FILED
November 4, 2024
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF MODIFICATIONS TO ITS INDUSTRIAL POWER TARIFF – TARIFF I.P.	)))))	**CAUSE NO. 46097**

OFFICIAL EXHIBITS

PETITIONER'S SUBMISSION OF REBUTTAL TESTIMONY OF ALEX E. VAUGHAN

Petitioner Indiana Michigan Power Company (I&M or Company), by counsel, hereby submits the rebuttal testimony and attachments of Alex E. Vaughan.

IURC
PETITIONER'S
EXHIBIT NO. 5
12-20-24 AT
DATE REPORTER

Respectfully submitted,

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
Taft Stettinius & Hollister LLP
One Indiana Square, Suite 3500
Indianapolis, IN 46204-2023
Nyhart Phone: (317) 713-3648
Peabody Phone: (317) 713-3647
Fax: (317) 713-3699
Nyhart Email: tnyhart@taftlaw.com
Peabody Email: jpeabody@taftlaw.com

Tammara D. Avant (Atty. No. 31466-49)
American Electric Power Service Corporation
101 W. Ohio St., Suite 1320
Indianapolis, Indiana 46204
Phone: (317) 508-9262
Email: tdavant@aep.com

Attorneys for Indiana Michigan Power Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 4th day of November. 2024, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

Lorraine Hitz
Adam J. Kashin
Indiana Office Of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
Indianapolis, IN 46204
LHitz@oucc.IN.gov
AKashin@oucc.IN.gov
infomgt@oucc.IN.gov

Jennifer A. Washburn
Citizens Action Coalition
1915 West 18thStreet, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org

Copy to:
Reagan Kurtz
rkurtz@citact.org

Douglas W. Everette
Michael T. Griffiths
Lora L. Manion
DENTONS BINGHAM GREENEBAUM LLP
2700 Market Tower, 10 West Market Street
Indianapolis, Indiana 46204
douglas.everette@dentons.com
michael.griffiths@dentons.com
lora.manion@dentons.com

Joseph P. Rompala
Todd A. Richardson
Emily R. Vlasak
LEWIS & KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282-0003
JRompala@lewis-kappes.com
TRichardson@lewis-kappes.com
EVlasak@lewis-kappes.com

courtesy copy to:
etennant@lewis-kappes.com
atyler@lewis-kappes.com

Liam H. Michener
Carolyn P. Michener
Michener Mullins & Arrington
117 S. Indiana Ave.
Sellersburg, Indiana 47172
lhmichener@mmalawfirm.com
cmichener@mmalawfirm.com

Phillip Casey
Taylor Carpenter
Calfee, Halter & Griswold LLP
3900 Salesforce Tower
111 Monument Circle
Indianapolis, IN 46204
pcasey@calfee.com
tcarpenter@calfee.com

Nikhil Vijaykar2
KEYES & FOX LLP
580 California St. 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com

James C. Holsclaw
Calfee, Halter & Griswold LLP
3900 Salesforce Tower
111 Monument Circle
Indianapolis, IN 46204
Jholsclaw@calfee.com

Mark Valentine
Keyes & Fox LLP
1580 Lincoln St., Ste. 1105
Denver, CO 80203
mvalentine@keyesfox.com

courtesy copy to:

Alicia Zaloga
Keyes & Fox LLP
1155 Kildaire Farm Road, Ste. 202-203
Cary, NC 27511
azaloga@keyesfox.com

Corey Cochran
Keyes & Fox LLP
1155 Kildaire Farm Road, Ste. 202-203
Cary, NC 27511
ccochran@keyesfox.com

Lucas Fykes
Data Center Coalition
lucas@datacentercoalition.org

Aaron Tinjum
Data Center Coalition
aaron@datacentercoalition.org

Kevin Higgins
Energy Strategies, LLC
khiggins@energystrat.com

courtesy copy to:

Shala Coe
scoe@calfee.com

Jeffrey M. Peabody

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
Taft Stettinius & Hollister LLP
One Indiana Square, Suite 3500
Indianapolis, IN 46204-2023
Nyhart Phone: (317) 713-3648
Peabody Phone: (317) 713-3647

Fax: (317) 713-3699
Nyhart Email: tnyhart@taftlaw.com
Peabody Email: jpeabody@taftlaw.com

Tammara D. Avant (Atty. No. 31466-49)
American Electric Power Service Corporation
101 W. Ohio St., Suite 1320
Indianapolis, Indiana 46204
Phone: (317) 508-9262
Email: tdavant@aep.com

Attorneys for Indiana Michigan Power Company

I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

CAUSE NO. 46097

PRE-FILED REBUTTAL TESTIMONY

OF

ALEX E. VAUGHAN

Content

REBUTTAL TESTIMONY OF ALEX E. VAUGHAN
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction

Q1. Please state your name and business address.

My name is Alex E. Vaughan and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q2. By whom are you employed and in what capacity?

I am employed by American Electric Power Service Corporation (AEPSC) as Managing Director- Regulated Pricing Generation & Fuel Strategy. AEPSC is a wholly-owned subsidiary of American Electric Power (AEP), the parent company of I&M.

Q3. Briefly describe your educational background and professional experience.

I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later became the PJM Settlements Lead Analyst, and in that role I was responsible for reconciling AEP's settlement of its activities in PJM market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to Director of Regulated Renewables and Pricing, at which time oversight of regulated renewable and fuel filings across the AEP operating Companies was added to my responsibilities. I assumed my current position in August of 2024.

Q4. Please describe your current responsibilities.

I am responsible for assisting I&M and the other AEP electric utility operating companies in the preparation of their regulatory filings before this and other Commissions under whose jurisdiction these companies provide electric service. My responsibilities include the oversight of cost of service analyses, rate design, special contracts, energy supply costs and new generation resource approvals for the AEP System operating companies.

Q5. Have you previously testified before any regulatory commissions?

Yes. I have presented testimony on behalf of AEP operating companies in numerous proceedings before the regulatory bodies in Indiana, Michigan, Virginia, West Virginia, Kentucky, Tennessee, and Oklahoma.

Q6. Did you previously file direct testimony in this proceeding?

No.

Q7. Are you sponsoring any attachments or workpapers?

Yes, I am sponsoring the following attachments or workpapers, which were prepared or assembled under my direction or supervision:

- Attachment AEV-1R – Company's Response to Data Center Coalition (DCC) DR 1-7 and 1-8.
- Attachment AEV-2R – Amazon's Supplemental Response to I&M DR 1-6.
- Workpapers AEV-1R and AEV-2R – Workpapers supporting my rebuttal testimony as identified below.

II. Purpose of Rebuttal Testimony

Q8. What is the purpose of your rebuttal testimony in this proceeding?

My rebuttal testimony responds to the cost of service and ratemaking issues raised by the parties to this case, with a focus on the Company's proposed 90% minimum demand charge. I also respond to arguments raised by the parties with respect to cost allocation and the Company's Contract Termination Fee analysis provided by Company witness Williamson in direct testimony.

Q9. If you do not respond to a position addressed in another party's testimony, does that imply I&M's acceptance of that party's position?

No, it does not.

III. Tariff IP Minimum Demand Charge

Q10. Multiple intervenor testimonies question the need for the Company's proposed revision to Tariff IP's minimum billing demand provision.[1] Do you have some overall comments regarding the position of the other parties?

Yes. Company witness Williamson's direct testimony (Q22) explains why revising the minimum billing demand from 60% to 90% for large load customers is a reasonable way to protect I&M and its other customers from the potential volatility and variability associated with large load customers. Both the Indiana Office of Utility Consumer Counselor (OUCC) and Citizens Action Coalition of Indiana, Inc. (CAC) agree with I&M's proposal (and CAC argues it could be even further strengthened).[2] The data center parties (Google, Amazon Data Services, Inc. (Amazon), and DCC), on the other hand, oppose I&M's tariff modification.[3]

[1] See Google witness Farr, pp. 19-20; Amazon witness Loomis, pp. 4, 14; Amazon witness Berry, pp. 23-25; Amazon witness Fradette, pp. 20-27; DCC witness Higgins, pp. 10-16.

[2] OUCC witness Leader, pp. 7-8; CAC witness Inskeep, pp. 30-32.

[3] While the Microsoft Corporation (Microsoft) did not file direct testimony, they are a member of the DCC.

As discussed in greater detail below, their opposition fails to consider the dramatic change in I&M's capacity situation taking place as a result of these large loads coming online, with peak load demand expected to more than double by 2030. Moreover, these parties' arguments reflect a misunderstanding of how rates are designed and would lead to a substantial risk that I&M would under-recover the costs to serve these new customers should they cease operations or fail to operate at their contracted capacity.

Q11. On page 17 of his testimony, Google witness Farr asserts that there is "no substantial basis for support" of the 90% minimum billing demand. Do you agree?

No. The need for and reasonableness of the Company's proposed 90% minimum billing demand can be seen by comparing the Company's historical capacity requirements to serve its load to what it now faces as a result of new large load customers. As shown in Figure AEV-1R below, since the year 2000 the Company's capacity requirements based on its load (peak load demand and generation resources available to meet demand) has been mostly static, averaging 4,282 MW on a Total Company basis and varying year over year by no more than roughly 11%.[4]

[4] See Workpaper AEV-1R, tab 'IM Peaks'. Total Company includes the firm load requirements of I&M's Indiana and Michigan retail customers as well as I&M's long-term full requirements wholesale contracts.

Figure AEV-1R – I&M Historical Peak Demands (Total Company)

I&M Annual Peaks	
Year	**Peak Demand MW**
2000	3,949
2001	4,232
2002	4,303
2003	4,223
2004	4,016
2005	4,193
2006	4,650
2007	4,528
2008	4,264
2009	4,262
2010	4,474
2011	4,837
2012	4,726

I&M Annual Peaks	
Year	**Peak Demand MW**
2013	4,540
2014	4,388
2015	4,398
2016	4,547
2017	4,230
2018	4,369
2019	4,191
2020	3,970
2021	4,011
2022	3,850
2023	3,970
2024	3,932

Over this same period of time, the Company has generally had some level of excess generation capacity, which could be used for off system sales or to support load growth through economic development efforts.[5] Not until recent years (with the resolution of the Rockport Unit 2 sale and lease back arrangement) did the Company find itself in a position of not having some amount of generation length.[6]

The Company's recent efforts to acquire generation resources has focused on replacing the capacity needs associated with the Rockport Unit 2 transition and retirement of Rockport Unit 1 by the end of 2028.[7] In other words, they were made to meet current PJM capacity obligations, not the expected doubling of peak load demand caused by large load customers. Service to these large load

[5] The Company sold excess capacity and energy in the AEP East Pool until it terminated on December 31, 2013. Afterwards the Company was compensated for sales of excess energy and capacity into the wholesale markets of the PJM RTO.

[6] Per the Settlement Agreement approved in Cause No. 45546, Rockport unit 2 could no longer be used to meet Indiana retail customer capacity needs after May 31, 2024.

[7] I&M conducted competitive requests for proposals in 2022 and 2023 and filed for approval of the related resources in Cause Nos. 45868, 45869, 46083, 46085, and 46088.

customers is starting now, and thus the Company needs to acquire additional capacity resources (either contracted or owned) to meet this growing retail demand. Company witness Williamson's rebuttal testimony further discusses the need for substantial new accredited capacity over the next five years. Given the dramatic change in the Company's need for capacity, now is the time to implement tariff provisions that will apply to these new loads, including the updated minimum billing demand term.

Q12. Amazon witness Fradette (p. 26) characterizes the Company's 90% minimum demand proposal as "unprecedented" and states "[n]o other state utility commission has approved such a one-sided minimum billing requirement." How do you respond?

Mr. Fradette's statement is incorrect and based on a mischaracterization of the Company's discovery response. As shown in the Company's response to Google Data Request 2-16 (attached to Mr. Fradette's testimony as Attachment MF-13), I&M stated at that time that it was not aware of any state utility regulatory bodies that had approved tariff revisions matching those proposed by I&M. After reading Mr. Fradette's claim that the 90% minimum demand proposal was "unprecedented", I reviewed publicly available tariffs to see if I could corroborate his claim. I could not. As shown in Figure AEV-2R below, it is not uncommon for vertically integrated utilities (*i.e.*, utilities providing both generation and transmission service) to have minimum demand provisions with demand ratchets in excess of 60%, and in some cases the same or higher than the 90% the Company is proposing.

Figure AEV-2R – Minimum Demand Provision Examples from Other Vertically-Integrated Electric Utilities

Company	State	Tariff	Short Description	Highest Demand Ratchet (%) Included in Minimum Demand Provision
Georgia Power	GA	Schedule Power and Light Large (PLL-17)	Demand of 500 kW or more	95%
Alabama Power	AL	Rate High Load Factor Industrial Power	Demand of 3,000 kW or more and annual load factor of 90% or more	90%
Duke	NC	Schedule High Load Factor (HLF)	Demand of 1,000 kW or more	90%
Evergy (Kansas Central)	KS	Schedule Industrial and Large Power Service (ILP)	Demand of 25,000 kW or more	85%
Arizona Public Service	AZ	Schedule Extra Large General Service (E-34)	Demand of 3,000 kW or more	80%
Entergy	LA	Schedule Large Power High Load Factor Service (LPHLF-G)	Demand of 200,000 kW or more	80%
Oklahoma Gas & Electric	OK	Schedule Large Power and Light Standard (LPL-1)	Load Factor of 70% or greater and a minimum annual of 150,000,000 kWh	80%
Dominion Energy	VA	Schedule Large General Service Market-Based Rate (MBR) (Experimental)	Demand of 5,000 kW or more	75%
Entergy	TX	Schedule Large Industrial Power Service (LIPS)	Demand of 2,500 kW or more	75%
Minnesota Power	MN	Schedule Large Light and Power Service	Demand under 50,000 kW	75%

Many of the rate structures associated with these higher minimum demand provisions are also what is generally described as "Demand, Energy, Customer" (DEC) tariffs, where the demand costs are recovered almost exclusively through the demand charges. Conversely, the Company's existing, approved Tariff IP rate recovers a material amount of demand costs through the volumetric energy charge. While the Company does not propose to modify its existing rate design in this case, it is important to recognize this difference when comparing I&M's Tariff IP to other tariff provisions.

Q13. On pages 11-12 of his testimony, DCC witness Higgins describes his view of how a minimum demand charge works and suggests there is no need to increase the minimum billing demand for Tariff IP. Are there any aspects of the Tariff IP rate design that Mr. Higgins overlooks?

Yes. More specifically, the Tariff IP structure contains an hours use blocked energy charge where the first block (first 440 kWh per kW) energy charge includes roughly 44% of the allocated production demand costs for the IP Transmission level rates. Because a material amount of the production demand costs is being collected in an energy charge, this means the effective minimum demand being proposed by the Company is actually much lower than 90%. From a production demand cost perspective, the proposed 90% level equates to an approximate 62% minimum demand charge in application.[8] The hours use blocked energy design of Tariff IP is meant to accommodate industrial loads of varying load factors while not over-burdening lower load factor customers as a straight DEC rate design would. The Company takes this approach in rate design due to the relatively high production demand costs that result from I&M's Cook nuclear facility, which also provides relatively low-cost energy supply.

Q14. Were you able to compare I&M's proposed tariff modifications to the way in which the data center companies receive electric service at their current data centers?

No, not in a meaningful way. In discovery, the Company asked Amazon, Google, and Microsoft to provide information related to their ten largest data centers operating in the United States, including information related to the contract term, whether their load was subject to billing on tariff rates, and whether service was subject to a contract termination fee. As discussed by Mr. Williamson in his rebuttal, all three parties initially objected to producing this

[8] See I&M's response to DCC DR 1-7 and 1-8, included as Attachment AEV-1R to my testimony.

information.[9] This made it challenging to fully assess and respond to the positions taken by the data center companies. That said, Amazon did finally supplement its discovery to state Amazon has several loads that are subject to minimum demand provisions up to 75% and contract terms up to 10 years.[10] While this limited information was not sufficient to perform an apples-to-apples comparison of the minimum demand provisions, it does support the reasonableness of I&M's proposal. This is especially the case when one views I&M's proposal in light of the other vertically-integrated utility tariffs currently in place. Moreover, for the reasons explained above, it is possible I&M's minimum demand charges are effectively even lower as a result of how much fixed production costs are included in I&M's block one energy charge. This further underscores the reasonableness of I&M's proposed increase in the minimum billing demand.

Q15. Amazon witness Berry recommends (p. 25) that no change be made to the minimum billing demand term "[b]ased on the lack of any I&M evidence that large loads would operate at different levels under a 60% or 90% demand charge". She goes on to state (p. 25) "it is not clear given the actual expected load profile of large load customers, how much a 90% demand charge will actually reduce Company risk." Please respond.

As an initial matter, so long as a large load customer actually meets its contracted capacity each month, regardless of the load factor it actually achieves, the customer should be indifferent to the proposed change in minimum billing demand as it would have no impact on their rates and charges. While I&M hopes the new large load customers will meet the forecasted usage

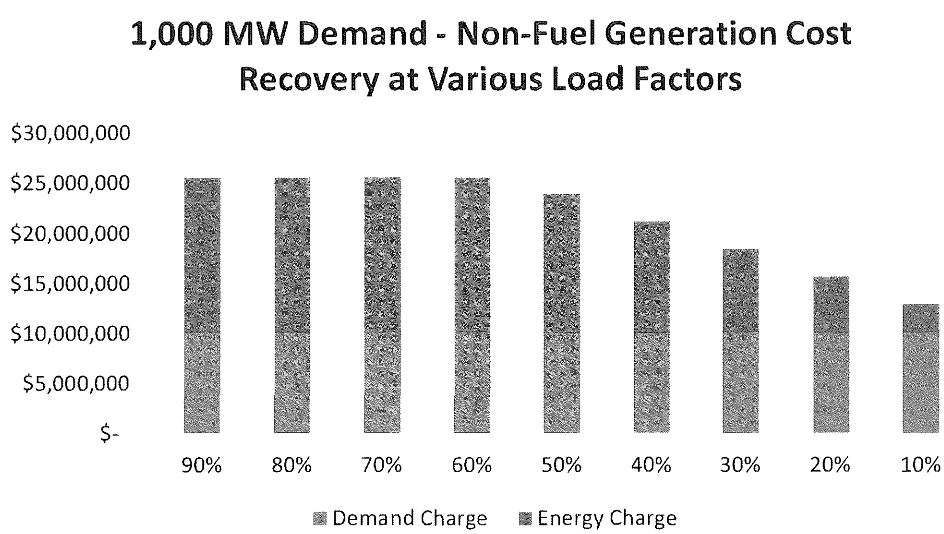
[9] See Company witness Williamson's rebuttal Attachments AJW-2R (Amazon's response to I&M DR 2-10); Attachment AJW-3R (Google's response to I&M DR 2-1); and Attachment AJW-4R (Microsoft's response to I&M DR 2-1).

[10] See my Attachment AEV-2R (Amazon's Supplemental Response to I&M DR 1-6).

and load factors they have provided to the Company, we must also reasonably plan for the alternative.

Witness Berry's testimony does not reasonably reflect the economic rationale for why I&M proposes a 90% minimum billing demand charge. This can be shown through an example of a new large load customer. Let us assume the new customer joins I&M's system with a contract capacity of 1,000 MW. Assuming the hypothetical large load customer in this example achieves the contract demand level for which it has contractually committed to, Figure AEV-3R below shows the level of non-fuel generation cost recovery, using currently approved base rates, that is achieved in total and by the demand and energy charges in the current Tariff IP, including the current 60% minimum billing demand provision.

<u>Figure AEV-3R – Non-Fuel Generation Cost Recovery Examples</u>

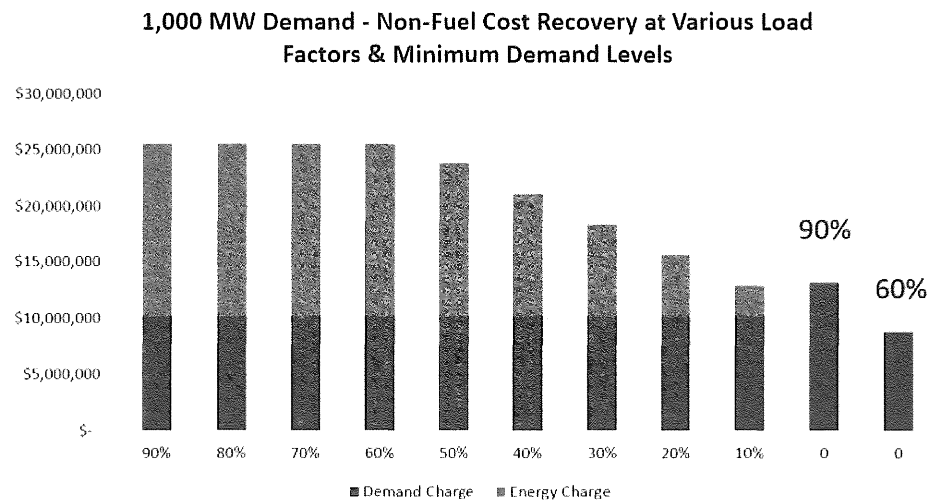


As shown in Figure AEV-3R, the amount of non-fuel cost recovery is highly dependent upon the load's energy usage, and there is a risk of under-recovery as a Tariff IP customer's load factor decreases. Contrary to witness Berry's assertions, this data shows the importance of increasing the minimum billing demand provision to safeguard against a scenario where the large load customer's contracted load does not materialize or the large load customer ceases operations. In that scenario, the expected energy usage will not exist at the level forecasted or at all. As a result, the Tariff IP energy charge will not recover the "demand costs" the energy charge is designed to recover. In this scenario, the non-fuel generation cost recovery would result from only the minimum demand charge that is the subject of debate by the parties in this proceeding. Stated differently, the increase in the minimum billing demand charge is less about ensuring a large load customer meets its expected load factor of 90+% and more about protecting against the scenario where the large load customer does not achieve the peak load they provided to the Company.

Q16. Can you further elaborate on how the Company's proposed 90% minimum billing demand provision protects the Company and its other customers in the event a large load customer ceases operation?

Yes. Figure AEV-4R is the same non-fuel cost recovery analysis as shown in Figure AEV-3R, but modified to show the non-fuel generation cost recovery that would be achieved under the current 60% and proposed 90% minimum demand levels if the customer were to cease operations (*i.e.*, operate at a zero load factor).

<u>Figure AEV-4R – Non-Fuel Cost Recovery at 90% vs. 60% Minimum Demand</u>



The two bars at the far right of Figure AEV-4R illustrate this impact. More specifically, this analysis shows that if a large load customer ceases operation, the Company faces significant under-recovery of its non-fuel generation costs under the existing 60% minimum demand billing provision. Increasing the minimum billing demand to 90% for large load customers is a reasonable step towards safeguarding the Company and its other customers from this risk. Figure AEV-4R further shows the reasonableness of I&M's proposal as it illustrates that, in the case of a large load customer who ceases operations entirely, I&M's non-fuel cost recovery would still be limited to roughly the equivalent of a customer operating at a 10% load factor under I&M's existing Tariff IP structure.

Regardless of the parties' various issues with the Company's minimum demand level increase,[11] the resulting non-fuel generation cost recovery produced by their alternatives is a major factor that the Commission should take into consideration in deciding what level of protections should be in place for existing

[11] See Google witness Farr, pp. 19-20; Amazon witness Loomis, pp. 4, 14; Amazon witness Berry, pp. 23-25; Amazon witness Fradette, pp. 20-27; DCC witness Higgins, pp. 10-16.

customers. As shown above, this is an important safeguard should usage not materialize and adverse scenarios play out with one or more of the new large loads that would be subject to the proposed new terms of Tariff IP.

Q17. On page 19 of his testimony, Google witness Farr claims I&M has "provided no analytical evidence" supporting the 90% minimum billing demand charge. What is the Company's current average embedded fixed cost of its generation resources and what equivalent level would be produced by 60% and 90% minimum demand levels?

Based on the Company's current resource mix, the Company's average embedded fixed cost of generation capacity is roughly $690/MW-day.[12] The equivalent levels of non-fuel generation cost recovery under the 90% and 60% minimum demand levels are $366/MW-day and $244/MW-day respectively.[13] As the Company adds a significant amount of generation capacity to serve these new large loads in the coming years, it is not unreasonable to assume that the average rates in Tariff IP will reduce over time as the incremental cost of generation resources and increased billing units are figured into the ratemaking equation. While Amazon witness Fradette (p. 36) seems to suggest this potential benefit cuts against the need for a 90% minimum billing demand, I disagree. Rather, this dynamic is another reason to increase the current 60% minimum demand level because lower minimum demand charges provide less protection to existing customers in the future. Regardless of whether future retail rates for service go up or down, the higher minimum demand charge remains important to increase the level of confidence that large load customers will reasonably contribute to the fixed costs I&M incurs to provide service and

---

[12] This information was provided to the parties in discovery and included with Amazon witness Fradette's testimony in his Attachment MF-9.

[13] See Workpaper AEV-1R, tab 'IP Billing Details', row 77.

mitigate the adverse impacts that would otherwise occur to I&M's other customers.

Q18. Does the Company's proposed increase to Tariff IP's minimum demand clause provide the Company with an incentive to over-invest in utility owned resources as Amazon witness Fradette alleges (p. 9)?

No, it certainly does not. The minimum charge is based on the allocated cost of service to the class in question, regardless of whether the underlying utility infrastructure providing service is owned by the Company or contracted for from a third party. It is in no way an incentive for the Company to "over-invest" but rather it is a way to protect existing customers and balance the future cost responsibility between new and existing customers should a large load customer in the future cause some amount of stranded costs. The proposed 90% minimum demand clause and other Tariff IP modifications proposed by the Company do not relieve the Company of its obligation to act prudently when planning its system and serving its customers as discussed by Company witness Baker in his rebuttal testimony.

Q19. Does the Commission need to wait for a general rate case proceeding to address the Company's proposed Tariff IP modifications, particularly the 90% minimum demand provision, as Amazon witness Loomis claims at page 9 of his direct testimony?

No, not from a cost of service or ratemaking perspective. Again, from a billing standpoint, large load customers will not be impacted from I&M's proposed tariff modifications if their operations meet the levels they have represented to the Company. Further, the large load customers that would be subject to the new provisions have not yet begun taking service from the Company. Because service will commence soon and ramp up thereafter, now is the time for the Commission to establish the tariff provisions these customers will be subject to when they begin taking service. Continuity in rates is a fundamental ratemaking principle; to not address the clear issues the Company has raised with the new large load customers and the future impacts they will have on the Company's system until sometime after they have begun taking service would be problematic at best. It is more difficult and controversial to change rate structures and tariff provisions after a harm has been done or a subsidy paid to or by a class of customers. The Company's proactive approach is the most practical solution for all parties involved.

Q20. Please respond to Amazon witness Berry's statement (p. 22) that "the amounts paid by large load customers for local transmission costs would, like generation, go to reducing rates for other customers and represent an amount foregone by new large load customers by paying the average system cost instead of the incremental cost to serve them."

Amazon witness Berry's discussion mischaracterizes how electric loads are served and costs are caused. First, witness Berry incorrectly assumes the "incremental" transmission cost to serve these large loads is isolated to the infrastructure costs needed to connect them to transmission system. This is incorrect and is counter to the foundational ratemaking concept of cost causation. A portion of the zonal transmission revenue requirement associated with the system that will serve I&M's peak load will be reallocated based on the coincident peak loads of the load serving entities within the zone.[14] The actual incremental zonal transmission cost increase that the Indiana retail jurisdiction would receive from an increase in peak demand of 4,000 MW would be closer to $431 million annually, rather than the $83.9 million referenced in witness Berry's testimony.[15]

[14] 1 CP allocation of zonal revenue requirement between the AEP LSEs and non-AEP LSEs in the zone, then a 12CP allocation of costs between the AEP affiliated LSEs per the FERC approved AEP Transmission Agreement.

[15] Based upon current zonal revenue requirement and FERC-approved cost allocation methodology. See Workpaper AEV-2R, tab 'IM 4GW', line 13.

Additionally, it is incorrect to assume, as witness Berry does, that the only costs to serve new large load customers are the truly incremental system costs. These large, high load factor loads will be utilizing the existing, robust zonal transmission system and the Company's entire generation resource portfolio (existing assets plus incremental) and as such should share in the cost responsibility for the costs to serve them. Those costs will be a mix of existing system embedded costs and incremental costs. As discussed by Company witness Baker in his rebuttal testimony, as a result of this load growth I&M will need to continue to invest in the transmission system in order to ensure a safe and reliable grid and allow for future economic development expansion in its service area. While it is possible from a ratemaking perspective that, through the combination of additional resources to the Company's system (and their associated costs) and increased revenues from these new loads, average rates are lower in the future for all customers, this should not be viewed as "an amount foregone by new large load customers". Rather, it is a potential positive outcome for all of the Company's Indiana customers.

Q21. DCC witness Higgins (pp. 13-14) discusses the potential market value of capacity not used by a large load customer and suggests this supports a "hold-harmless" minimum demand charge of around 62% and that it could reasonably be set at 70%. How do you respond?

I disagree with Mr. Higgins' conclusion. First, I would note Mr. Higgins' analysis depends on an incredibly volatile year-to-year capacity market clearing price. The example he cites is the highest ever clearing price for the Company's locational deliverability area ($269.92 per MW-day). Just one delivery year earlier, the clearing price was $28.92 per MW-day, or roughly one-tenth the value used by Mr. Higgins. Second, he makes no recognition of the potential liquidation issues that the Company would experience depending on the timing of a load reduction by a customer, as discussed in more detail by Company witness Williamson. Lastly, as also discussed by Mr. Williamson in his rebuttal testimony, the Company has indicated it would support a process that would allow I&M to make a filing with the Commission to address the permanent closure of a large load customer, including the ongoing ratemaking and accounting and the steps I&M is taking to manage the excess capacity.

Q22. Regarding transmission cost allocation, DCC witness Higgins (pp. 15-16) brings up the fact that other load serving entities in the AEP Zone are anticipating large amounts of load growth and that this might affect the allocation of AEP East transmission revenue requirement to I&M. How do you respond?

Witness Higgins is correct that load growth is anticipated for other load serving entities in the AEP Zone. This does not, however, change the need for the protections set forth in I&M's modified terms and conditions. AEP Ohio has publicly discussed upwards of 5,000 MW of load growth over a similar period of time as I&M is expecting to experience its large near-term growth. Using the same analysis that identified $431 million in incremental transmission costs to the Indiana retail jurisdiction discussed above, but also accounting for 5,000 MW of load growth elsewhere in the zone, still results in roughly $294 million of incremental zonal transmission expense allocations to I&M's Indiana retail jurisdiction.[16]

Q23. Please respond to Amazon witness Berry's assertion (pp. 22-25), and that of DCC witness Higgins (pp. 14-16), that only a 60% minimum demand level is needed for transmission charges to adequately protect customers.

Because, as I discussed earlier, these customers' load additions will cause a reallocation of the existing total zonal transmission revenue requirement per the FERC-approved cost allocation methods, a 60% minimum demand level is not sufficient to protect existing customers. Using the same 4,000 MW peak addition as earlier, I have estimated that an 88% minimum demand for the

[16] See Workpaper AEV-2R, tab 'IM 4GW Ohio Scenario', line 13.

transmission charges collected through the PJM/OSS Rider represents the breakeven point where other customers should be indifferent from a transmission cost recovery standpoint.[17] It should be noted that this analysis assumes no incremental investments in transmission infrastructure, which is a conservative assumption as Company witness Baker discusses the expected levels of incremental transmission investment to be potentially significant.

IV. Special Contract

Q24. Multiple parties raise the issue of providing service through special contracts.[18] How do you respond?

Company witness Williamson addresses this issue based on his experience exploring this topic with the large load customers represented in this proceeding. In my experience with this issue across the AEP system Operating Companies, special contracts are generally warranted and appropriate for the following reasons:

1. The customer's usage characteristics are such that they do not fit with the otherwise applicable standard tariff offering and a special contract rate structure can provide *both* the customer and the Company's other customers with cost of service and or rate benefits.
    a. Example: A primarily off-peak load can operate in a way that causes very low amounts of incremental system costs but the standard rate structure produces a very high rate realization.
2. The customer has operational needs that are not contemplated or addressed in the Company's standard tariffs.
    a. Example: A Company's tariff book doesn't already address demand response offerings, standby service for cogeneration needs, renewable/sustainability requirements, and other unique

[17] See Workpaper AEV-2R, tab 'IM 4GW', line 21.

[18] *See* Farr, pp. 4, 23-28; Higgins, pp. 4, 9, 21-22; Fradette, pp. 32-33; Loomis, pp. 5-6.

operational needs.

3. Nationally/Internationally price competitive economic development opportunities that the Operating Company has existing assets which can provide service to and is viewed as a high value economic development prospect.
   a. Example: A prospective load is shopping its new production facility in many states and several countries, the load brings thousands of high-wage direct jobs with it, and the Company can provide all or most of the load's requirements with existing system assets.

In my experience, a customer simply wanting to receive service through a special contract so that it can negotiate its own unique deal is not appropriate, warranted by cost-of-service considerations, or administratively efficient for the utility and Commission in question. In this proceeding the Company is proposing enhancements to its standard Tariff IP for certain large loads that would establish how basic requirements electric service would be provided to them. Beyond that, the Company has multiple Commission approved demand response and renewable tariff offerings that these customers can avail themselves of if they so choose to. In my experience thus far with the specific parties to this case, the new loads do not warrant special contracts for basic requirements electric service.

Q25. Please respond to Amazon witness Berry's testimony at pages 12-13 regarding why the Company did not propose a new tariff class for large load customers.

As an initial matter, I would note that these large load customers' characteristics are not the reason for the Company's proposed refinements to the Tariff IP terms and conditions. Rather, it is their impact in aggregate on the Company's total system as I discussed earlier in my testimony. That said, the Tariff IP rate design can accommodate a range of different customers and operational characteristics, including large load customers. As I demonstrated above in Figure AEV-2R, at a wide range of load factors the blocked energy rate design of Tariff IP will produce consistent and reasonable levels of non-fuel revenue contribution based on the system costs allocated to the Tariff IP class. There is nothing unique about the operating characteristics of the prospective large load customers that will take service under the Tariff IP other than the fact that they are large peak demands. That difference does not warrant the creation of a new tariff class.

More significantly, witness Berry's discussion is silent on the benefits that large load customers will receive in the cost allocation process by being part of a larger, more diverse class of customers. They will benefit from the varying load factors and coincidence factors of the other customers within the class. If the Company were to create a new class for these prospective large, high load factor, uninterruptible customers it would certainly produce the highest unitized cost of any class in the allocation process. I&M's approach to modify Tariff IP's terms and conditions for large load customers, rather than create a new tariff, benefits both the large load customers and I&M's remaining customers. It is also consistent with the way in which these customers will be served, which is through a "slice of system" approach as discussed in greater detail by Company witness Williamson.

V. Direct Assignment and Cost Allocation Arguments

Q26. OUCC witness Kelley (p. 14) states that the demand from large load customers will require new generation and transmission investment and that "all construction and financing costs for these assets – and retirement costs if applicable – should be directed to these large load customers, since they will be the cost-causers." He goes on to state "[c]onsistent with the 'user pays' paradigm, the large load customers must also be accountable for increased maintenance costs due to additional pressures on transmission systems." Please respond.

I agree with Mr. Kelley that the addition of these new large load customers creates new risks and challenges for I&M and its other customers. I also agree that it is important that sufficient safeguards be in place to protect I&M and its other customers from potential adverse consequences should one or more of these customers cease operations or otherwise leave I&M's system. That is why I&M has proposed to modify Tariff IP's terms and conditions in this case.

That said, I am concerned with Mr. Kelley's testimony to the extent it advocates for a departure from the traditional ratemaking approach in Indiana, which recognizes that all customers benefit from the system as a whole, and which generally sets basic rates and charges based on the cost of operating the utility's entire system. As I discuss in my rebuttal testimony, including the large load customers in the Tariff IP class (with I&M's proposed modifications to terms and conditions of service) ensures that these customers benefit from participating in a larger, more diverse class of customers while also ensuring that a reasonable level of system costs are allocated to them. These load additions will not be served by just the incremental resource additions; they will be served by the Company's system as a whole. It is important to recognize this fact in the cost allocation and ratemaking process. With the proper safeguards in place, all customers can benefit from the traditional ratemaking approach and the potential for downward pressure on average rates arising from these loads through said approach.

Q27. CAC witness Inskeep (p. 36) expresses concerns that placing large load customers with existing customers "could create significant cross-subsidization concerns, raising costs for current I&M customers." Please respond.

First, I disagree with Mr. Inskeep's statement (p. 35, line 16) that the Company's existing customers have "paid for" the Company's existing assets. Customers pay for service, not for individual components of the Company's contracted-for and owned assets. Second, I disagree with his contention that because the hypothetical resource installed prices in the Company's current IRP have gone up since the 2021 IRP, that the resulting cost of service will necessarily be greater than the Company's current cost of service.[19] Rather, one would need to also know the fuel costs, estimated capacity factors, operating expense profile, potential tax incentives, renewable energy certificate production, *etc.* to draw his conclusion that "[l]umping new large load customers with existing customers could create significant cross subsidization concerns, raising costs for current I&M customers." It is also possible that average rates will remain the same or go down for all customers in this process, but no one will know for sure until the Company fills out the resource portfolio needed to serve its growing customer load obligations in the future. That is why the Company has approached this proposal as it has, to put in place reasonable, adequate safeguards for all customers before embarking on resource acquisition.

Q28. CAC witness Inskeep (p. 36) recommends that "the portion of a new large load customer's load in excess of 150 MW be 'firewalled' from existing ratepayers with respect to the cost allocation and cost recovery of generation costs." Please respond.

As with OUCC witness Kelley's testimony, I am concerned that Mr. Inskeep's proposal deviates from traditional ratemaking methodologies and is outside the scope of this proceeding. To the extent the CAC or other parties wish to propose alternative cost allocation approaches, the appropriate place to do so is in the context of a rate case where the Company is proposing a change in the overall level of its rates.

While I believe Mr. Inskeep's concerns are better addressed in a subsequent rate case after the Company has added some or all of the resources needed to serve the load additions, I will note that there can be benefits to setting base

[19] CAC witness Inskeep, p. 36, line 2, I&M's IRP Resource Cost Assumptions (Overnight Cost in First Year Available).

rates using average system costs, rather than directly assigning costs as Mr. Inskeep recommends. In an earlier proceeding to consider federal PURPA standards, the Commission noted:

> In this jurisdiction the revenue requirements of the electric utility are determined on the basis of average imbedded costs... There are many arguments in favor of the use of fully allocated average imbedded costs as a basis for determining rates. Such costs are determined by a well-defined time period comparable to the time period upon which revenue requirements are determined and will thus prevent or eliminate uncertainty. Average imbedded costs reflect the great influence of existing costs on the overall revenue requirement. A proper allocation of average imbedded costs permits recognition of demand cost responsibility associated with off-peak loads and the cost responsibility of variances in load factors and will accurately reflect existing operating characteristics and customer load requirements. In addition, by the use of average imbedded costs, the revenue requirements can be accurately allocated and thus eliminate the need for adjustment to eliminate the "revenue gap" problem.

In re Determination of Proceedings Necessary by the Pub. Serv. Comm'n of Indiana, Cause Nos. 35780-S3, -S4, -S5, and -S6, 1981 WL 698186 at *7 (Ind. Pub. Serv. Comm'n Feb. 5, 1981. I mention this not because I believe cost allocation issues should be addressed in this proceeding, but rather to point out that including the large load customers in I&M's existing Tariff IP (with the modifications proposed by I&M) is consistent with these ratemaking principles.

Q29. On page 13 of his testimony, Google witness Farr states that I&M's proposed tariff modifications "will have an impact on how I&M allocates costs among customer classes, as well as how costs are allocated between jurisdictions." Please respond.

I disagree. I&M's proposal in this case is directed to the terms and conditions of service applicable to large load customers within the Tariff IP class. Cost allocation issues, whether between customer classes or between jurisdictions, are outside the scope of this proceeding. Those issues are properly addressed in the context of a rate case that includes a request for a revenue change that would impact such allocations. More importantly, I&M's proposal in this case does not "box in" or otherwise inhibit the ability of the Commission or parties to address cost allocation issues in a subsequent proceeding.

Q30. Could some of the suggested concepts, such as special contracts, direct assignment, or "firewalling" certain generation assets, have unintended consequences if applied to a regulated utility at scale?

Yes. I am concerned the proposals made by certain parties to directly assign or otherwise "firewall" certain generation costs could, on their own, or in combination, potentially result in cost of service and ratemaking issues for all customers and the Company. Only operations subject to cost-based ratemaking meet the criteria to apply Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, Regulated Operations, which permits the Company to recognize the effects of actions of a regulator as regulatory assets or liabilities in its financial statements and facilitate a process to match expense recognition with corresponding recovery through rates. Loss of the ability to record regulatory assets and liabilities and match the timing of expenses with revenue for all or a part of the Company's operations could result in both rate and earnings volatility as well as related impacts to the financial health of the utility.

VI. Contract Termination Fee

Q31. Amazon Witness Fradette alleges (pages 15-16) that the Company's proposed Contract Termination Fee will result in "a financial windfall" to the Company. How do you respond?

I disagree with Mr. Fradette's assertion. As an initial matter, the term "windfall" to me carries an implication that the Company would see some sort of drastically increased profit level from the operation of the proposed Contract Termination Fee. The Company's proposal is meant to provide reasonable protections for its existing and future customers. Moreover, the Company is a regulated utility, subject to the regulatory constructs of the State of Indiana, including an earnings test mechanism. As Mr. Williamson states in his rebuttal testimony, if the Commission were to approve the proposed Contract Termination Fee, the Company would support a regulatory process that would allow for, among other things, evaluation of the adequacy of the Contract Termination Fee paid to I&M.

Furthermore, Mr. Fradette's Figures MF-1 and MF-2 incorrectly assume that the Company's analysis depicted in Figure AJW-1 in Mr. Williamson's direct testimony is dispatching some sort of variable asset cost against a future market price.[20] The analysis in Figure AJW-1 assumes generic future capacity and energy rates to represent the potential average incremental cost of serving these large loads and compares this cost to various potential future market prices to illustrate the reasonableness and potential risks of a large load customer ceasing its operations after the Company has secured longer term assets to serve the obligation. As discussed by Company witnesses Williamson and Baker, the Company plans to utilize a diverse resource portfolio, which will include 3rd party PPAs, to meet its growing load obligation. Generally speaking, PPAs are take or pay arrangements, so under a low future market price scenario the Company would still be paying for the higher priced energy from such an agreement and selling it at a loss. This assumption is included in the Company's analysis of the reasonableness of the termination fee proposal. As such, I cannot agree with Mr. Fradette's criticism of the proposed Contract Termination Fee.

[20] Fradette, p. 15, lines 18-19.

VII. Conclusion

Q32. What is your recommendation?

The parties' arguments in opposition to I&M's proposed minimum demand billing of 90% for large load customers fail to account for the unprecedented situation facing I&M and its existing customer base. Their criticisms of I&M's proposal are inconsistent with the economic rationale behind the proposed change and fail to account for the rate recovery structure of I&M's Tariff IP. The arguments made by the OUCC, CAC, and Google related to cost allocation and direct assignment of costs are outside the scope of this proceeding and create the risk of unintended consequences if adopted. I&M's proposed modifications to Tariff IP's terms and conditions are reasonable, consistent with sound economic and ratemaking principles, and should be approved by the Commission.

Q33. Does this conclude your pre-filed verified rebuttal testimony?

Yes, it does.

VERIFICATION

I, Alex E. Vaughan, Managing Director of Pricing for American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: November 4, 2024

Alex E. Vaughan

DATA REQUEST NO GOOGLE 2-4

REQUEST
Referencing Attachment AJW-1, page 4 of 5, please describe how I&M will handle exit fee revenue from customers exiting contracts under Tariff I.P.

RESPONSE

In the unique situation this event was to occur, the funds would be used to maintain I&M's financial integrity and rate stability for I&M's other customers. This would be accomplished in phases and the payment received from the exited customer would be recorded as a regulatory liability. During the initial phase following the customer's termination, I&M would amortize the regulatory liability to revenue each month based on the customer's past non-fuel billings. This would provide revenue to offset ongoing costs in I&M's riders and base rates. During this period, I&M would be evaluating the available options to manage its ongoing generation portfolio and develop a plan which it would submit to the Commission for review and approval. The Commission's order in such a filing would determine the next phase of how such a payment would be handled going forward.

10. Subject to and without waiver of the foregoing objections, the following Responses constitute the corporate responses of Amazon and contain information gathered from a variety of sources.

Second Supplemental Response of Amazon Data Services, Inc.
Cause No. 46097

Request 1-6: Please provide a list of all contracts Amazon and/or its affiliates/subsidiaries have executed or seek to execute to procure power from another entity (*e.g.*, utility, independent power producer, generation owner, etc.) within PJM and MISO. For each such contract, please identify:

a. Resource type (*e.g.*, wind, solar, etc.);

b. Counterparty;

c. Location;

d. Contract term;

e. In-service date; and

f. Installed capacity.

<u>Objection</u>: Amazon objects to the request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively sensitive, and/or trade secret. In particular, certain of the requested information is highly competitively sensitive because competitive entities (including I&M) are in the market for generation and/or capacity resources and I&M and Amazon are currently negotiating or may in the future negotiate for such resources. The disclosure of the highly competitively sensitive information to competitive entities (including I&M) would put I&M or Amazon's competitors at an unfair competitive advantage, to the detriment of Amazon. Amazon's internal cost projections for any particular data center and the special terms and conditions of privately negotiated and confidential electricity supply agreements, which themselves are trade secret and highly confidential materials subject to existing confidentiality agreements with third parties, are therefore not subject to disclosure. Additionally, any restricted access confidentiality agreement would require the I&M representatives receiving competitively sensitive information to not be involved in competitive market activities, including contract negotiations with Amazon or other Amazon competitors. Subject to and without waiver of the foregoing objections, Amazon provides the following response.

<u>Supplemental Response</u>: Without waiving the foregoing objection and any general objection, Amazon has consolidated a summary of its overall contracted capacities by utility for US based Amazon owned data centers. Specifically, Amazon has identified its largest 10 examples of contracted capacity by utility in the US, excluding its existing contracts with I&M. Additionally, 5 of the examples provided below are in excess of 1GW.

Location	In Excess of 150MW Under Contract?	Minimum demand for transmission, distribution and generation charge greater than 60% of Contracted Capacity?	Contract Term greater than 10 years?	Contract Description	Utility / Tariff
PJM	Yes	No	No	Customer is served via applicable tariff(s).	AEP Ohio https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/November2024AEPOhioTariffBook.pdf
PJM	Yes	No. See comment.	No	Under the agreements executed to-date required to build infrastructure needed to service the load, a min term of not greater than 10 years and min demand charge was mutually agreed to via negotiations based on the specifics of the project(s). As addressed in initial responses, the monthly minimum demand charge is effectively greater than 60% , but less than or equal to 75%, based on the project specifics. However, this minimum demand obligation is not applicable to all transmission, distribution and generation charges. Instead, it is applicable to transmission related charges.	*Redacted due to competitive intel and the aforementioned Objections.*
PJM	Yes	No. See comment.	No	Customer is served via a Special Contract Rate that is structurally equivalent to published tariff. Modification captured in the SCR are mutually beneficial commercial terms that were accepted by both parties and approved by relevant entities, including state commission if applicable. As addressed in initial responses, there is a monthly minimum demand charge greater than 60% , but less than or equal to 75%. However, this minimum demand obligation is not applicable to all transmission, distribution and generation charges.	**Dominion Energy** https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/market-based-rates/mbr.pdf?la=en&rev=c3256a4894c047e49d0e77c4ad18ffc1&hash=2D9D92D585E332569DD0FDBCDB0C5792
PJM	Yes	No	No	Customer is served via a Special Contract Rate that is structurally equivalent to published tariff. Modification captured in the SCR are mutually beneficial commercial terms that were accepted by both parties and approved by relevant commissions.	**NOVEC** Large Power Dedicated Distribution Service - HV 1 Large Power Dedicated Facilities Contract Service - HV 2

Outside PJM	Yes	No	No	Customer is served via applicable tariff(s) and a Special Contract structure. Tarif includes distribution related charges that is based on the installed capacity of infrastructure. There is no minimum demand related charge that is linked to Contracted Capacity for transmission and generation related charges.	**UEC** https://www.aboutamazon.com/news/aws/data-center-oregon-renewable-energy https://www.umatillaelectric.com/wp-content/uploads/Rate-Schedule-2022-Schedule-6-Final.pdf
Outside PJM	Yes	No	No	Customer is served via applicable tariff(s).	**Pacific Corp** https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/048_Large_General_Service_1_000_KW_and_Over_Delivery_Service.pdf
Outside PJM	Yes	No	No	Customer is served via applicable tariff(s).	**PG&E** https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_B-20.pdf
Outside PJM	No	No	No	Customer is served via applicable tariff(s).	**SVP** https://www.siliconvalleypower.com/home/showpublisheddocument/6250/638399684760530000
Outside PJM	Yes	No	No	Customer is served via applicable tariff(s). Tariff includes a fixed monthly fee that is project specific, independent of Customer's actual metered demand or Contracted Capacity over the term of the contract.	**Georgia Power Company** https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/tariffs/2024/tou-sc-14.pdf

Outside PJM	Yes	Yes. See Comment.	Yes	Customer is served via a Special Contract structure that was enabled via legislation, includes the delivery of carbon free specific generation assets and was mutually negotiated to the benefit of both parties. The minimum demand charge was result of mutual negotiations that are based on the specifics of the overall project(s). As addressed in initial responses, the monthly minimum demand charge is effectively greater than 60% , but less than or equal to 75%. Generically, is it intended to cover transmission, distribution and generation charges.	*Redacted due to competitive intel and the aforementioned Objections.*
PJM	No	No. See comment.	No	Under the agreements executed to-date required to build infrastructure needed to service the load, a min term of not greater than 10 years and min demand charge was mutually agreed to via negotiations based on the specifics of the project(s). As addressed in initial responses, the monthly minimum demand charge is effectively greater than 60% , but less than or equal to 75%, based on the project specifics. However, this minimum demand obligation is not applicable to all transmission, distribution and generation charges. Instead, it is applicable to transmission related charges.	*Redacted due to competitive intel and the aforementioned Objections.*