**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| PJM Interconnection, L.L.C. | Docket No. ER24-843 |
|---|---|

**Protest and Comments of**
**Maryland Office of People's Counsel**

PJM Interconnection, L.L.C. (PJM) seeks the approval of the Federal Energy Regulatory Commission ("FERC" or "the Commission") for its proposed revisions to Schedule 12, Appendices A and C of the PJM Open Access Transmission Tariff (Tariff or OATT) to incorporate cost responsibility assignments for hundreds of baseline upgrade projects included in PJM's most recent update to its Regional Transmission Expansion Plan ("RTEP").[1] Pursuant to Rule 211 of the Commission's Rules of Practice and Procedure,[2] and in accordance with the Commission's January 10, 2024 Combined Notice of Filings #1[3] and the January 11, 2024 Errata Notice Extending Comment Period,[4] Maryland Office of People's Counsel ("Maryland OPC") protests and comments on PJM's proposed cost allocations for a subset of the projects covered in the filing—those selected through PJM's 2022 RTEP Window 3 transmission planning and procurement process (the "Window 3 Projects").[5] As explained further below, and

[1] PJM Interconnection, L.L.C., Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades (Jan. 10, 2024), Docket No. ER24-843, Accession No. 20240110-5117 (PJM Filing).

[2] 18 C.F.R. § 385.211.

[3] Accession No. 20240110-3056.

[4] Accession No. 20240111-3082.

[5] Maryland OPC submitted a motion to intervene in this proceeding on February 8, 2024. *See* Accession No. 20240208-5002.

in the attached affidavit of Ron Nelson, Senior Director at Strategen Consulting, PJM's proposed cost allocations are, for several reasons, unjust and unreasonable and should not be approved.

## SUMMARY

The Window 3 Projects represent an unprecedented expansion of PJM's transmission system—and an enormous burden on ratepayers—carrying a regional price tag in excess of $5 billion in estimated capital expenditures. Of that total, the revenue requirements associated with more than $551 million in capital expenditures—roughly 10% of the total costs—will be charged to locational deliverability areas ("LDAs") serving Maryland ratepayers under the PJM Tariff's generally applicable cost allocation methodology for RTEP reliability projects.[6] On a per kilowatt basis, the burden of these costs is significant on the LDAs serving Maryland ratepayers and approaches that of the LDAs serving Virginia. While significant costs of this load growth are borne by Maryland ratepayers, Maryland LDAs are not expected to experience the same exponential load growth in the next few years as is forecasted for the Dominion LDA.

This is unfair. Mr. Nelson explains in his affidavit that this huge transmission buildout is driven primarily by the anticipated addition of massive new electric needs associated with the construction of data centers in Northern Virginia.[7] As Mr. Nelson further explains, this data center development, in turn, is facilitated and enabled by massive fiscal policy support from Virginia state and local governments.[8] Mr. Nelson explains that PJM predicts dramatic increases

[6] Nelson Affidavit at 10:15-17.

[7] *Id.* at 13:4-5.

[8] *Id.* at 18:11 – 21:12.

in electricity load demand from data centers in the Dominion zone over the next several years, "grow[ing] from approximately 3.5 GW in 2023, to over 15 GW in 2028."[9] In response to this exponential demand growth, PJM initiated a planning process window to solicit solutions for system needs associated with (1) the addition of up to 7,500 MW of new data center load, and (2) the anticipated deactivation of more than 11,000 MW of generation across the PJM footprint.[10]

The Window 3 Projects are the suite of transmission solutions PJM selected through that process. Because PJM has deemed these facilities to be "needed for reliability," the cost of the Window 3 Projects that will operate at or above 500 kV ("Regional Facilities") will be allocated via a hybrid cost allocation methodology under which 50 percent of costs are regionalized on the basis of each transmission owner's annual load-ratio share and the other 50 percent are allocated on the basis of PJM's solution-based distribution factor (DFAX) methodology.[11] For non-Regional Facilities or "Lower Voltage Facilities," costs are allocated entirely using the solution-based DFAX methodology.[12] Under PJM's proposed cost allocations, only approximately 50% of the costs of the Window 3 Projects will be allocated to Virginia ratepayers within the Dominion LDA or Dominion "zone,"[13] despite the need for those projects having been overwhelmingly created by load growth within the Dominion LDA within Virginia.

---

[9] *Id.* at 15:13-14. Mr. Nelson goes on to observe that this load is expected to grow to 25 GW in 2039. *Id.* at 12:15-16.

[10] *Id.* at 6:19 – 7:2. Additional background concerning the PJM RTEP process is provided in Mr. Nelson's affidavit. *See id.* at 6:9-18, 7:9 – 10:7.

[11] PJM Filing at 4-5.

[12] *Id.* at 6, n.17.

[13] *See* Nelson Affidavit at 11 (Figure 1).

Moreover, given the unprecedented and uncertain nature of this expected load growth, there is significant risk that these load increases—or substantial portions of them—may never be realized. As explained by Mr. Nelson, "[n]either the load magnitude nor the timing that it materializes can be projected with confidence given the lack of historical data and experience . . . ."[14] Should actual loads fall short of PJM's projections, Maryland ratepayers may be on the hook to pay for an expensive portfolio of projects that, in reality, were not needed. That risk would be exacerbated if the Commission subsequently awards project developers CWIP and abandoned plant incentives.

These unique circumstances warrant heightened scrutiny of PJM's proposed cost allocations for the Window 3 Projects. As explained further below:

- PJM bears the burden of proof in establishing that its filing is just and reasonable and not unduly discriminatory or preferential.

- PJM failed to carry that burden of proof in its application of its "default" general transmission cost allocation methodologies to allocate the costs of the Window 3 Projects.

- The cost allocation adopted by PJM fails to conform to the governing principle for cost allocation—to align cost allocation with the parties benefitted.

- PJM erred by ignoring Virginia's public policy interventions driving massive data center load growth and failing to treat the Window 3 Projects as multi-driver projects.

Acceptance of PJM's cost allocations will have impacts beyond this proceeding. Under the Tariff, Schedule 12, the allocations in this proceeding will fix the cost responsibility for pre-

[14] *Id.* at 16:5-6.

in-service incentives like CWIP and abandoned plant using current electric loads rather than the anticipated increased electric loads driving the need for the Window 3 Projects. If those incentives are awarded, PJM's filing will result in Maryland ratepayers paying more than their fair share of Window 3 Project costs.

## COMMENTS AND PROTEST

### I. As the applicant in this proceeding, PJM bears the burden of proof to establish that its filing is just and reasonable and not unduly discriminatory or preferential.

PJM makes its filing in this proceeding as an applicant pursuant to section 205 of the Federal Power Act ("FPA"). 16 U.S.C § 824d(e). As such, PJM bears the burden of proof to show that its proposed rate or charge is just and reasonable and not unduly discriminatory or preferential.[15] For the reasons stated below, PJM's filing does not satisfy this requirement. Accordingly, the Commission should reject it, or, in the alternative, determine that it is deficient pending PJM's submission of additional information and an opportunity for interested parties to review and comment on that information.

### II. The Window 3 Projects are a Multi-Driver Project pursuant to the PJM Operating Agreement (OA), Schedule 6, Sec. 1.5.10(h).

The predominant motivation for PJM's Window 3 procurement and the transmission projects selected as part of Window 3 is to address grid reliability "needs" arising from huge

[15] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 181 FERC ¶ 61,219, P 31 (2022) (citing 16 U.S.C. §824d(e) and *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993)); *Panda Stonewall LLC*, 174 FERC ¶ 61,266, P 30 (2021) ("Under section 205 of the FPA, the applicant bears the burden of proof to show that the proposed rate or charge is just and reasonable") (citing 16 U.S.C. § 824d(e)); *Xcel Energy Servs. Inc. v. FERC*, 41 F.4th 548, 551 (D.C. Cir. 2022) ("A utility seeking a rate or rule adjustment under Section 205 bears the burden of showing that its proposal is just and reasonable."); *Emera Me. v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017) ("A utility filing a rate adjustment under Section 205 must show that the adjustment is lawful." (emphasis omitted)).

increases in forecasted electric loads in certain targeted locations.[16] These forecasted load increases are due to the unprecedented, accelerated development of electric, load-intensive data centers located in the geographically targeted area of Northern Virginia within the Dominion LDA, with massive demand increases extending forward to 2027/28 and beyond.[17] This huge, material load growth in Virginia is being fueled by fiscal intervention and support for data center development by Virginia's state and local governments.[18]

PJM's estimate and evaluation of the aggregate capital expenditure in transmission plant entailed by the selected Window 3 transmission projects is similarly massive, well in excess of $5 billion.[19] The purpose of PJM's filing is to allocate the costs of these Window 3 Projects to the respective LDAs within PJM's footprint, with the majority of the costs allocated to electric loads in the PJM footprint other than those in the Dominion LDA, though the Dominion LDA picks up the largest cost allocation borne by a single LDA. This cost allocation, ostensibly following from the application of PJM's tariff for cost allocation of transmission projects included in its RTEP, violates basic principles of proper cost allocation[20] and the provisions of

[16] Nelson Affidavit at 13:3-11.

[17] *Id.* at 13:12-19.

[18] *Id.* at 18:11 – 20:6.

[19] *Id.* at 10:11-13.

[20] *See, e.g., PSEG v. FERC*, 989 F.3d 10, 13 (D.C. Cir. 2021) ("The Commission has long viewed the just–and–reasonable requirement to 'incorporate a 'cost–causation principle.' *Old Dominion Elec. Coop. v. FERC*, 898 F. 3d 1254, 1255 (D.C. Cir. 2018). That 'principle requires costs 'to be allocated to those who cause the costs to be incurred and reap the resulting benefits.' *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014) (quoting *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007))."). FERC's Order No. 1000 requires RTOs, including PJM, to adopt transmission cost allocation methods which satisfy six criteria, the first of which embodies the cost-causation principle by requiring that costs be "allocated in a way that is at least roughly commensurate with benefits." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. Stats. & Regs. ¶ 31,323 P. 622, 76 Fed. Reg. 49,842, at 49,937 (Aug. 11, 2011), *petitions for review denied*, *S.C. Pub. Serv. Auth.*, 762 F.3d 41 (D.C. 2014).

PJM's tariff and operating agreement—by not aligning cost causation (the tightly focused, huge data center load growth) and the responsibility for the cost recovery of the Window 3 Projects that PJM deemed necessary to reliably serve that load growth. This misalignment is particularly problematic here, given the massive, unprecedented scale of the Window 3 Projects. As discussed further below, PJM should have determined that the Window 3 Projects are a Multi-Driver Project, pursuant to OA, Schedule 6, Sec. 5.1.10(h). Use of the Multi-Driver Project cost allocation methodology of the Tariff, Schedule 12, would be a mechanism for better aligning the cost causation and cost responsibility for the W3 Projects.

The misalignment of cost causation and responsibility—and its scale—is particularly problematic for Maryland. Because of its proximity to Virginia, the Maryland LDAs will bear a disproportionate and burdensome share of the cost allocation, as directed pursuant to the PJM filing. Yet, Maryland LDAs will not be experiencing Virginia's load growth and lack the scale and projected increased electric sales to end-users in Virginia to better spread the costs resulting from PJM's proposed allocation of Window 3 Projects' costs.

PJM also indicated that the Window 3 procurement was intended to be responsive to certain factors other than the Virginia data center load—without indicating their relative weight—in defining the "needs" for the W3 procurement, including the pending deactivation of certain power projects, some of which are located in Maryland. Prior to completion and selection of the Window 3 Projects, PJM already proposed entering into reliability must-run ("RMR") arrangements to keep these plants in operation for an extended period and approved the construction of baseline transmission upgrade projects, estimated to entail $785 million in capital expenditures, to address the grid reliability violations resulting from these proposed plant deactivations. [21] PJM allocated the majority of the cost of those upgrades to LDAs in Maryland (the LDAs for Baltimore Gas and Electric ("BGE") and Potomac Electric Power Company ("Pepco"), respectively). Pursuant to PJM's tariff, the costs of the RMR arrangements when finalized will be allocated in the same manner (i.e., predominantly to electric loads in the BGE and PEPCO LDAs).

In this proceeding, PJM does not identify or describe how the projects identified to address pending plant retirements approved in ER23-2612 fall short in addressing the issues arising from resource deactivations, and which PJM asserts need further to be addressed by some un-specified subset of the Window 3 projects.

### A. The data center load growth in Northern Virginia is a result of Virginia's "Public Policy Requirements" and "Public Policy Objectives," as those terms are employed in PJM's governing documents.

As explained in Section III of Mr. Nelson affidavit, the development of data centers in Northern Virginia—and their attendant high level of electric usage—is not due to happenstance. It reflects the combination of underlying industry and economic trends and fifteen years of massive fiscal policy intervention favoring data center development by the Commonwealth of Virginia and its municipal and county governments. For fiscal years 2022–2025 alone, Virginia

[21] *Order on Cost Allocation Report and Tariff Revisions, PJM Interconnection, LLC*, 185 FERC ¶ 61,107 (Nov. 8, 2023). The upgrade filings and the initial allocation of their costs were accepted and approved by FERC in docket ER23-2612

estimates approximately $3.6 billion in tax subsidies have and will be extended to the industry. These incentives are anchored in Virginia law.[22]

Moreover, the out-sized electric load needs of data centers are well known. Data center electric needs are characterized as "dense" and relatively continuous over time when compared with other types of electric usage. While Virginia's state policy incentivizes locating data centers within the Commonwealth, the tight correlation between data center development and electric consumption means that it is essentially also a state policy to promote massive electric infrastructure development to supply data center needs. Given this context, Virginia's ambitious state policies favoring data center development are "Public Policy Objectives" (for convenience here, "PPOs") and "Public Policy Requirements" ("PPRs") (collectively, "PPROs") within the meaning of PJM's governance documents.

PJM's Operating Agreement define these terms as follows:

> "Public Policy Objectives" shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.
>
> "Public Policy Requirements" shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity. [23]

[22] Nelson Affidavit at 19:14-16.

[23] OA, Section 1, Definitions.

These definitions include state level policies that are closely associated with promoting or regulating electric production or usage fit within these definitions. Virginia's state laws and policies favoring data center development are behind the massive increase in forecasted electric loads, which, in turn, primarily drove the "need" for the Window 3 Projects' procurement. Accordingly, the Window 3 Projects the projects are the outcome of Virginia's PPRs and PPOs.[24]

### B. PJM improperly failed to treat the 2022 RTEP Window 3 Transmission Project Procurement as a Multi-Driver Project.

In this context, PJM should have treated the Window 3 Projects as a "Multi-Driver Project" under the provisions of the OA, Schedule 6, Sec. 1.5 and the PJM Open Access Transmission Tariff ("OATT"), Schedule 12. PJM did not do this. The Multi-Driver Project cost allocation methodology, if applied to the Window 3 Projects, would allocate to Virginia the costs of transmission project(s) caused by that state's PPROs.[25]

Instead, PJM approved the Window 3 Projects and their cost allocations as a consolidated set of reliability projects, resulting in the application of PJM's "default" procedure for cost allocation of regional transmission projects. This renders unjust and unreasonable the cost allocations to load of the Window 3 Projects filed by PJM in this docket. Conforming to the PJM OA and tariff, PJM should have considered the Window 3 Projects as a Multi-Driver Project and undertaken the cost allocation of the Window 3 Projects pursuant to the Multi-Driver cost allocation methodology of its Tariff. OATT, Schedule 12.

---

[24] *See* Nelson Affidavit at 21:15 – 22:10.

[25] *See* PJM Operating Agreement, Sched. 6, 1.5.10(e) and (h); PJM OATT, Sched. 12 (b)(xiv).

Provisions for consideration and evaluation of PPROs and their influence on cost allocation of transmission projects included in PJM's RTEP are embedded throughout PJM's governance documents. Thus, the OA requires that Public PPRs and PPOs be evaluated and considered by PJM in the development of PJM's annual RTEP, through which, among other matters, it conducts transmission project procurements and approves transmission "baseline" upgrade projects.[26]

PJM also can accommodate PPROs in its transmission planning through its State Agreement Approach ("SAA") described in OA, Schedule 6, Sec. 1.5.9. Under this provision, states can expressly agree to be responsible for the "allocation of all costs of a proposed transmission expansion or enhancement that addresses state [PPRs] identified or accepted by state(s) in the PJM region."[27] The costs of projects done under the SAA are "recovered from customers in a state(s) in the PJM region that agrees to be responsible for such projects."[28]

---

[26] *See*, Operating Agreement, Schedule 6, Secs. 1.5.1(a) (PJM "may initiate the enhancement and expansion study process to address or consider, where appropriate, requirements or needs arising from . . . [PPOs]."); 1.5.3(d) (PJM consideration of PPOs in studies and analysis; enhancement and expansion studies "shall include" among other matters "[i]dentification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting…. [PPRs]"); 1.5.4(c) (soliciting of information about PPOs); 1.5.6(b) (inclusion of assumptions about PPRs and PPOs through the TEAC and Subregional RTEP Committees and as provided by the Independent State Agencies, with a posting of the PPORs and an explanation of which PPROs were introduced by stakeholders and adopted or not adopted by PJM); 1.5.6(e) (conduct of regular meetings with the Independent State Agency Committee to discuss "other [PPOs]"); 1.5.6(f) (posting of PPRs after completion of studies and analysis); 1.5.8(b) (posting of PPRs used to establish "transmission need information" including "state [PPRs] identified or agreed to by the states in the PJM Region…" and explaining which PPRs "were not selected for further evaluation"); 1.5.8(d) (circulation following closing of a procurement window of "proposals addressing state [PPRs] to the applicable states"); 1.5.8 (e) (consideration of inclusion of projects that would have secondary benefits, such as addressing federal or state PPRs).

[27] PJM Operating Agreement, Sched. 6, Sec. 1.5.9(a).

[28] *Id.*

The PJM OA does not explicitly state how to allocate the cost of RTEP transmission projects caused by a PPRO project "driver" that is not identified during the PJM RTEP stakeholder development process nor agreed to by the state responsible for that PPRO project driver through a SAA. These are the circumstances faced here—proposed baseline transmission projects driven by a state's PPROs, but not associated with a PPRO under either the stakeholder or SAA process. Any reasonable interpretation of the PJM OA and tariff would preclude what is happening here: A state PPRO is "driving" the "need" for transmission projects and spreading the costs across all states within the PJM footprint by neither identifying it for consideration in the PJM stakeholder and planning process nor participating in the SAA. The effect is to reduce the state's full cost responsibility for the projects' cost.

To address this gap in the rules, the OA, Schedule 6, sec. 1.5.10(h) provides, in relevant part, that:

> [PJM] **shall determine** whether a proposal(s) [the transmission projects to be procured by PJM through the RTEP] meets the definition of a Multi-Driver Project by identifying a more efficient or cost effective solution that uses one of the following methods: (i) combining separate solutions that **address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project ("Proportional Multi-Driver Method")**; or (ii) expanding or enhancing a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers ("Incremental Multi-Driver Method"). [Emphasis supplied.]

This provision obligates PJM, as a final backstop, to make a reasonable determination about whether a transmission project approved through its planning process is a Multi-Driver Project. Moreover, it provides the framework PJM must use in making this determination. PJM has not demonstrated that it had a reasonable basis for deciding not to use the Multi-Driver Project process and cost allocation methodology for the Window 3 Projects.

PJM may claim that its independent obligation to determine whether a project is a "multi-driver project" is constrained by the definition of the term in the OA.[29] Yet, the express PJM decision rule for determining a Multi-Driver Project, set forth in OA, Schedule 6, Sec. 1.5.10(h), has three "need" input criteria for establishing the existence of such a project: "reliability, economics and/or public policy." These criteria are provided without reference to and are not constrained by the asserted limiting mention of "SAA initiatives" contained in the OA definition of the term. Accordingly, the OA's Schedule 6, Sec. 1.5.10(h) decision rule should prevail on its own terms. The OATT provision for cost allocation of a Multi-Driver Project uses unconstrained similar language in describing the separate drivers around which the cost allocation is done. This reinforces this conclusion about the proper reading of OA, Schedule 6, sec. 1.5.10(h).[30]

---

[29] "'Multi-Driver Project' shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives." PJM OA, Definitions.

[30] OATT, Schedule 12. (b)(xiv). "Multi-Driver Projects. (A) Assignment of Proportional Multi-Driver Project Costs. The Transmission Provider shall assign cost responsibility for Proportional Multi-Driver Projects in proportion to the relative percentage benefit that each driver of a Proportional Multi-Driver Project addresses, respectively, **reliability violations or operational performance ("reliability"), economic constraints ("economic") and/or Public Policy Requirements ("public policy")…."** (emphasis supplied).

Moreover, to the extent the general definition of the term, multi-driver project, is afforded a constraining effect, so as to displace or override language in the substantive provisions of PJM's governance documents, due to application of the canon or convention for statutory interpretation of *expressio unius est exclusio alterius* (the express mention of one thing, excludes another alternative), that convention or canon of construction is not apt in this context. *See, e.g.*, *Salzburg et. al. v. Schiabbacucchi*, Del. Sup. Ct. C.A. No. 2017-0931 (2020), p. 22, n.77 (deciding a matter under Delaware law; favorably citing to legal commentary to the effect: "that the *expressio unius* canon is '[i]napplicable if statutory purpose or context suggests listing is not comprehensive.'"). OA, Sec. 4.2 (Delaware is governing law of the OA).

As discussed above, the Window 3 Projects primarily address the "need" created by the data center developments in Northern Virginia which are, in major part, the outcome of Virginia's PPROs. The Window 3 projects (the "solutions") "address [in combination] reliability, economics and/or public policy."[31] They "incorporate[ ] separate drivers into one Multi-Driver Project."[32] Accordingly, the Window 3 Projects properly comprise a Multi-Driver Project under the PJM OA and Tariff. PJM's failure to make this determination is not a reasonable application of its Tariff in conducting the cost allocation of the W3 Projects.

## III. PJM's cost allocations hard-wire in cost responsibility for transmission incentives anticipated to be requested by the developers of the Window 3 Projects (*e.g.*, construction work in progress, abandoned plant) based on current electric loads that are likely to be dramatically misaligned with the electric loads benefitted by the Window 3 Projects when the Window 3 Projects go into service in 2028 or later.

As explained in Section IV of Mr. Nelson's Affidavit, under PJM's cost allocation of the W3 Projects, CWIP costs would be allocated using the load-ratio share allocator and the remaining half would be allocated using the DFAX allocator.[33] Thus, 50 percent of the facility's costs would be allocated on a load-ratio share basis that assigns the costs proportionally to the peak load in each zone.[34] For the 2022 RTEP Window 3, this peak load is defined based on 2022 loads.[35] This load-ratio share allocation of costs is then fixed for purposes of CWIP based on PJM's filing in this proceeding until the placement into commercial operation of the Window

[31] OATT, Schedule 12. (b)(xiv).

[32] *Id.*

[33] Nelson Affidavit at 26:3-4.

[34] *Id.* at 26:5-6.

[35] *Id.* at 25:7-8.

3 Projects, anticipated to occur in 2027-2028, during the period CWIP and possibly other transmission incentives, such as abandoned plant if any, will be recovered.[36]

This approach does not follow the governing cost causation/beneficiary pays principles for cost allocation of transmission projects, particularly given the huge and disproportionate increases in electric loads anticipated for the Dominion LDA between now and the date when the Window 3 Projects will go into service.[37]

Maryland OPC is deeply concerned about the misalignment between the cost responsibility and cost causation generally for the Window 3 Projects under PJM's filing. However, this misalignment is exacerbated for CWIP costs.[38] As Mr. Nelson explains in his Affidavit, the peak loads for each LDA in 2022 (which are used to determine the load-ratio share for CWIP costs) are not representative of future peak loads that will emerge as a direct result of the Window 3 Projects.[39] Since many of the Window 3 Projects are being built specifically to accommodate future load growth in Northern Virginia due to data center development, the Window 3 Project CWIP costs should similarly use that future load to allocate costs.[40] The 2022 load-ratio share will significantly change by 2028, when the transmission projects are anticipated to be completed and the new load has surfaced.[41] Thus, continuing with the current CWIP load allocation methodology would not follow the beneficiary pays

---

[36] Tariff, Schedule 12, sec. (b)(iii)(H)(1).

[37] Nelson Affidavit at 27:6-7.

[38] *Id.* at 26:17.

[39] *Id.* at 26:18 –27:1.

[40] *Id.* at 27:1-4.

[41] *Id.* at 27:4-5.

principle.[42] Instead, it would cause non-Virginia ratepayers to pay an excess share of the W3 Project costs during the period when the W3 Projects are in construction that is not commensurate with the benefits received once the projects are completed.[43]

Given the unprecedented scale of and the disproportionate changes in future load growth, the massive transmission investment involved and the relatively long construction period for these transmission projects, proper administration of the tariff requires the following approach: From the initial effective date of the proposed cost allocation until completion of the Window 3 Projects, the future loads forecasted to occur at the time of the in-service date of the W3 Projects should be used for calculation of the load ratio share portion of the PJM cost allocation methodology. Failing to do so renders the tariff unjust and unreasonable in violation of the FPA.

## CONCLUSION

For the reasons stated above and in the accompanying affidavit, PJM's filing does not satisfy its burden of proof and its obligation to demonstrate its compliance with the Tariff under Section 205 of the FPA. Accordingly, the Commission should reject the filing, or, in the alternative, determine that it is deficient pending further satisfactory explanation and resolution by PJM of the filing's deficiencies in response to a deficiency letter informed by the discussion herein.

Respectfully submitted,

[42] *Id.* at 27:6-7.

[43] *Id.* at 27:7-10.

MARYLAND OFFICE OF PEOPLE'S COUNSEL

DAVID S. LAPP
PEOPLE'S COUNSEL

William F. Fields
Deputy People's Counsel

/s/ electronic signature_
Philip L. Sussler, Assistant People's Counsel

Email addresses:
William.fields@maryland.gov
Philip.Sussler@maryland.gov

Office of People's Counsel
State of Maryland
6 St. Paul Street, Suite 2102
Baltimore, Maryland 21202
Tel: (410) 767-8150

February 9, 2024

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing pleading to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated this 9th day of February, 2024.

_/s/ electronic signature_____
Philip L. Sussler

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | |
|---|---|
| PJM Interconnection, L.L.C. | Docket No. ER24-843 |

AFFIDAVIT

OF

RON NELSON

ON BEHALF OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

February 9, 2024

EXHIBIT RN-1: Resume and Curriculum Vitae of Ron Nelson

**AFFIDAVIT OF**
**RON NELSON**

## Introduction

**Q. Please state your name and business address.**

A. My name is Ron Nelson. My business address is Strategen Consulting (“Strategen”), 10265 Rockingham Dr., Suite #100-4061, Sacramento, CA 95827.

**Q. Please describe your professional experience, educational background, and qualifications.**

A. I am currently a Senior Director at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and expertise in regulatory innovation, performance-based regulation, rate design, renewable program development, grid modernization, new grid technologies, and electric vehicles (“EVs”). During my time at Strategen, I have worked with numerous consumer advocates, nongovernmental organizations, utilities, and public service commissions on issues related to cost-of-service modeling, cost allocation, rate design, grid modernization, distributed energy resource valuation and integration, and performance-based regulation.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General’s Office for almost five years, where I led that office’s work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and

Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University, where I also minored in Mathematics. My resume is attached as Exhibit RN-1.

**Q. Have you previously testified in regulatory proceedings?**

A. Yes. I have testified in over 65 proceedings in Colorado, Georgia, Illinois, Indiana, Maine, Maryland, Massachusetts, New Hampshire, North Carolina, Nevada, North Dakota, Michigan, Minnesota, Ohio, Oklahoma, Pennsylvania, South Carolina, Utah, and Vermont. The issues covered in these proceedings include marginal and embedded cost of service studies, revenue apportionment, rate design, load management, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, distributed energy resource ("DER") interconnection, DER compensation, DER integration, DER cost allocation, EV infrastructure investments, pilot frameworks, automated metering infrastructure, prudence review, distribution system planning, capital investment plan review, and smart inverter integration, among other topics.

I also advise the Hawai'i, Colorado, Kentucky, and Connecticut Public Service Commissions, and have supported clients in a Federal Energy Regulatory Commission (FERC) proceeding.

**Q. Have you previously testified before FERC?**

A. No.

**Q. On whose behalf are you appearing?**

A. I am presenting testimony on behalf of the Office of People's Counsel of Maryland.

**Q. Have you prepared exhibits to accompany your testimony?**

A. Yes. Exhibit RN-1 provides my resume.

**I. Summary and Recommendations**

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

A. On January 10, 2024, PJM submitted amendments to Tariff, Schedule 12-Appendices A and C to incorporate cost responsibility assignments for 215 baseline upgrades in the recent update to the Regional Transmission Expansion Plan ("RTEP") approved by the PJM Board of Managers ("PJM Board") on December 11, 2023. The primary driver the 2022 RTEP Window 3 ("W3") upgrades is load growth in Virginia due to data center development. In my testimony, I review the PJM proposed cost allocation and find it to be inequitable for the customers of Maryland due to the failure to use the Multi-Driver Project method to assign costs according to Public Policy Requirements and Objectives. I also discuss an opportunity to improve the CWIP cost allocation to better assign costs to the causers and beneficiaries.

**Q. Please summarize your conclusions.**

A. My conclusions are as follows:

- Regarding RTEP projects related to Northern Virginia data center load growth:

   - A primary driver for the high levels of data center load growth in the region is the Virginia Data Center Exemption, a tax law designed to incentivize data center investment in the state.
   - The data center load growth, driven by Virginia Public Policy Requirements and Objectives, resulted in a significant transmission need. PJM has proposed many projects in the RTEP to address this need.
   - The current cost allocation of load-ratio share and DFAX allocation for these projects does not properly reflect their nature as a Public Policy Requirement and Public Policy Objective. The costs from projects directly resulting from data center load growth should be allocated via the Multi-Driver Project method.
- Regarding RTEP projects using and/or requesting CWIP:
   - The proposed CWIP cost allocation uses 2022 peak load to determine the load-ratio share.
   - Due to the massive data center load growth in Northern Virginia, the load-ratio share will change significantly between 2022 and 2028.
   - Since the RTEP projects are being built to address an unprecedented 2028 spot load, the use of the 2022 peak load to determine the load-share ratio is inadequate and inequitable.

**Q. Please summarize your recommendations to FERC.**

A. My recommendations are as follows:

- Regarding RTEP projects related to Northern Virginia data center load growth:
    - PJM should have identified all projects required to address Northern Virginia data center load, and officially categorized said projects as Public Policy Requirements and Objectives due to the Virginia Data Center Exemption.
    - PJM should define the associated projects as Multi-Driver Projects with costs allocated according to public policy-based enhancement/expansion.
- Regarding RTEP projects using and/or requesting CWIP:
    - For all projects identified to be required based on the Northern Virginia data center load, I recommend that the projected 2028 load-ratio share be used to determine CWIP cost allocation.

**Q. How is your testimony organized?**

A. In Section II, I provide background information relevant to the case, including, (1) an overview of the 2022 RTEP Window 3 process, (2) the scale and impact of the projects, and (3) further details on the unique and notable aspects of the 2022 RTEP Window 3 process.

## II. Background

**Q. What is the purpose of this section?**

A. This section provides background information on the following topics:

1) An overview of the 2022 RTEP Window 3 process, including PJM's load forecasting methodology, transmission needs analysis, and cost allocation methods.
2) An overview of the scale and impact of the RTEP projects.
3) The unique and notable aspects of the 2022 RTEP Window 3 process, including changes to the process that impacted the cost allocation methodology PJM followed to assign costs to LDAs.

### A. Overview of the 2022 RTEP Window 3 Process

**Q. Can you begin by explaining the RTEP process at a high-level?**

A. Yes. PJM is responsible for conducting a long-range Regional Transmission Expansion Plan ("RTEP") process to regularly identify changes to the grid and determine transmission needs to ensure reliability. When needs are identified, PJM opens a competitive planning "window" so transmission owners and other developers can submit solutions to address the need. These needs and potential solutions are discussed by stakeholders and PJM staff through PJM's Transmission Expansion Advisory Committee ("TEAC"). Following the review process, PJM staff submit a recommended set of projects to the PJM Board of Managers for consideration, approval, and inclusion in the RTEP.

The current window at issue is the 2022 RTEP Window 3. As described by PJM, the primary factors being considered in this window are (1) up to 7,500 MW of new data center load, and (2) more than 11,000 MW of generation deactivations across the PJM footprint.[1]

While this case centers around the cost allocation of projects in the RTEP, it is important to understand how and why projects are included to determine whether the cost allocation is equitable and accurate. Given the impact load demand has on projects selected for the RTEP, the methods PJM uses to determine load growth are particularly crucial to review.

**Q. How does PJM forecast load?**

A. PJM uses a Load Forecast Model to create an independent forecast of monthly and seasonal peak load and load management. PJM's Load Forecast Model is a 15-year monthly forecast under a range of weather conditions for each PJM zone, locational deliverability areas ("LDA"), and regional transmission operator ("RTO"). The model utilizes historical, hourly load data reported by Electric Distribution Company ("EDC") planners, while considering factors such as appliance usage, expected economic growth, distributed solar generation and battery storage, electric vehicle adoption, and historical weather patterns.[2]

---

[1] "PJM's Role in Regional Planning/2022 RTEP Window 3" PJM, (Nov. 20, 2023) https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjms-role-in-regional-planning-2022-rtep-window-3.ashx

[2] "PJM Manual 19: Load Forecasting and Analysis", Page 12. PJM. https://www.pjm.com/directory/manuals/m19/index.html#Sections/Attachment_B_Load_Forecast_Adjustment_Guidelines.html

**Q. How does PJM learn about and account for large new loads in the model?**

A. PJM's Load Forecast Model utilizes load adjustments to supplement the base forecast. While it is the EDCs' responsibility to report historical load data, PJM also solicits forecasts from EDCs annually for updates on large load shifts. If a zone is expected to experience significant load change (positive or negative), PJM will apply a load forecast adjustment by adjusting model inputs or explicitly changing the modeled forecast.[3] PJM's Load Analysis Subcommittee reviews submitted load changes and performs the analysis required to establish a degree of certainty and magnitude of load changes. These analyses attempt to isolate the impact of the load and produce a high and low schedule for load adjustment requests.[4]

**Q. How does PJM verify that large new loads are "real and significant"?**

A. PJM follows the validation process below:[5]

1) PJM determines if load is publicly acknowledged through media releases, press releases, regulatory processes, etc.
2) PJM verifies that the requesting EDC and/or Load Serving Entity ("LSE") has or will adjust its own financial and planning forecast to account for the spot load growth (this may also be substantiated by a Letter of Agreement and/or

[3] PJM Manual 19: Load Forecasting and Analysis at Page 14
[4] PJM Manual 19: Load Forecasting and Analysis at Page 26-28
[5] PJM Manual 19: Load Forecasting and Analysis, Attachment B.

Electric Service Agreement provided to PJM by the EDC/LSE on a confidential basis).

3) PJM communicates with its economic forecast vendor(s) to ascertain whether the load shift is reflected in the economic forecast and determines whether the economic impact is consistent with the load impact.
4) PJM verifies that any behind-the-meter ("BTM") adjustment complies with PJM's BTM process.
5) EDC/LSE provides PJM with an independent analysis of the impact of load change.

**Q. Once the load forecast is verified, how are projects selected?**

A. Once the load forecast is verified, PJM identifies local constraints, regional constraints, reactive power needs, the cumulative impact of generation changes and deactivations, and adherence to all applicable criteria.[6] Proposed projects are then evaluated under different scenarios to assess performance, scalability, impact, validated cost, risks, and efficiencies.[7] Once the projects are identified, the costs are allocated to the responsible parties.

**Q. What is PJM's current cost allocation method for RTEP projects?**

A. PJM allocates regional project enhancements using two allocation methods:

[6] PJM, NERC, SERC, RFC and local Transmission Owner FERC 715 criteria. "2022 RTEP Window 3 Reliability Analysis Report", Page 7, PJM. https://www2.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx
[7] 2022 RTEP Window 3 Reliability Analysis Report, Page 19

1) The load ratio share, which allocates RTEP project costs amongst zones, based on each zone's non-coincident peak load.
2) The solution-based DFAX, which assigns cost responsibility based on benefits received from a transmission facility by looking at the load demand from LDA over system components.[8] The DFAX formula only applies to transformers and transmission lines and is re-calculated each year to appropriately allocate costs towards the regions that have experienced load growth and experienced the most benefit from upgrades.

For projects that have not been completed, CWIP cost allocation is determined at the time the project was included in the RTEP and shall remain unchanged until the project goes into service.[9] Once in service, the costs will be recalculated annual as discussed above.

**B. Overview of the Scale and Impact of the RTEP Projects**

**Q. What is the total cost for the transmission projects included in 2022 RTEP Window 3?**

A. On December 11, 2023, the PJM Board approved the Window 3 Projects, which include baseline upgrades with an estimated overall RTEP net increase of approximately $5,085.85 million.[10]

---

[8] "Cost Allocation & Cost Recover," PJM Transmission Replacement Process Senior Task Force. (June 2016) https://www.pjm.com/~/media/committees-groups/task-forces/trpstf/20160603/20160603-item-04-education-module-6-cost-allocation-and-recovery.ashx

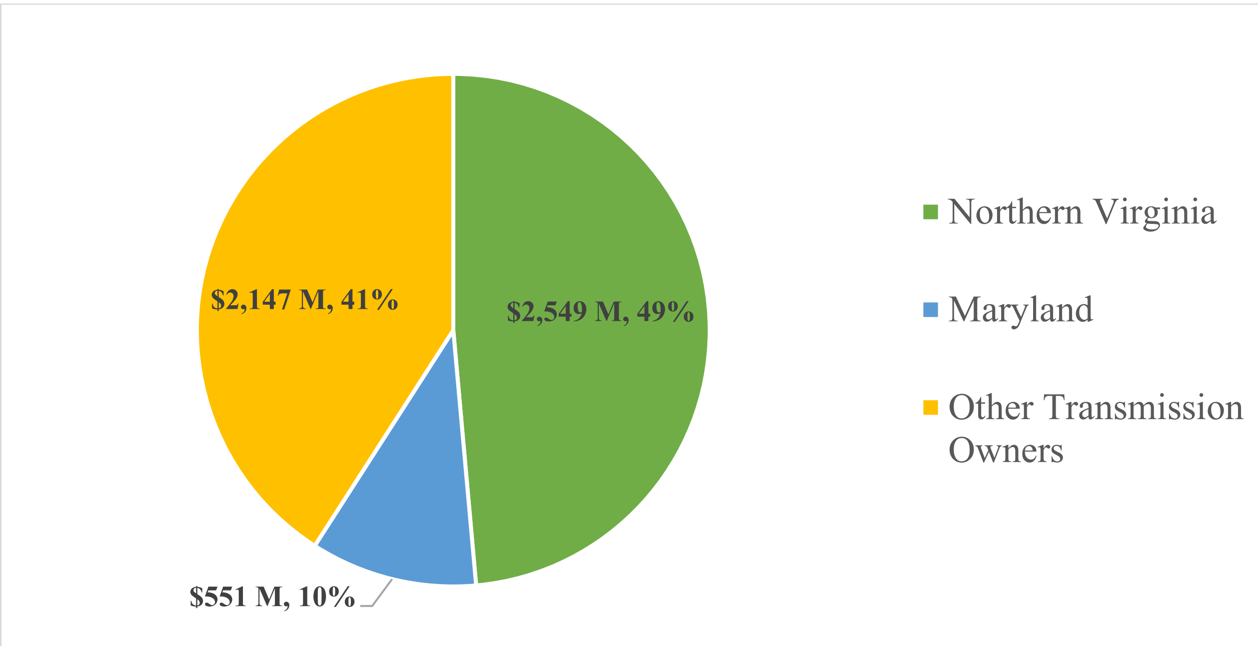
[9] PJM OATT, Schedule 12 (b) (iii) (H) (1)

[10] See PJM Interconnection, L.L.C., Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board (Dec. 2023), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjmteac-board-whitepaper-december-2023.ashx.

**Q. What costs will PJM allocate to Maryland?**

A. Under PJM's cost allocation methodology, Maryland will be charged approximately $551 million, or roughly 10 percent of the total costs.[11]

*Figure 1: 2022 Window 3 RTEP Project Cost Allocation*

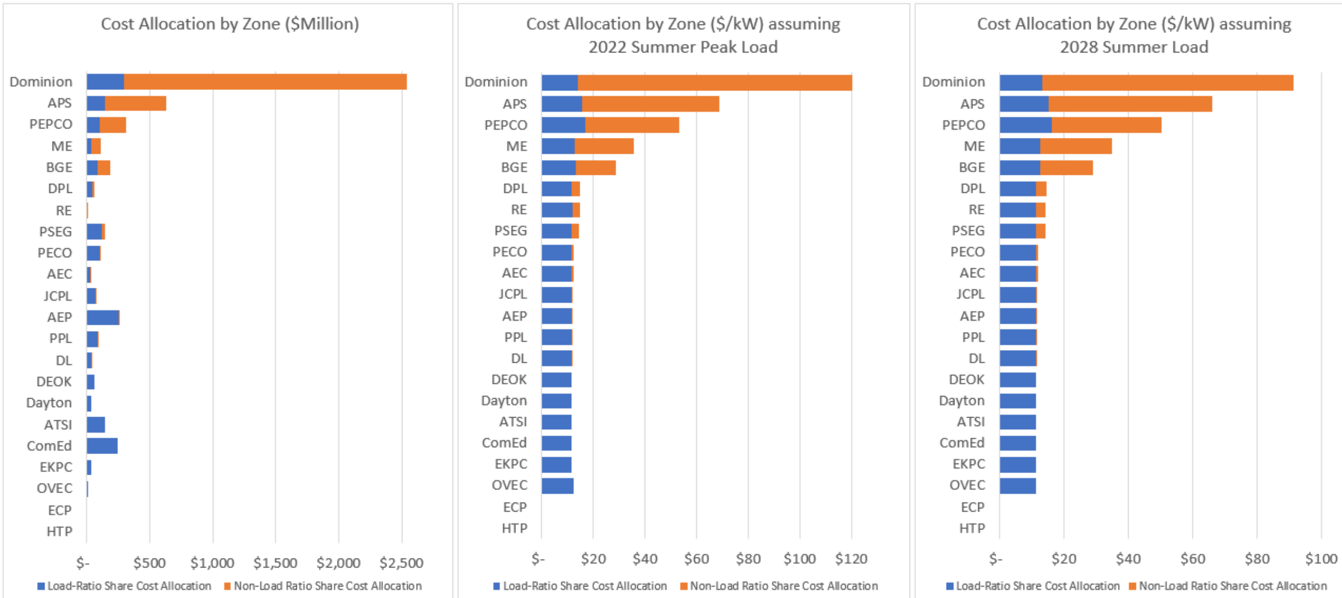



While Northern Virginia is projected to incur 49 percent of the total cost, this does not tell the full story. The majority of the project costs are driven by projected 2028 load (see next subsection for details). A potentially more insightful metric for understanding the impact on ratepayers for each LDA is $/kW according to 2028 peak load. As shown in Figure 2, while Dominion (i.e. Northern Virginia) remains the utility with the highest cost allocation in absolute terms, the Maryland utilities, including Allegheny Power ("APS"), Baltimore Gas & Electric ("BGE"), and Potomac Electric Power ("PEPCO") have been allocated high costs

[11] RTEP Window 3 Reliability Analysis Report

relative to their peak load, while their benefits are not proportionately high. To illustrate this, I developed a number of graphs shown below. The first graph replicates the data presented in Figure 3 of PJM's "TEAC Recommendations to the PJM Board – December 2023" meant to capture all the capital costs that each LDA would be allocated on a total cost basis. The second graph replicates the same data dividing the costs by each LDA's 2022 peak demand, showing that Maryland utilities are disproportionately impacted, all while receiving no benefits. Finally, the third graph which has been developed *only for illustration purposes* recalculates the load ratio allocations based on the 2028 projected peak and divides the total allocation by the 2028 peak, showing that Dominion's costs would be further reduced as they would be borne by a much larger load.

*Figure 2. 2022 RTEP W3 project cost by utility.*[12,13,14]




## C. Unique and Notable Aspects of the 2022 RTEP Window 3 Process

**Q. What load forecast was used by PJM for determining the RTEP projects?**

A. In early 2022, PJM shared its 2022 load forecast, which was used as the starting point for the RTEP process.[15] This load forecast indicated high data center load growth particularly in Northern Virginia. In summer 2022, actual peak load for Dominion Energy was measured at 21,156 MW, higher than the projected peak of 20,424 MW from the 2022 load forecast, which PJM suggests was as a result of

[12] The first graph replicates data from Figure 3 of the PJM Report "TEAC Recommendations to the PJM Board – December 2023", 20231205-pjm-teac-board-whitepaper-december-2023.ashx
[13] 2028 summer peak load from "PJM Load Forecast Report: January 2023", Table B-1, PJM Resource Adequacy Planning Department, https://www.pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx
[14] Note: APS and PEPCO are multi-jurisdictional (APS is 15 percent Maryland jurisdictional, PEPCO is 70 percent Maryland jurisdictional). BGE is 100% Maryland jurisdictional.

[15] "2022 RTEP Window 3 Reliability Analysis Report", Page 4, PJM. https://www2.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx

accelerated data center development. As a result, in an attempt to stay ahead of the rapid data center increases, PJM refined its forecast and created the 2023 load forecast to use in the 2022 RTEP Window 3.[16] This was an atypical deviation from PJM's standard process.

**Q. Please describe the differences between the 2022 and 2023 load forecasts.**

A. Initially, the 2022 RTEP Window 3 Reliability Analysis was performed using a five-year out 2027 case.[17] When the 2023 load forecast was developed, PJM continued to use the five-year lookahead approach, now using 2028 as the planning year. The overall change to summer peak for the planning year by utility and region is shown in Table 1. Dominion sees by far the largest increase in the new forecast, growing by 4,715 MW, or 19.7% in 2028 compared to the old forecast.

[16] "2022 RTEP Window 3 Reliability Analysis Report", Page 4, PJM. https://www2.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx
[17] 2022 RTEP Window 3 Reliability Analysis Report, Page 5.

*Table 1. Summer peak increase or decrease from 2022 load forecast to 2023 load forecast for the planning year of 2027 or 2028.*[18]

| | **2027/28 Forecast Delta**[19] | |
|---|---|---|
| **Utility/Region** | **MW** | **%** |
| AEP | 320 | 1.4% |
| APS | 799 | 9.1% |
| ATSI | -671 | -5.4% |
| COMED | -121 | -0.6% |
| DAYTON | 5 | 0.2% |
| DEOK | -178 | -3.3% |
| DLCO | -110 | -3.9% |
| EKPC | -151 | -6.8% |
| OVEC | 5 | 5.6% |
| PJM WESTERN | 12 | 0.0% |
| DOM | **4,715** | 19.7% |
| PJM RTO | 3,014 | 2.0% |

While an initial RTEP project solution set was identified under the 2022 forecast using 2027 as the planning year, after the 2023 load forecast was developed the 2028 case was then used to analyze the impact of new data center load growth. PJM observed that there were an increased number and severity of overloads compared to the 2027 case, and thus determined it would be prudent to utilize the 2028 scenario to evaluate project proposals for robustness.[20]

[18] "PJM Load Forecast January 2023", PJM Resource Adequacy Planning Department, https://www.pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx

[19] MW values are calculated as the difference between the summer peak load in the 2023 load forecast for planning year 2028, and the 2022 load forecast for planning year 2027. % values use the same difference, divided by the total summer peak.

[20] 2022 RTEP Window 3 Reliability Analysis Report, Page 6.

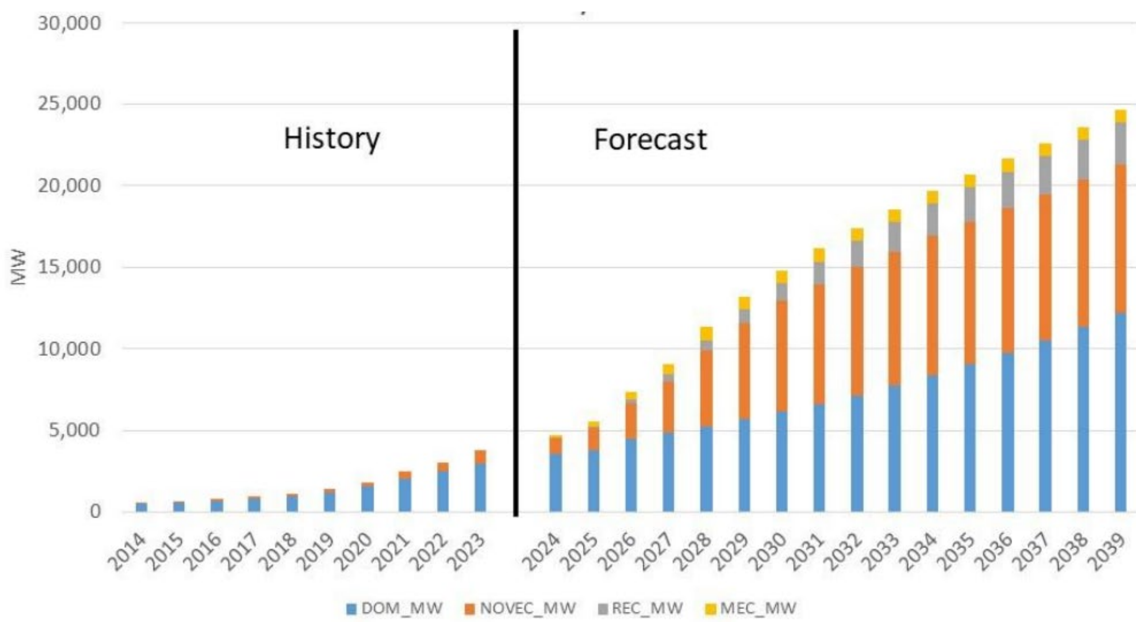
**Q. What data center load growth did PJM identify after switching to the 2023 Load Forecast?**

A. For the 2023 Load Forecast Report, PJM received new data center load forecasts from Dominion, First Energy, and NOVEC. Dominion estimates between 4.2 to 5 percent annual total load growth over the next decade, much of which is from new data centers.[21] These higher energy flows add to an already-increasing concentrated load pocket of data centers in Northern Virginia, fueled by tax incentives that I explain in later sections.[22]

When isolating the load growth projections just to data centers, the accelerated growth is even more stark. PJM projects that electricity load demand from data centers in the Dominion zone (including Dominion, NOVEC, Mecklenburg Cooperative, and Rappahannock Cooperative) will grow from approximately 3.5 GW in 2023, to over 15 GW in 2028, to nearly 25 GW in 2039, as shown in Figure 3 (Figure taken from source).[23]

[21] 2022 RTEP Window 3 Reliability Analysis Report at Page 4.
[22] 2022 RTEP Window 3 Reliability Analysis Report at Page 4
[23] "2024 Load Forecast Supplement", PJM Resource Adequacy Planning Department, (Jan 2024), https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20230626/20230626-item-05---dominion-load-adjustment-method_results.ashx

*Figure 3. Dominion zone total data center historical and forecasted mid-July load.*




**Q. Is this rate of load growth common?**

A. No. This spot load growth is unprecedented and carries with it new uncertainties and risk. Neither the load magnitude nor the timing that it materializes can be projected with confidence given the lack of historical data and experience, posing a significant risk to stakeholders across the planning region should the load not appear at the forecasted magnitude and timeline. Cost allocations for the selected 2022 W3 RTEP projects will negatively affect stakeholders across the planning region as they will receive no reliability benefits should the forecasted load not materialize as expected, but will still be expected to bear the cost burden of the selected projects.

**Q. Will this rate of load growth cause reliability concerns according to PJM?**

A. Yes. New data center load growth primarily in the Dominion zone, with some contribution from Allegheny Power ("APS"), will cause heavy regional transfers and voltage violations under N-0 conditions, requiring major voltage support.[24] Furthermore, PJM analysis states that the 2027 forecast "shows an extensive set of violations ranging between single contingencies, generation deliverability and N-1-1 reliability criteria performance violations."[25]

**Q. What other factors in the 2022 RTEP Window 3 are causing additional reliability concerns?**

A. Not only does PJM face the challenge of anticipated new load growth, but it must also account for the effects of scheduled generator retirements. Two generating units located in Maryland, the Brandon Shores and Wagner generating units, have planned retirements in 2025.[26] Additionally, the Warrior Run generating facility announced to PJM in September 2023 its plans to either retire the facility in 2024 or to mothball the facility through January 2026 as it converts to burning biomass

---

[24] PJM modeled ~5,700 MW and ~1,500 MW respectively of data center load in their reliability analysis. "2022 RTEP Window 3 Reliability Analysis Report," PJM, Table 1, (Dec. 5, 2023) https://www2.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx

[25] "Dominion Northern Virginia Area Violations," PJM. https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx

[26] Generator Deactivation Notices, PJM, (Dec. 1, 2023), https://www.pjm.com/planning/service-requests/gen-deactivations/generator-deactivation-notices

rather than coal.[27] These retirements also influenced PJM's decision to use the 2028 load forecast as a robustness check.

## III. Data Center Spot Load Growth Should be Considered a Public Policy. Project Costs Allocated Using The Proportional Multi-Driver Project Method

**Q. What do you discuss in this section and why is it important?**

A. In this section, I describe Virginia's tax laws related to data centers, how this may impact data center growth, how the growth pertains to the RTEP transmission projects, and why the current cost allocation methods are insufficient for this unique circumstance. I present the FERC-approved method of cost allocation via the Proportional Multi-Driver Method to address public policy requirements and objectives in combination with reliability and market efficiency measures.

**Q. Are there any state policies that could be influencing the data center load growth?**

A. Yes. In 2010, Virginia amended its tax law to incentivize the development of new data centers in the Commonwealth.[28] The change has led to significant industry growth, which has an outsized impact on both economic development and electricity demand, particularly in Northern Virginia under the EDCs Dominion, NOVEC, and First Energy. This expansion is expected to continue at an accelerated pace, as the EDCs project further exponential data center demand growth in the coming years as I will discuss in more detail in this section.

---

[27] "*Retirement Notification for Warrior Run*", AES Warrior Run Limited Partnership to PJM, (Sep. 30, 2023), https://www.pjm.com/-/media/planning/gen-retire/deactivation-notices/warrior-run-deactivation-notice.ashx

[28] Va. Code § 58.1-609.3

**Q. What is Virginia's "Data Center Exemption"?**

A. Effective July 1, 2010, Virginia amended Va. Code § 58.1-609.3 to provide a Retail Sales and Use Tax exemption specifically for data centers, commonly referred to as the "Data Center Exemption". Data center facilities are exempt from retail sales and use tax if they meet the following criteria: [29]

> (i) is located in a Virginia locality;
>
> (ii) results in new capital investment on or after January 1, 2009, of at least $150 million; and
>
> (iii) results in the creation on or after July 1, 2009, of at least 50 new jobs by the data center operator and the tenants of the data center, collectively, associated with the operation or maintenance of the data center provided that such jobs pay at least one and one-half times the prevailing average wage in that locality.

**Q. What has been the economic impact of the Data Center Exemption for the Commonwealth of Virginia?**

A. According to an audit of state spending in 2021, Virginia incurred $837 million in Data Center Exemptions from 2011 to 2020.[30] Going forward, Virginia projects approximately $3.6 billion in additional tax subsidies have and will be extended via the exemption for fiscal years 2022-2025.[31] This has had a substantial impact

---

[29] *Id.*
[30] "Economic Development Incentives 2021: Spending and Performance", Joint Legislative Audit and Review Commission, (Nov. 8, 2021) https://jlarc.virginia.gov/pdfs/reports/Rpt557.pdf
[31] Virginia Senate Finance and Appropriations Committee, *Panel Discussion: Data Centers in Virginia* (Nov. 17, 2023), p. 6. https://sfac.virginia.gov/pdf/retreat/2023%20Tysons/13.%20Datacenters%20Panel.pdf

on the local economy, as detailed in another 2021 report by the Northern Virginia Technology Council.[32] Northern Virginia has the largest data center market in the United States, exceeding the next five largest markets combined. It is reported that data centers provided the Commonwealth with 15,500 jobs, $174 million in state tax revenue, and $15 billion in overall economic output. For Loudon County, VA specifically, for every $1.00 in county expenditures due to data centers, they provided $13.20 in tax revenue. It is estimated that 90 percent of the economic activity of these data centers was induced by the Data Center Exemption.[33]

**Q. What is the relevance of the Data Center Exemption in this proceeding?**

A. As described in detail in Section II, PJM projects that electricity load demand from data centers in the Dominion zone will grow exponentially from approximately 3.5 GW in 2023, to over 15 GW in 2028, to nearly 25 GW in 2039.[34] This projected demand growth in Virginia, driven by the Data Center Exemption, amplified Dominion's 2023 load forecast, which informed PJM's overall load forecast to determine the necessary RTEP projects.[35]

---

[32] Understand Data Centers' Impact on Virginia, Northern Virginia Technology Council, 2021 https://www.nvtc.org/topics/data-center-and-cloud/report/

[33] "Data Center and Manufacturing Incentives: Economic Development Incentives Evaluation Series", Joint Legislative Audit and Review Commission, Page 14 (Jun. 17, 2019) https://jlarc.virginia.gov/pdfs/reports/Rpt518-1.pdf

[34] "2024 Load Forecast Supplement", PJM Resource Adequacy Planning Department, (Jan 2024), https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20230626/20230626-item-05---dominion-load-adjustment-method_results.ashx

[35] "2022 RTEP Window 3 Reliability Analysis Report", Page 3, PJM. https://www2.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx

**Q. Do PJM and FERC consider "Public Policy Requirements" and "Public Policy Objectives" in the RTEP process?**

A. Yes. Public Policy Requirements and Objectives are "Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long-term planning considerations."[36] For example, Public Policy Requirements are "policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity."[37]

FERC Order No. 1000 and PJM's currently effective Operating Agreement allow the RTEP process to consider Public Policy Requirements and Objectives to determine reliability needs.[38] This is significant because it sets a precedent that state-policy-driven transmission enhancements or expansions can be developed in the RTEP process.

---

[36] PJM Operating Agreement, OA Definitions O – P.
[37] *Id.*
[38] "Consideration of Federal and State Public Policy Initiatives Through PJM's Long-Term Regional Transmission Planning Process," Page 2, PJM, (Dec. 15, 2023) https://www.pjm.com/-/media/committees-groups/workshops/ltrtp/2023/20231215/20231215-informational-only---position-paper---consideration-of-federal-and-state-public-policy-initiatives-through-pjm-ltrtp-process.ashx

**Q. Should the Virginia Data Center Exemption be considered a Public Policy Requirement and/or Objective?**

A. Yes. While Public Policy Requirements and Objectives have largely been defined as those related to renewable energy requirements, the Data Center Exemption represents a similar state-driven policy with comparable impacts on the power system. Virginia has intentionally modified its tax code to attract data center customers to the state, which results in load growth that necessitates transmission expansion and upgrades for reliability.

However, unlike renewable energy projects whose purpose is directly tied to the operation of the electrical grid, the purpose of the Data Center Exemption is to drive economic development in the Commonwealth. Put differently, the grid impacts from the data centers are a secondary outcome of the public policy, rather than the direct intention of the policy. Regardless, the projects included in the RTEP to serve load in Northern Virginia are driven by Virginia's state laws and policies favoring data center development, and accordingly are the outcome of Virginia Public Policy Requirements and Objectives.

**Q. Does PJM provide a method that would allow Public Policy Requirements and Objectives to be allocated costs alongside other drivers of transmission expansion/upgrade?**

A. Yes, the Multi-Driver Project method. This method, proposed by PJM and approved by FERC in 2015, allows PJM to plan for and select transmission enhancements or expansions that address a combination of reliability, economics, and Public Policy and Requirements and Objectives.[39] With this approach, the resulting cost assigned to each driver will then be charged to responsible customers in the same way that it would have been charged under a single driver project.[40]

PJM's Operating Agreement states that "[PJM] shall determine whether a proposal(s) meets the definition of a Multi-Driver Project."[41] Based on my conversations with counsel, this provision puts the responsibility on PJM to determine whether a project is Multi-Driver that combines solutions that address reliability, economics and/or public policy. Once identified as a Multi-Driver Project, the costs would be allocated according to the different components (i.e. reliability-based enhancement/expansion, economic based enhancement/expansion, or public policy-based enhancement/expansion).[42]

**Q. Is there an alternative mechanism in PJM's Operating Agreement to assign costs from Public Policy Requirements and Objectives?**

A. Yes. Costs from Public Policy Requirements and Objectives can alternatively be allocated through a "State Agreement". If one or more states identify a transmission enhancement or expansion that the state or states have determined to be necessary to address Public Policy Requirements and Objectives, a State

[39] "Order Accepting Tariff Revisions Subject to Conditions re PJM Interconnection, L.L.C. et al under ER14-2864 et al.", FERC, (Feb. 20, 2015), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20150220-3054&optimized=false
[40] *Id.* Paragraph 16.
[41] PJM OA Schedule 6, Section 1.5.10 (h) https://agreements.pjm.com/oa/4777
[42] PJM OA Schedule 6, Section 1.5.10 (d) https://agreements.pjm.com/oa/4777

Agreement can be used to allocate costs. "Under this approach, the states sponsoring the project voluntarily agree to be responsible for its costs, and if the project is not pursued as a Supplemental Project, the costs will be allocated only to customers in the states sponsoring the project, under a cost allocation method submitted by the Transmission Provider…for consideration and filing."[43]

If enacted, the State Agreement would be the basis for one of the drivers in PJM's Multi-Driver method. The calculation for the cost allocation would then be 50 percent allocated on a load-ratio share, and 50 percent assigned in accordance with the Public Policy Requirement and Objective beneficiary as determined by the State Agreement.[44]

**Q. What is your recommendation regarding the data center load growth and its impact on cost allocation?**

A. The data center load growth in Northern Virginia can be linked to the Data Center Exemption in Virginia tax codes and thus should be officially categorized as load growth due to Public Policy Requirements and Objectives. Further, due to the localized nature of the load growth and the economic benefit that Virginia receives as a result of the industrial tech business influx, the costs associated with the transmission expansion/upgrade to serve the load growth should be allocated to Virginia and the associated EDCs. In fact, allocating the cost to other states would

[43] *Id.* Page 8.
[44] "Order Accepting Tariff Revisions Subject to Conditions re PJM Interconnection, L.L.C. et al under ER14-2864 et al.", FERC, Paragraph 16, (Feb. 20, 2015), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20150220-3054&optimized=false

conflict with Cost Allocation Principle #2 of FERC Order No. 1000, in which FERC states that "it is required that aggregate cost of these transmission facilities be allocated roughly commensurate with aggregate benefits."[45] The aggregate benefits of these transmission projects clearly include the economic benefits that will be realized by Virginia – and not by Maryland – through the development of new data centers.

To properly allocate these costs, PJM should define the associated projects as Multi-Driver Projects with costs allocated according to public policy-based enhancement/expansion. This approach is the most equitable as Virginia state policies lead to the transmission expansion need and the state receives most of the economic benefits of data center growth; therefore, the cost of the infrastructure needed to support its state economic development policy requirements and objectives should be directly allocated.

**IV. The use of 2022 Peak LDA Load for cost allocation has a disproportionate impact on non-Virginia ratepayers.**

**Q. What do you discuss in this section and why is it important?**

A. In this section, I raise concerns about how the application of the Construction Work in Progress ("CWIP") incentive to new transmission solutions can

[45] FERC Docket No. RM10-23-000; Order No. 1000, Page 458.

disproportionately impact some of the LDAs, especially the ones that are projected to experience lower load growth.

**Q. Explain the CWIP incentive.**

A. A utility receiving 100 percent CWIP recovery can recoup costs during construction instead of adding to the capital investment included in the rate base after a project is completed.[46] In the best-case scenario, current returns on CWIP allow for lower overall construction costs, lower charges to customers in the form of depreciation, and a more gradual rate increase (as opposed to a rate shock).

**Q. How does PJM intend to use the load-ratio and DFAX methods to allocate CWIP costs for RTEP projects?**

A. Under PJM's approach, half of the RTEP project CWIP costs would be allocated using the load-ratio share allocator and the remaining half would be allocated using the DFAX allocator. [47] Thus, 50 percent of the facility's costs would be allocated on a load-ratio share basis that assigns the costs proportionally to the peak load in each zone. For the 2022 RTEP Window 3, this peak load is defined based on 2022 loads.[48] The other 50 percent of the costs are allocated based on the DFAX method, determined by power flow analysis.

[46] Docket No. ER24-472-000, Request for Approval of Transmission Rate Incentives. https://www.pjm.com/directory/etariff/FercDockets/7748/20231122-er24-472-000.pdf
[47] Docket No. EL21-39-000, Island Power Authority v. PJM Interconnection, L.L.C. https://www.pjm.com/-/media/documents/ferc/orders/2021/20210625-el21-39-000.ashx
[48] "Transmittal Letter", PJM Interconnection, L.L.C., Docket No. ER24-843, Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades, (Jan 10, 2024)

**Q. Explain why CWIP's load allocation methodology does not follow the beneficiary pays principle in this case.**

A. The beneficiary pays principle is the idea that those who cause or enjoy the advantages of newly built transmission infrastructure should bear the costs of its construction, rather than socializing them amongst all customers. As explained in Section II, RTEP project costs will be socialized across the entire region, even though Virginia stands to benefit the most from the investment. This is also true of RTEP project CWIP costs. However, this misalignment is exacerbated for CWIP costs due to the fact that peak loads in 2022 (which are used to determine the load-ratio for CWIP costs) are not representative of future peak loads that will emerge as a direct result of the RTEP projects. Since many of the RTEP projects are being built specifically to accommodate future load growth in Northern Virginia due to data center development, the RTEP project CWIP costs should similarly use that future load to allocate costs. The 2022 load-ratio share will significantly change by 2028, when the transmission projects are complete, and the new load has arrived. Thus, continuing with the current CWIP load allocation methodology would not follow the beneficiary pays principle. Instead, it would cause non-Virginia ratepayers to pay a disproportionate share of the RTEP project costs in the near term that is not commensurate with the benefits received once the projects are completed.

This critique on CWIP is shared by FERC. The most recent 2022 FERC Notice of Proposed Rulemaking ("NOPR") raised concerns over CWIP's current application. FERC has proposed to prohibit the CWIP incentive for transmission facilities selected in regional plans for the purposes of cost allocation. FERC believes that the CWIP incentive may shift too much risk to customers and result in unjust and unreasonable rates.[49]

**Q. Are any of projects that PJM selected in the RTEP Window 3 requesting CWIP?**

A. Yes. PJM's selected projects have already begun to request CWIP. In November 2023 NextEra Energy submitted a request for one hundred percent of prudently incurred CWIP in rate base for their MidAtlantic Resiliency Link Project.[50] This project will construct a new 500 kV transmission line crossing Virginia, West Virginia, Maryland, and Pennsylvania, as well as a new 500/138 kV substation located in Virginia. This project is meant to address the unprecedented load growth demand resulting from data center loads in northern Virginia. Thus, if CWIP is approved, it will result in higher rates for customers across three states who are not direct causers of the transmission need.

**Q. Do you recommend an alternative method for allocating CWIP costs in this case?**

A. Yes. Because the load growth underpinning these RTEP project CWIP costs are specific to Virginia -- and the state will gain economically from the industrial tech

[49] Summary of FERC's April 2022 NOPR on Transmission Planning, Cost Allocation, and Generator Interconnection https://www.troutman.com/insights/summary-of-fercs-april-2022-nopr-on-transmission-planning-cost-allocation-and-generator-interconnection.html#_edn25
[50] 186 FERC ¶ 61,052 https://www.pjm.com/directory/etariff/FercOrders/7130/20240119-er24-472-000.pdf

business boom -- Virginia and its LDAs should bear a greater share of the costs than what has been proposed. For all projects identified to be required based on the Northern Virginia data center load, I recommend that the projected 2028 load-ratio share be used to determine CWIP cost allocation, or another alternative that aligns with the beneficiary pays principle.

**Q. Do you anticipate any challenges with implementing this approach?**

A. Not in the long run. However, there may be some near-term challenges due to the fact that there is presently confusion over which projects in the 2022 W3 solutions package are related to data center load growth and which ones are related to generator retirements. Thus, going forward, I recommend that FERC require PJM to provide a clearer explanation of the cause behind specific transmission enhancements in its RTEP process. This will help inform the allocation of RTEP project costs, including CWIP costs. A clearer explanation would also be consistent with Cost Allocation Principle #5 from FERC Order No. 1000, which requires the provision of a transparent method for determining benefits and identifying beneficiaries.[51]

## Conclusion

**Q. Please restate your recommendations to FERC.**

A. My recommendations are as follows:

[51] FERC Docket No. RM10-23-000; Order No. 1000, https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf

- Regarding RTEP projects related to Northern Virginia data center load growth:
    - For all projects identified to be required based on the Northern Virginia data center load, PJM should officially categorized said projects as Public Policy Requirements and Objectives due to the Virginia Data Center Exemption.
    - PJM should define the associated projects as Multi-Driver Projects with costs allocated according to public policy-based enhancement/expansion.
- Regarding RTEP projects using and/or requesting CWIP:
    - For all projects identified to be required based on the Northern Virginia data center load, I recommend that the projected 2028 load-ratio share be used to determine CWIP cost allocation.

**Q. Does this conclude your testimony?**

A. Yes, it does.

# Ron Nelson

Senior Director

Ron is a Senior Director at Strategen and a subject matter expert in gas and electric Advanced Rate Design, Cost of Service Studies, and Decarbonization. Ron leads a team that provides expertise and expert testimony on numerous topics, including multi-year utility rate plans, performance incentive mechanisms, cost of service modeling, line extension policies, residential and commercial rate design, renewable energy program design, system planning, DER interconnection cost allocation and recovery, and DER integration.

## Contact

**Location**
Portland, Oregon

**Email**
rnelson@strategen.com

**Phone**
+1 (510) 679-1976

## Education

**MS**
**Agricultural and Resource Economics**
Colorado State University
2013

**BA**
**Environmental Economics**
Western Washington University
2011



## Work Experience

### Senior Director

Strategen / Portland, OR / 2018 - Present

+ Subject matter and testimony expert in advanced rate design, embedded and marginal cost of service modeling, performance-based regulation, gas decarbonization, and DER integration and compensation.
+ Designing and implementing policies and programs to decarbonize energy systems including deployment of distributed energy resources, demand-side management programs, energy storage and grid integration.
+ Expert witness and advisor that has testified across 12 states in over 60 proceedings and supported multiple state commissions in various proceedings

### Economist

Minnesota Attorney General's Office / St. Paul, MN / 2013 - 2017

+ Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models.
+ Analyzing issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO.
+ Reviewed and made recommendation to improve gas company pipeline replacement programs, demand response tariffs, performance metrics, and rate designs.

### Graduate Research Associate

Colorado State University / Fort Collins, CO / 2011 - 2013

### Economic Research Assistant

Washington State University / Mount Vernon, WA / 2009 - 2011

## Domain Expertise

Regulatory Strategy

Gas Decarbonization

Rate Design

Performance-Based Regulation

Performance Inventive Mechanisms

Cost of Service Analysis

DER Compensation

Rate Case Support

Electric Vehicles

Renewable Energy Program Design



## Expert Testimony

**67. In the Matter of the Application of Potomac Electric Power Company for and Electric Multi-Year Plan for the Distribution of Electric Energy**
**Electric Rate Design**
**Direct**

**66. In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, files pursuant to NRS 704.110 (3) and (4), addressing its annual revenue requirement for general rates charged to all classes of customers**
**Electric Rate Design**
**Testimony**

**65. In the Matter of Advice No. 1923 – Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reset the General Rate Schedule Adjustments, to Place into Effect Revised Base Rates, and to Implement Other Phase II Tariff Proposals to Become Effective June 15, 2023**
**Electric Rate Design**
**Testimony**

**64. Application of Baltimore Gas and Electric Company for a Second Electric and Gas Multi-Year Plan**
Electric and Gas Rate Design, Gas Transition, Bill Impacts
Direct | Rebuttal | Surrebuttal

**63. Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: D.P.U. 22-170, 23-06, 23-09, and 23-12 On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher**
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

**62. Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. Docket No. 22-0486. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.**
Hosting Capacity, Value of DER, Peak Load Reduction, Flexible Interconnection, DERMS
Direct

**61. Ameren Illinois Company. Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service. Docket No. 23-0067. On Behalf of Environmental Law and Policy Center, Environmental Defense Fund, Natural Resources Defense Council, Illinois State Public Interest Research Group, Inc.**
Gas Transition, Capital Planning, Line Extensions, Non-Pipeline Alternatives, Bill Impacts, Gas System Planning, PBR, Rate Design
Direct

**60. Pennsylvania Public Utility Commission V. Philadelphia Gas Works. Docket No. R-2023-3037933. On Behalf of The Office of Consumer Advocate**
Weather Normalization Adjustment and Decoupling

**59. DEP and DEC EVSE Program. Docket No. 2022-158-E. On Behalf of The South Carolina Office of Regulatory Staff**
EV Program Design
Direct | Surrebuttal

**58. Petition of Philadelphia Gas Works for Approval on Less than Statutory Notice of Tariff Supplement Revising Weather Normalization Adjustment. Docket No. 2022-3034264. On Behalf of the Office of the Consumer Advocate**
Weather Normalization Adjustment

**57. In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance Based Regulation. On Behalf of the North Carolina Attorney General's Office**
Cost of Service, Rate Design, Performance-Based Regulation
Direct

**56. Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations, and Conditions of Service for Electric Service in the State of Oklahoma and to Approve a Formula Based Rate Proposal . On Behalf of AARP**
Cost of Service and Rate Design
Responsive Testimony

**55. Montana-Dakota Utilities Co. 2022 Electric Rate Increase Application. On Behalf of AARP**
Cost of Service and Rate Design
Direct | Surrebuttal

**54. Northern Indiana Public Service Company Rate Case. On Behalf of Citizens Action Coalition**
Cost of Service and Rate Design
Direct

## Expert Testimony (Continued)

**53. Central Maine Power Company: Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. Section 307, Docket 2022-00152, On Behalf of the Governor's Energy Office w/Panelists Caroline Palmer and Nikhil Balakumar. On Behalf of the Governor's Energy Office**

Marginal Cost of Service, Performance-Based Regulation, Distribution System Planning

Direct

**52. Georgia Power Company's 2022 Rate Case. On Behalf of Americans for Affordable and Clean Energy**

Electric Vehicle Rate Design

Direct

**51. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Citizen's Utility Board of Minnesota**

Rate Riders, Fuel Clause Risk Sharing, and MYRP Structure

Direct | Rebuttal

**50. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Clean Energy Organizations**

Advanced Rate Design, Regulatory Sandbox, TOU Rate Design

Direct | Surrebuttal

**49. NSTAR Electric Company d/b/a Eversource Energy, Capital Investment Project Filing: D.P.U. 22-51 through 55 On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher**

DER Integration, Interconnection and Cost Allocation

Direct | Surrebuttal

**48. Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: Shutesbury (D.P.U. 22-61) On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher**

DER Integration, Interconnection and Cost Allocation

Direct

**47. In the Matter of Delmarva Power and Light Company's Application for an Electric Multi-Year Plan (Case No. 9681) On Behalf of the Office of People's Counsel w/ Panelist Jorge Camacho**

Distribution System Planning, Capital Investment Plan, Multi-Year Rate Plan Structure, Revenue Decoupling

Direct (No. 21) | Rebuttal (No. 23)

## Expert Testimony (Continued)

**46. Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021) (D.P.U. 22-47) On Behalf of the MA AGO w/ Panelists Jorge Camacho, Eli Asher, and Fred Schaefer**
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

**45. Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. (Docket No. 22-0432 and 22-0442) On Behalf of NRDC, Sierra Club, EDF, RHA and Little Village Environmental Justice Organization (LVEJO)**
Electric Vehicle Rate Design and Energy Management Systems

**44. Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act (Docket No. 22-0431 and 22-0443) On Behalf of NRDC, Sierra Club, EDF, and RHA**
Electric Vehicle Rate Design and Energy Management Systems

**43. In the Matter of the Application of Oklahoma Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma**
Cost of service, rate design, formula rate plan
Direct | Stipulation

**42. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Commonwealth Edison Company, Docket No. 22-0067 On Behalf of NRDC**
Demand Response and Electric Vehicle Performance metrics
Direct | Rebuttal

**41. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Ameren Illinois Company, Docket No. 22-0063 On Behalf of NRDC**
Demand Response and Electric Vehicle Performance metrics
Direct | Rebuttal

**40. In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC**
Performance-based regulation and gas decarbonization
Direct

**39. Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021)**
DER integration, Flexible interconnection, Capital Investment Project
Direct | Surrebuttal

## Expert Testimony (Continued)

**38. In the Matter of the Application of Oklahoma Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma**
Cost of service, rate design, formula rate plan
Direct | Stipulation

**37. In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota. Docket No. E-015/GR-21-335. On Behalf of CUB Minnesota**
Cost recovery, cost of service, and revenue apportionment
Direct | Surrebuttal

**36. In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC**
Performance-based regulation and gas decarbonization
Direct

**35. Phase 2: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office**
EV Program Design and Load Management
Direct

**34. Phase 2: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office**
EV Program Design and Load Management
Direct

**33. Phase 2: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office**
EV Program Design and Load Management
Direct

**32. Phase 1: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office**
EV Program Design and Load Management
Direct

## Expert Testimony (Continued)

**31. Phase 1: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office**
EV Program Design and Load Management
Direct

**30. Phase 1: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office**
EV Program Design and Load Management
Direct

**29. In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota**
Prudency Review
Direct

**28. In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota (Docket No. 21-435) On Behalf of the Clean Energy Organizations**
Rate Design and Line Extension Policy
Direct

**27. In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota**
Prudency Review
Direct

**26. Green Mountain Power (DKT: 2021-3707-PET) On Behalf of Green Mountain Power**
Multi Year Rate Plan
Prefiled Direct Testimony

**25. Public Service of Oklahoma (DKT: 202100055) On Behalf of AARP**
ECOSS and Rate Design
Responsive Testimony

**24. Duquesne Light Company (DKT: R-2021-3024750) On Behalf of the PA OCA**
Transportation Electrification, Load Control
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

## Expert Testimony (Continued)

**23. PECO (DKT: R-2021-3024601) On Behalf of the PA OCA**
Transportation Electrification, Load Control
Direct (note: please type in the docket number, the testimony cannot be directly referenced)

**22. Rocky Mountain Power (DKT: 20-035-04) On Behalf of the Utah Office of Consumer Services**
Embedded COS, Rate Design, and AMI Rollout
Direct

**21. Minnesota Power* On Behalf of the MN CUB**
ECOSS and low-income rate design

**20. Pennsylvania Power and Light: DER Management Petition (DKT: P-2019-3010128) On Behalf of the PA OCA**
DER integration
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

**19. Public Service of New Hampshire (dba Eversource Energy) (DKT: DE 19-057) On Behalf of the NH OCA**
Embedded and marginal COS, Rate Design, and PBR
Direct

**18. Liberty Utilities (DKT: DE 19-064) On Behalf of the NH OCA**
Marginal COS, Rate Design, decoupling and PBR
Direct
*Settled before direct was filed

**17. Oklahoma Gas and Electric (DKT: 201800140) On Behalf of AARP**
Rate Design and CCOSS
Direct

**16. Vectren Energy Delivery of Ohio (DKT: 18-0298-GA-AIR) On Behalf of the Environmental Law and Policy Center**
CCOSS and Rate Design
Direct | Supplemental | Case link

**15. Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG**
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case link

**14. Ameren Illinois Company (DKT: 18-0537) On Behalf of the IL AG**
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case file

## Expert Testimony (Continued)

**13. Public Service Company of Oklahoma (DKT: 201800096) On Behalf of AARP**
Formula Rates, Performance Metrics, Rate Design, and CCOSS
Direct

**12. Oklahoma Gas and Electric (DKT: 201700496) On Behalf of AARP**
CCOSS and Revenue Apportionment
Responsive | Case link

**11. Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG**
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

**10. Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG**
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

**9. Otter Tail Power (DKT: E-002/GR-15-1033) On Behalf of the MN OAG**
Marginal and Embedded CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Case link

**8. Xcel Energy (DKT: E-002/GR-15-826) On Behalf of the MN OAG**
CCOSS, Rate Design, and Performance-Based Regulation
Direct | Rebuttal | Surrebuttal |Case link

**7. Minnesota Energy Resources Corp. (DKT: G-011/GR-15-736) On Behalf of the MN OAG**
CCOSS and Rate Design
Direct : | Rebuttal | Surrebuttal | Case link

**6. CenterPoint Energy (DKT: E-002/GR-15-424) On Behalf of the MN OAG**
CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Surrebuttal | Case link

**5. Dakota Energy Association (DKT: E-002/GR-14-482) On Behalf of the MN OAG**
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal | Case link

**4. Xcel Energy (DKT: E-002/GR-13-868) On Behalf of the MN OAG**
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal: Case Link

**3. Xcel Energy, Minnesota Energy Resources Corp, CenterPoint Energy (DKT: 21-138)**
Natural Gas Prudence Testimony
Case Details | Direct

## Expert Testimony (Continued)

**2. Minnesota Energy Resources Corp. (DKT: G-011/GR-13-617) On Behalf of the MN OAG**
CCOSS
Direct | Surrebuttal | Case Link

**1. CenterPoint Energy (DKT: G-008/GR-13-316) On Behalf of the MN OAG**
CCOSS
Direct | Surrebuttal | Case Link