognize that any party may challenge the inclusion of capacity charges associated with the purchase of Rockport 2 capacity by I&M from AEG in rates charged to Michigan ratepayers in a future PSCR proceeding if circumstances change such that Michigan ratepayers are no longer fairly compensated for the cost of the generating capacity which I&M makes available to the AEP System. In any future proceeding, nothing herein shall be construed as an agreement by I&M nor any other party as to the validity of such a challenge, the extent of Commission jurisdiction with

respect to Rockport 2 costs or the appropriate standard for determining the recoverability of such costs.

11. The PSCR-related effects of Rockport 2, including the capacity charges related to the purchase of Rockport 2 capacity by I&M from AEG, and all of the capacity settlement effects of Rockport 2, should be reflected in I&M's PSCR factor on and after the effective date of the Step One increase. The annual PSCR-related effects of Rockport 2 are estimated on Exhibit D attached hereto. It is further agreed that I&M's power supply cost basing point shall be changed from 9.62 mills per kwh to 3.33 mills per kwh and I&M shall adjust for billing purposes its PSCR factor to reflect such change in the PSCR cost basing point. Both the change in the power supply cost basing point and the adjustment to the PSCR factor shall become effective for service rendered on and after the effective date of the Step One increase. I&M will use its best efforts to adjust its 1991 PSCR factor to insure that there is no underrecovery of PSCR revenues in 1991 caused solely by the exclusion of Rockport 2 effects from January 1, 1991 to the effective date of the Step 1 increase pursuant to this Settlement Agreement. The parties agree that PSCR costs for each month from January 1, 1991 to the effective date of the Step 1 increase will be calculated so that the PSCR-related effects of Rockport 2 are excluded in the same manner that they were excluded by the Commission's order in Case No. U-9458.

12. The PSCR-related effects of Rockport 2 should not be included in I&M's 1990 PSCR reconciliation. The parties agree that the calculation of the PSCR-related effects of Rockport 2 shall be made consistent with the methodology used in the Commission's order in Case No. U-9458. The parties further agree that if I&M experiences an underrecovery in its power supply

costs for 1990 greater than $500,000, I&M will propose in its Application for a 1990 PSCR reconciliation that the requested surcharge be collected from I&M's Michigan ratepayers over a period of not less than six (6) months.

13. The rates incorporated in the revised tariff sheets included in Exhibits A and B are intended to provide I&M with a total annual jurisdictional revenue increase of $10,400,000 to be made effective in two steps as described in Paragraphs 3 and 4. The revenue calculations reflecting current and proposed rates are shown on Exhibit D attached hereto. The parties recommend that the Commission approve the revised tariff sheets attached as Exhibits A and B.

14. I&M will file, within six (6) months of the date of a final order approving this Settlement Agreement, an application with the Commission requesting all requisite approvals related to a merger of Michigan Power Company (MPCo), an operating company affiliate of I&M, into I&M. The parties to this Settlement Agreement agree to not oppose the following requests by I&M in such application which are conditions precedent to the merger of MPCo into I&M:

a. The initial establishment of two rate zones, using then-existing base rates, in the service territory of the merged entity, one for MPCo's current service territory and one for I&M's current service territory.

b. The continued recovery in the rates of the MPCo rate zone of all costs deferred as a result of the phasing into rates of Rockport Plant Unit No. 1 (Rockport 1), as ordered by the Federal Energy Regulation Commission in Docket Nos. ER84-587-000 and ER88-30-000, until all such costs are fully amortized.

c. Authority for I&M to continue related accounting to recognize the phase-in of Rockport 1 with respect to the MPCo rate zone.

The parties recognize that the merger of MPCo into I&M can be consummated only after all appropriate federal and state regulation approvals have been granted, which I&M agrees to promptly seek.

15. This Settlement Agreement is intended for final disposition of this proceeding, and the parties hereto join in respectfully requesting the Commission to grant prompt approval of the same. The Staff certifies that this Settlement Agreement is reasonable and in the public interest. Each party agrees not to appeal, challenge or contest the approvals granted by the Commission in this case if they are the result of an order of the Commission in this proceeding, accepting and approving this Settlement Agreement without modification. If the Commission does not accept the Settlement Agreement without modification, the Settlement Agreement shall be withdrawn and shall not constitute any part of the record in this proceeding or be used for any other purposes whatsoever.

16. This Settlement Agreement has been made for the sole and express purpose of reaching a compromise among the positions of the parties to this proceeding. All offers of settlement and discussion relating thereto are and shall be privileged. The Settlement Agreement and the Commission order approving same shall not be used as precedent or in any other manner, nor be admissible, for any other purpose in connection with this proceeding or any other judicial or administrative proceeding, except for the purpose of enforcing this Settlement Agreement.

17. The parties join in requesting that the Commission act expeditiously in evaluating this Settlement Agreement and issuing a final order so that the Step One increase agreed to herein can become effective on April 1, 1991.

18. The parties hereto agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281; MSA 3.560(181)).

INDIANA MICHIGAN POWER COMPANY

Dated: Jan 18, 1991

By Daniel J. Demlow
Daniel J. Demlow (P-12666)
Honigman Miller Schwartz and Cohn
Its Attorneys

MICHIGAN PUBLIC SERVICE COMMISSION

Dated: Jan 18, 1991

By Tonatzin M Alfaro Garcia
Philip J. Rosewarne (P-19651)
Tonatzin M. Alfaro Garcia (P-36542)
Assistant Attorneys General
Attorney for Staff

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

Dated: 18 January, 1991

By Nancy L. Lukey
Nancy L. Lukey (P-28954)
Hill Lewis
Its Attorneys

WHIRLPOOL CORPORATION AND SOUTHERN MICHIGAN COLD STORAGE COMPANY

Dated: Jan 24, 1991

By
Albert Ernst (P-24059)
Dykema Gossett
Its Attorneys

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Case No. U-9656
Exhibit D to
Settlement Agreement

INDIANA MICHIGAN POWER COMPANY
SUMMARY OF ESTIMATED REVENUE –
PRESENT AND PROPOSED RATES

Rate Class	Revenue Present Rates	Revenue Proposed Rates Step One	Step One Dollar Increase	Step One Percentage Increase	Revenue Proposed Rates Step Two	Step Two Dollar Increase	Step Two Percentage Increase
Residential	$37,794,324	$41,089,989	$3,295,665	8.72%	$42,425,414	$1,335,425	3.25%
Commercial	24,781,483	26,941,121	2,159,638	8.72%	27,817,534	876,413	3.25%
Industrial	19,306,147	20,989,643	1,683,496	8.72%	21,671,806	682,163	3.25%
Governmental	2,997,236	3,258,437	261,201	8.72%	3,364,436	105,999	3.25%
Sub-Total	84,879,190	92,279,190	7,400,000	8.72%	95,279,190	3,000,000	3.25%
Estimated PSCR Related Effect*	4,007,796		(4,007,796)	--	--	--	--
Total	$88,886,986	$92,279,190	3,392,204	3.82%	$95,279,190	$3,000,000	3.25%

*This represents the estimated net PSCR effect of Rockport 2, as calculated by I&M pursuant to the November 21, 1990 Opinion and Order in Case No. U-9458. The parties recognize that this is an estimate only and they are not bound by the specific dollar amount shown.

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INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
ATTORNEY GENERAL
DATA REQUEST SET NO. 1
CASE NO. U-20805

DATA REQUEST NO. AG 1-17

Request

Describe any and all actions I&M has taken since the Commission Order in Case No. U-18404 to seek any changes to the UPA.

Response

As discussed in the rebuttal testimony of Company witness Williamson in Case No. U-21189, the UPA is a financing arrangement that has benefited I&M's customers for decades, including providing for favorable debt and equity financing of AEG's share of the investments made in Rockport that serves I&M's customers.

Additionally, see AG 1-11 for additional examples of efforts undertaken to manage costs of generation service at the Rockport Plant that also benefit I&M's customers under the UPA.

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
ATTORNEY GENERAL
DATA REQUEST SET NO. 1
CASE NO. U-20805

DATA REQUEST NO. AG 1-12

Request

Produce any comparisons or other evaluations of the amounts or prices paid for energy and capacity from AEG under the UPA in 2021 to market prices or any other benchmarks.

Response

The Company does not possess the requested information. The UPA is a financing vehicle that assisted in the initial financing of I&M's investment in the Rockport Plant. I&M manages the Rockport Plant, and all investments and O&M expenses are subject to the Commission's review like any other generating plant that I&M owns.

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION
ATTORNEY GENERAL
DATA REQUEST SET NO. 1
CASE NO. U-20805

DATA REQUEST NO. AG 1-13

Request

Is I&M willing to limit recovery of UPA costs to the transfer price benchmark in the same or similar manner as Mr. Stegall describes for ICPA costs? Why or why not?

Response

No. As stated by Company witness Stegall on page 16 of his rebuttal testimony in Case U-20530, "the UPA provided the essential credit support needed to allow I&M to finish Rockport construction and for I&M to retain all of the essential benefits of Rockport ownership - including credit for AEG capacity." Mr. Stegall goes on to state later on that page of rebuttal testimony "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." For example, the fuel purchases discussed by Company witness Ray apply to both I&M's share of the Rockport units as well as the share owned by AEP Generating Company (AEG) and subsequently billed to I&M under the UPA. As a second example, the Company's employees operate the Rockport plant, not AEG's employees.

Preparer
Stegall

Exhibit AG-32

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