UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Maryland Office of People's Counsel	)	
Complainant, v.	)	
PJM Interconnection, LLC and Transmission Owners Designated Under Attachment A to the Consolidated Transmission Owners Agreement (CTOA)	))	DOCKET NO. EL26-63-000
	)	
Respondents.	)	
	)	

RESPONSE IN OPPOSITION AND ANSWER
OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

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OVERVIEW

In May 2026, the Maryland Office of People's Counsel ("OPC") filed, and later amended, a complaint (the "Complaint") under Section 206 of the Federal Power Act ("FPA") challenging as unjust and unreasonable PJM's Schedule 12 cost-allocation methodology, which assigns Maryland ratepayers more than $2 billion in capital costs for regional baseline transmission projects driven by massive, forecasted geographically concentrated large-load and data center demand occurring outside Maryland. OPC's central contention is straightforward and grounded on longstanding cost-causation principles: Under the existing PJM transmission cost allocation methodology, Maryland ratepayers are required to shoulder a substantial and disproportionate share of the costs of these facilities that they did not cause and which do not provide them roughly commensurate benefits.

Remarkably, the majority of the respondents largely agree with the Complaint's factual premises. Several respondents who otherwise oppose the Complaint concede that data centers are driving the transmission expansion addressed in OPC's Complaint.[1]

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[1] See PJM Answer at 24 ("there is no doubt that data center and other large load additions are causing increased demand for electricity, leading to increased costs to construct more Regional Facilities."); PJM Transmission Owners ("PJM TOs") Answer at 30 ("Now the expansion appears driven by interconnecting large loads."); Russo Aff. at 17 ("large load growth is an important driver of recent RTEP upgrades."); Clean Energy Buyers' Association ("CEBA") Comments at 6 ("large loads are certainly driving the need for and benefiting from regional transmission facilities."); Old Dominion Electric Cooperative ("ODEC") Answer at 5–6 (large loads, "predominantly data centers, are the primary driver of the unprecedented growth in electricity demand," and PJM's RTEP "includes unprecedented amounts of transmission facilities . . . as necessary to serve large loads."); Southern Maryland Electric Cooperative ("SMECO") Answer at 2 (attributing affordability and reliability pressures to "massive load growth caused by large loads.").

Others concur that these loads are arriving at unprecedented scale and speed.[2] Respondents themselves also acknowledge the need to rethink practices once viewed as foundational.[3] The Commission has reached much the same preliminary conclusion. The Commission's June 18, 2026, Show Cause Order found that PJM's Tariff may be unjust and unreasonable because it lacks adequate mechanisms to prevent cost shifting among transmission customers.[4] Although several respondents argue that OPC's Complaint should be dismissed because the Show Cause Order addresses the same subject matter,[5] as Nelson and Eiden explain, respondents' invocation of the Show Cause Order "only serves to reinforce [the Complaint's] legitimacy and relevancy" with respect to the need to change and modernize PJM's tariff.[6] Moreover, failure to address the Complaint's

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[2] ODEC Answer at 5 (ODEC "fully acknowledges that large loads, predominantly data centers, are the primary driver of the unprecedented growth in electricity demand, and that this growth is expected to continue."); SMECO Answer at 2 ("These are unique, unprecedented times where the safety and reliability of the electric system, and the ability of customers to afford electric service, are being threatened by massive load growth caused by large loads."); *see also* Sierra Club at 9 ("Unprecedented large load growth presents a novel circumstance that requires a new approach to remain just and reasonable.") New Jersey Board of Public Utilities ("NJBPU") at 6 (citing new phenomenon of very large loads from a single industry creating unprecedented forecast error and stranded asset risk); Independent Market Monitor (IMM) at 4 (asserting that data centers are "uniquely stressing the system's ability to accommodate them."
[3] Attach. A (Nelson and Eiden Rebuttal Aff.) at 2; *see also* PJM Answer at 26-27 ("The Commission needs to decide whether the fundamental rationale has changed in a way that would make the principles underlying the hybrid method no longer just and reasonable."); CEBA Comments at 18 ("the complaint is entirely correct that PJM's load forecasting methodology badly needs attention from this Commission"); Data Center Coalition ("DCC") Protest at 18 ("DCC agrees that steps can and should be taken to improve load forecasting accuracy"); ODEC Answer at 3 ("ODEC also supports efforts by PJM, the PJM Transmission Owners and the Commission . . . to ensure that the costs associated with accommodating large loads are borne by the new large loads driving them.") SMECO Answer at 8 ("SMECO has consistently supported reforms, at the state and federal level, that would allocate large-load-caused costs to the large loads that cause them rather than spreading them across the general body of ratepayers.").
[4] *PJM Interconnection, LLC,* Order Instituting Proceeding Under Section 206 of the Federal Power Act, 195 FERC ¶ 211, P 66 (2026) ("Show Cause Order").
[5] *See e.g.*, PJM TOs Answer at 7, 21-22; ODEC Answer at 7-10; SMECO Answer at 7-8.
[6] Attach. A (Nelson and Eiden Rebuttal Aff.) at 5.

subject matter, and its focus on responsibility for regional baseline projects, effectively would enable data center loads to evade a major portion of their responsibility for paying for more than half of the massive level of transmission-related capital expenditures ("capex") planned for PJM during the planning cycles for its most recent regional transmission expansion plans ("RTEPs"), driven by large load data center load growth.[7] A failure to address to correct the unjust and unreasonable cost allocation of recent baseline projects would also undermine the Ratepayer Protection Pledge.[8]

Yet even as respondents accept the factual basis for OPC's Complaint, they resist remedial action. Essentially, they argue PJM's methodology for allocating the enormous costs of regional baseline transmission expansion projects should remain untouched. Some contend that the existing methodology has already been found just and reasonable while ignoring the realities of large load impacts[9] while others suggest, without evidence, that Maryland is seeking to avoid its fair share.[10] But as Nelson and Eiden conclude, "it is logically inconsistent to acknowledge that large loads impact several of PJM's existing

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[7] The absolute level of capital expenditures ("capex") on transmission baseline projects across the three regional transmission expansion plans ("RTEPs") challenged by the OPC complaint constitute more than half the capex for transmission projects in PJM from 2023 to 2025, inclusive of both supplemental and baseline projects *See*, PJM, *RTEP 2025*, p. 350, Figure 5.2 ($27.2 billion in baseline project capex; $19 billion in supplemental project capex). The levels of aggregate transmission capex for baseline projects in PJM, as well, are unprecedented, comprising 35% of PJM's aggregate 2023 transmission rate base. *See*, S&P Global, *PJM transmission growth rebounds; datacenters boost outlook for future expansion* (March 10, 2025) (reporting aggregate TO transmission rate base in PJM at $63.15 billion for 2023).
[8] Failure to map responsibility for the costs of baseline projects to data center loads is contrary to the Ratepayer Protection Pledge ("RPP"), by failing to address more than half the transmission capex expenditure committed to under the three recent annual PJM RTEP cycles. The President, Proclamation 11014, *Ratepayer Protection Pledge*, 91 Fed. Reg. 11,439 (March 4, 2026) (providing, among other matters, for data centers to "pay for new power delivery infrastructure upgrades to service their [loads]").
[9] PJM Answer at 26-27.
[10] *See e.g.,* CEBA Comments at 4-5 (suggesting, inaccurately, that Maryland's choice to rely on imported energy justifies payment of a larger use-based cost allocation).

processes but conclude that one of the largest cost categories within PJM should remain intact with no cost allocation changes."[11]

The consequences of leaving the challenged Schedule 12 cost allocation methodology intact are severe for Maryland. As already shown, the three challenged RTEP procurement windows—2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1—account for more than $22 billion in new baseline transmission investment across PJM.[12] Of that, Schedule 12 assigns Maryland $2,001,204,009 in capital costs ($1,322,523,125 through solution-based DFAX and $678,680,885 through load-ratio share) producing $1,621,476,976 in Maryland revenue requirements over ten years.[13]

Even a cursory review shows that Maryland did not cause this expansion. Approximately 90 percent[14] of the large-load adjustments (comprised of forecasted data center loads) to the PJM annual load forecasts driving the expansion, across RTEP 2022 Window 3, RTEP 2024 Window 1 and RTEP 2025 Window 1—cumulatively, 38.9 GW—are concentrated in four zones: Dominion, AEP, ComEd, and PPL.[15] None includes Maryland, and the zones covering Maryland show "only marginal forecasted load growth" over the same period.[16]

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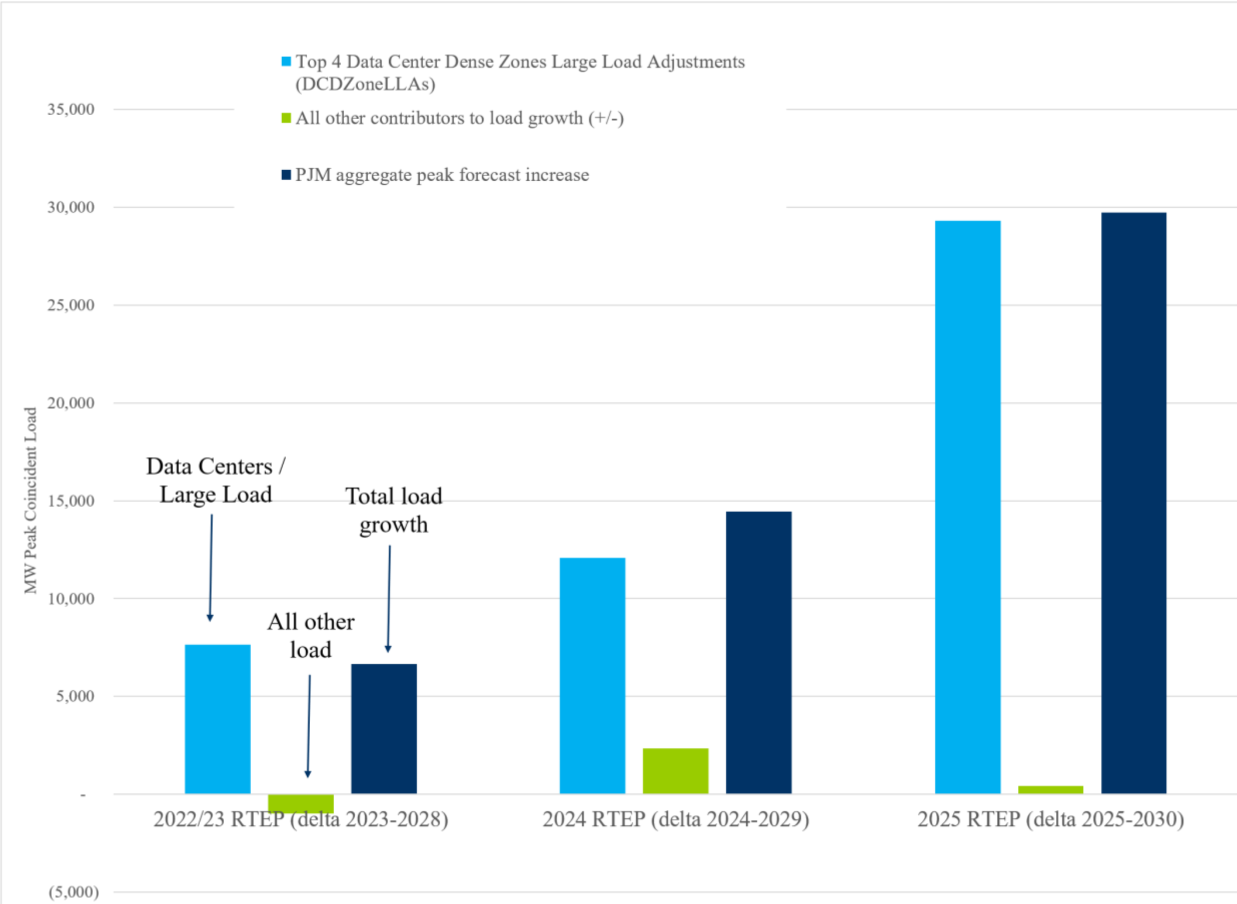
[11] Attach. A (Nelson and Eiden Rebuttal Aff.) at 13.
[12] Amended Complaint at 5, n.4.
[13] *Id*. at 6-7, Tables 1 and 2.
[14] The Amended Complaint alleged that 80 percent of large loads were concentrated in four PJM zones. Amended Compl. at 13. The 80 percent figure was from 2032, using the 2026 Load Forecast table available at the time. The 90 percent figure is more accurate because it is the average of the 2028/29/30 RTEP model case years for the 2022-23/24/25 RTEP Windows covered by the Complaint.
[15] Amended Complaint at 13.
[16] Amended Complaint at 21.

The following graph shows the overwhelming contribution of PJM's large load adjustments, comprised almost entirely of forecasted data center load growth concentrated in the four "data center" dense zones in PJM, to forecasted PJM system peak load growth for the fifth year forward from the most recent year of the PJM annual forecast, current at the time of each RTEP. It is the fifth year forward forecasted level of load that is used to plan the transmission expansion committed to in each RTEP. Thus, the graph depicts the relative (and massive) contribution of large load data centers to the forecasted load increases used to dimension the transmission facilities procured through each of the three RTEP procurement windows challenged by this Complaint (i.e., 2022 RTEP Window 3, using the 2023 PJM forecast for 2028; 2024 RTEP Window 1, using the 2024 PJM forecast for 2029; and 2025 RTEP Window 1, using the 2025 PJM forecast for 2030). PJM's forecasting method, to isolate "large load adjustments" ("LLAs") by zone and their attribution (from data centers) and then to include the LLAs in the annual forecast allows for the mapping (geographic and temporal) of the data center load forecast to the drivers of the increases in the overall forecast.

Figure 1: Incremental forecasted coincident peak load growth — PJM 2022/3, 2024 and 2025 RTEP Year 5 of PJM annual forecast (from Nelson and Eiden Rebuttal Affidavit)



The remainder of this Response in Opposition and Answer proceeds in three parts. Part I shows that OPC satisfied its Section 206 burden by identifying the challenged Schedule 12 provisions and supporting its claim with detailed quantitative and expert analysis and that the Show Cause Order does not moot the Complaint because it leaves regional cost allocation—the largest disputed cost category—undisturbed. Accordingly, the respondents' various Motions to Dismiss the Complaint are without merit. Part II shows that neither the load-ratio-share nor the solution-based DFAX component allocates costs roughly commensurate with benefits when load growth is this large and this geographically concentrated, and that existing mechanisms like Transmission Security Agreements and state retail tariffs fall short in protecting ratepayers. Part III argues that the Commission has several approaches to remedies that should be considered in a paper hearing including zonal allocation as an immediate measure; direct assignment of network upgrade costs to the large loads that cause them; an "and" pricing option that entails charging a large load both the embedded network rate and a separate incremental rate for the upgrades built to serve it, with no credit of one against the other; and related planning reforms needed along with a refund effective to the Complaint's filing date. Also accompanying and in support of this Response in Opposition and Answer is the affidavit of Ron Nelson and Andy Eiden labelled Attachment A.

OPC files this Response in Opposition and Answer pursuant to Rule 385.213(a) of the Commission's Rules of Practice and Procedure.[17]

I. The Commission should deny the respondents' motions to dismiss the Complaint.

Several respondents move to dismiss the Complaint on overlapping threshold and procedural grounds. First, PJM, the Indicated PJM Transmission Owners ("PJM TOs"),

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[17] 18 C.F.R. §385.213(a). Rule 213 does not prohibit answers to motions to dismiss but does not allow answers to responses. But the Commission routinely accepts answers like this one that will aid the decisional process. *See e.g., Salsa Solar Energy, LLC v. Public Service Co. of Colorado*, 190 FERC ¶ 61,108, at P 29 (finding that answer to answer will assist in decision-making)(2025); *accord RENEW Northeast, Inc. v. ISO New England Inc.*, 182 FERC ¶ 61,085, at P 47 (2023); *Potomac Economics, Ltd. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,039, at P 19 (2020); *Association of Businesses Advocating Tariff Equity Coalition of MISO Transmission Customers v. Midcontinent Independent System Operator, Inc.*, 148 FERC ¶ 61,049, at P 179 (2014).

PJM, ODEC, and SMECO contend in various forms that OPC failed to satisfy its initial evidentiary proof burden under FPA, section 206. They argue, among other things, that the Complaint fails to identify with sufficient specificity the tariff provisions or practices alleged to be unjust and unreasonable, relies on generalized or aggregate evidence rather than project-specific analysis, and fails adequately to demonstrate that the challenged cost allocations are not roughly commensurate with the benefits Maryland receives.[18] SMECO separately contends that OPC also must demonstrate, as part of making its prima facie case to warrant acceptance of OPC's Complaint before further investigation by the Commission, that its proposed replacement rate is just and reasonable.[19]

Second, the PJM TOs, ODEC, SMECO, and other respondents contend that the Commission's subsequent Show Cause Order in Docket No. EL26-67-000[20] either moots the Complaint, "effectively obviates"[21] the need for this proceeding, or warrants holding the Complaint in abeyance while the Show Cause proceeding moves forward.[22]

Finally, respondents advance several additional grounds for dismissal. PJM contends that it should be dismissed as a respondent because the PJM TOs possess exclusive section 205 filing rights over transmission rate design and cost allocation.[23] The PJM TOs argue that the relief OPC seeks would improperly intrude upon the States'

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[18] PJM TOs Answer at 13-18 (failure to meet burden and lack of specificity), PJM Answer at 28-31 (arguing Complaint lacks specificity and does not specify applicable statutory terms violated); ODEC Answer at 3-6.
[19] SMECO Answer at 10 (asserting that Section 206 imposes a dual burden to show rates are unjust and replacement rate is just and reasonable).
[20] *Id at n. 5.*
[21] PJM TOs Answer at 7, 21-25; ODEC at 7-10, SMECO at 7-8.
[22] SMECO Answer at 7-8.
[23] PJM Answer 4-5.

authority to protect retail ratepayers[24] and fault OPC for failing to pursue alternative dispute-resolution mechanisms before filing its Complaint.[25] None of these objections have merit.

A. OPC satisfied its Section 206 burden of proof.

1. The Section 206 prima facie standard governs.

To prevail on a complaint under Section 206 of the Federal Power Act, the complainant bears the initial burden to come forward with a prima facie showing that a rate or practice is unjust and unreasonable.[26] To make a prima facie showing, a complainant must identify the challenged action or practice and provide sufficient evidence and analysis explaining how it violates the applicable statutory or regulatory standard.[27] That showing, however, need not be immune from factual or methodological challenge; the Commission has denied dismissal where, notwithstanding respondents' criticisms of the complainant's analysis, the evidence submitted with the Complaint was

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[24] PJM TOs Answer at 15-17.

[25] PJM TOs Answer 18-20.

[26] *Solar Energy Industries Ass'n v. Midcontinent Independent System Operator, Inc.*, 185 FERC ¶ 61,186, P 18 & n.59 (2023) (holding that an FPA Section 206 complainant bears the initial burden to make a prima facie showing that the challenged tariff is unjust, unreasonable, unduly discriminatory, or preferential).

[27] **See** *e.g.*, *Coalition of Eastside Neighborhoods for Sensible Energy v. Puget Sound Energy, Inc*., 153 FERC ¶ 61,076, PP 59–60 (2015) (dismissing case where complainant failed to identify standard that was violated) ; *Cities of Anaheim, Azusa, Banning, Colton, Pasadena, & Riverside, Cal. v. Trans Bay Cable L.L.C.*, 146 FERC ¶ 61,100, PP 19, 23 & n.25 (2014). ("As set forth in the Commission's regulations, a complainant establishes *a prima facie* case if the complainant: (1) clearly identifies the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements; and (2) the complainant explains how the action or inaction violates the applicable statutory standards or regulatory requirements.")

sufficient to establish a prima facie case that the challenged rate may be unjust and unreasonable.[28]

Once the initial burden is met, the burden of producing evidence shifts to the respondent, although the ultimate burden of persuasion remains with the complainant. [29] Contrary to SMECO's assertion,[30] Section 206 does not impose a second burden on the complainant to establish, as part of its prima facie case, that its proposed replacement rate is just and reasonable,[31]

Respondents also contend that OPC failed to establish a prima facie case because the Complaint does not identify with sufficient specificity the Schedule 12 provisions it challenges and does not support its claims with sufficiently specific evidence and

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[28] *Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.*, 149 FERC ¶ 61,049, PP 183–184 (2014) ("*ABATE*")(finding that expert testimony submitted with ABATE's complaint, notwithstanding MISO's criticisms, was adequate to establish a prima facie case and overcome dismissal).

[29] *See e.g.*, *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs. Into Mkts. Operated by Cal. Indep. Sys. Operator Corp.,* Opinion No. 536, 149 FERC ¶ 61,116, at PP 45-47 (2014), *on reh'g,* 153 FERC ¶ 61,144 (2015), *aff'd sub nom. MPS Merchant Servs., Inc. v. FERC,* 863 F.3d 1155 (9th Cir. 2016) ("The party with the burden of proof bears the burden of production, or the need to provide sufficient evidence to establish a prima facie case. Once it meets that burden, however, the burden of going forward shifts to the opposing party, although the ultimate burden of persuasion remains with the proponent."). *NextEra Energy Seabrook, LLC*, 183 FERC ¶ 61,196, n.93 (2023) (finding complainant satisfied its burden and established a prima facie case, after which the burden shifted to respondent).

[30] SMECO incorrectly characterizes Section 206 as imposing a "dual burden" on OPC to establish both that the existing rate is unjust and unreasonable and that OPC's proposed replacement rate is just and reasonable. SMECO Answer at 10. The "dual burden" described in *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) is the Commission's obligation under Section 206: the existing rate must first be found unjust and unreasonable, after which the Commission must determine a just and reasonable replacement rate. Once a complainant satisfies its burden to establish the unlawfulness of the existing rate, "the burden then shifts to the Commission to determine the new just and reasonable replacement rate." *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, P 97 (2020). Section 206 does not condition OPC's prima facie case on proving both that the existing Schedule 12 methodology is unlawful and that its preferred replacement is the only just and reasonable alternative.

[31] *FirstEnergy Service Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) (rejecting "dual burden" as too high a standard for a § 206 complainant and explaining that it is the Commission's responsibility to determine a just and reasonable replacement rate).

analysis.[32] As shown in the next sections, those arguments mischaracterize both the Complaint and the showing required at the prima facie stage.

2. OPC specified the Schedule 12 methodology it challenges and offered extensive quantitative and expert evidence showing how the challenged methodology produces an unjust and unreasonable cost allocation.

Respondents incorrectly assert that OPC failed to identify with sufficient specificity the rate or practice alleged to be unjust and unreasonable.[33] The Complaint challenges the application of Schedule 12 of the PJM Tariff, specifically, the hybrid load-ratio-share and solution-based DFAX methodology, to baseline reliability projects approved through the 2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1.[34] The Nelson/Eiden Affidavit identifies the operative provisions still more specifically, citing Schedule 12 §§ (b)(i)–(ii), governing the 50-percent load-ratio-share/50-percent solution-based DFAX allocation for Regional Facilities and Necessary Lower Voltage Facilities; §§ (b)(iii)(B) and (b)(iii)(B)(1), governing the solution-based DFAX calculation; and § (b)(iii)(H)(2), governing the annual update to the DFAX allocation. [35] What's more, PJM itself admits that the Complaint clearly addresses core provisions of the PJM Tariff related to the use of the hybrid load-ratio share and DFAX methodologies for determining transmission cost allocation.[36] OPC's clear specification

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[32] *See e.g.* PJM TOs' Answer at 13–14; ODEC Answer at 4–5.
[33] PJM TOs' Answer at 13-17 (alleging failure to meet burden and lack of specificity), PJM Answer at 2 (arguing Complaint lacks specificity and does not specify applicable statutory terms violated); ODEC Answer at 3-6.
[34] Amended Compl. at 7, 18–20.
[35] Amended Compl., Attach. A (Nelson/Eiden Aff.) at 40–41, 53 & nn.76–79, 101.
[36] PJM Answer at n. 7 (acknowledging that hybrid cost allocation methodology resides in Section 12 of the PJM tariff).

of the tariff provisions it challenges distinguishes the Complaint from the authorities respondents cite, in which the complainants failed to identify any specific tariff provision or statute at all.[37]

Respondents' next claim—that OPC merely points to the magnitude of Maryland's transmission charges without demonstrating any defect in Schedule 12—fares no better. OPC's argument is not that Maryland's transmission costs are too high, but that Maryland is being allocated costs for transmission facilities built to serve data center load elsewhere in the PJM footprint that bear no reasonable relationship to the benefits Maryland actually receives. The mismatch between cost and benefit, not the dollar figure itself, is the defect that the Complaint identifies in Schedule 12's allocation methodology.

Nor does OPC contend, as the PJM TOs claim,[38] that the location of data centers outside Maryland, standing alone, renders the resulting transmission costs unjust and unreasonable. The geographic concentration of the load growth matters because Schedule 12 allocates costs through methodologies that, as alleged here, do not adequately track the location and cause of the incremental transmission need or the benefits resulting from it. OPC's claim is therefore not that Maryland should avoid costs simply because the data centers are located elsewhere, but that the costs allocated to Maryland under Schedule 12

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[37] *See e.g.*, *Coalition of Eastside Neighborhoods for Sensible Energy v. Puget Sound Energy, Inc.*, 153 FERC ¶ 61,076, P 59 (2015) (dismissing complaint that broadly invoked Orders 890, 1000, and 2000 and the applicable tariff, but failed to identify any specific provision allegedly violated); *Californians for Renewable Energy v. CAISO*, 174 FERC ¶ 61,204, P 33 (2021) (denying complaint where "we find that the complaint fails to identify any specific CAISO tariff provisions that are allegedly unjust and unreasonable.");

[38] PJM TOs Answer at 6.

are not roughly commensurate with the benefits Maryland receives from the transmission expansion those loads drive.

The Complaint and its accompanying affidavit then demonstrate how each component of the Schedule 12 methodology produces the cost mismatch that is the gravamen of OPC's case. Load-ratio share allocates costs according to each zone's share of PJM system peak without regard to the location or driver of the incremental transmission need and breaks down when, as here, the triggering load growth is both extraordinary and geographically concentrated.[39] The assumption that all zones benefit from transmission projects is the identical "basic fallacy" the Seventh Circuit condemned in *Illinois Commerce Commission v. FERC*,[40] and the very defect that drove PJM to abandon its 100 percent load-ratio-share method.[41]

Solution-based DFAX presents a different problem. It allocates costs based on modeled power flows as a proxy for benefits, but may not capture stability, short-circuit, dynamic-voltage, and other reliability impacts associated with concentrated data center loads that are unrelated to steady-state power flows.[42] The Commission and the D.C. Circuit recognized this as a shortcoming of DFAX in the *Artificial Island* and *Con Edison* proceedings.[43] The Nelson/Eiden Affidavit, accompanying the Complaint further

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[39] Amended Compl. 33–36, Attach A (Nelson and Eiden Aff.) at 40–43, 50.
[40] 756 F.3d 556, 564 (7th Cir. 2014).
[41] Amended Compl. 33–36 and Attach. A (Nelson and Eiden Aff.) at 41–42, 50.
[42] Amended Compl. at 36-39; Attach. A (Nelson and Eiden Aff.) at 47-48.
[43] Amended Compl. at 36–41, discussing *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10 (D.C. Cir. 2021)("*Artificial Island*") and *Consolidated Edison Co. of N.Y., Inc. v. FERC*, 45 F. 4th 265 (D.C. Cir. 2022).

illustrates that mismatch by identifying $155.82 million in Reactive Power VAR Reinforcements allocated through DFAX even though those reinforcements address non-flow-based reliability needs.[44]

The PJM TOs overstate the significance of the qualified language in the Nelson/Eiden Affidavit regarding short circuits. Nelson and Eiden state that PJM "may have included costs related to short circuits" in the 2022 RTEP Window 3.[45] But although that particular observation is qualified, the Affidavit separately identifies and states that those costs are "not due to steady-state-load flow-based project needs" and therefore are inappropriately allocated through solution-based DFAX.[46] Thus, uncertainty concerning the single short-circuit component does not render the separate VAR speculative or warrant dismissal of the Complaint.

Finally, the Complaint alleges that Schedule 12's annual DFAX update creates a further cost shift when forecasted large loads fail to materialize. Costs initially associated with those forecasted loads are shifted away from the zones in which the growth had been expected and onto Maryland and other zones that did not cause the underlying investment.[47]

Nelson and Eiden then go on to quantify the economic consequences of the problems with the current defective cost allocation methodology. Using PJM data for the three challenged RTEP windows, Nelson and Eiden calculate that Schedule 12 assigns

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[44] Amended Comp. Attach. A (Nelson/Eiden Aff.) at 43–50.
[45] *Id*. at 44-45.
[46] *Id.*
[47] Amended Compl. at 40–42, Attach. A (Nelson/Eiden Aff.) at 53–54.

Maryland $2,001,204,009 in transmission capital costs — $1,322,523,125 through solution-based DFAX and $678,680,885 through load-ratio share — yielding $1,621,476,976 in cumulative Maryland revenue requirements over ten years.[48] The Affidavit ties those figures to the location of the load growth driving the expansion: the four zones with the largest load adjustments (Dominion, AEP, ComEd, and PPL) account for 90 percent of PJM's load growth and are projected to increase aggregate load 64 percent by 2036, while Maryland's load grows only modestly over the same period.[49] Solution-based DFAX accounts for 67 percent of Maryland's ten-year revenue impact, which Nelson and Eiden attribute to Maryland utilities' proximity to the northern Virginia data center cluster.[50] In short, the $2.001 billion transmission capital costs are not merely problematic due solely to magnitude but because the amount represents the quantification of the costs improperly assigned to Maryland under the challenged cost allocation methodology.

The evidence and expert analysis backing OPC's Complaint far exceeds anything present in the precedent respondents cite to support dismissal. Those cases all involved generalized, vague or speculative allegations. In *Central Hudson Gas & Elec. Corp. v. FERC*,[51] the section 206 challenger there lost because it "relied on speculation about future harms" and lacked "real-world evidence." OPC's harm is the opposite of

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[48] *Id.* at 5–6, Tables 1–2.
[49] Amended Compl. Attach A (Nelson/Eiden Aff.) at 62–63. The Amended Complaint originally alleged that large load accounts for 80 percent of PJM load growth, but has been revised to 90 percent based on the average of 2028/29/30 RTEP years.
[50] Id. at 62.
[51] 138 F.4th 531, 544–46 (D.C. Cir. 2025).

speculative because it is money already assigned in three completed procurement windows. In *Californians for Renewable Energy*, the Commission dismissed a complaint consisting of "conclusory generalizations and speculation," including allegations that high prices were unlawful without evidence showing that the prices were not the product of legitimate market forces. [52] And in *CSolar IV South*, the Commission declined to impose a broad market-wide remedy based on a perceived, inchoate threat that had not yet produced the alleged harm. [53]

This Complaint presents neither circumstance. OPC challenges an existing tariff methodology that is currently being applied to identified RTEP projects and has already produced identified cost allocations to Maryland. The harm OPC identifies is neither generalized nor speculative; it is quantified, ongoing, and traceable directly to Schedule 12's allocation methodology.[54] Nor does OPC ask the Commission to infer unlawfulness from the size of Maryland's charges alone, as in the cases involving complaints about

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[52] *Californians for Renewable Energy v. California Independent System Operator Corp.*, 174 FERC ¶ 61,204, PP 32, 34, 36 (2021) (dismissing allegations consisting of conclusory generalizations and speculation and rejecting claims concerning high prices where complainant failed to provide evidence showing that the prices were not the product of legitimate forces of supply and demand), cited in PJM TO Mot. to Dismiss at 14.

[53] *CSolar IV South, LLC v. California Independent System Operator Corp.*, 142 FERC ¶ 61,250, P 47 (2013) (declining to impose a broad market-wide solution based on a perceived inchoate threat), cited in PJM TO Mot. to Dismiss at 13–14.

[54] For this reason, *Columbia Gulf Transmission, LLC v. FERC*, 106 F.4th 1220, 1232 (D.C. Cir. 2024), also does not support dismissal. The Transmission Owners cite *Columbia Gulf* for affirmance of dismissal where the complainant merely quoted tariff language and alleged general violations. PJM TO Mot. at 13–14. Here, OPC does considerably more: it identifies the operative Schedule 12 provisions, explains how the challenged allocation mechanisms allegedly produce the cost-causation mismatch, and supports that showing with expert analysis and PJM data.

high costs.[55] The costs are relevant because they are the economic measure of the specific allocation defects alleged in the Complaint.

3. Respondents' demand for project-by-project proof lacks any precedent and would convert a prima facie inquiry into a merits determination.

The PJM TOs fault OPC for failing to "dispute a single project" approved in the three challenged RTEP windows, for failing to show that any particular project does not benefit Maryland customers, and for failing to provide an analysis of "the cost allocation or benefits associated with a single transmission project.[56] But respondents cite no authority requiring a complainant challenging a cost-allocation methodology to establish its case project-by-project as a prerequisite to proceeding under Section 206.

Moreover, it does not follow that OPC must perform a complete project-by-project causation and benefits analysis to make a prima facie showing. The relevant question at this stage is whether the Complaint already contains sufficient evidence supporting the alleged defect in the challenged methodology. It does. OPC identifies the allocation mechanisms it challenges, explains how those mechanisms allegedly cease to track cost causation and benefits when extraordinary load growth is geographically concentrated, identifies the three RTEP windows in which those mechanisms produced the challenged

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[55] *See Champion Energy Marketing LLC v. PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,059, P 30 (2015), cited in ODEC Answer at 5. There, the Commission held that the magnitude of the balancing operating reserve charges assessed to the complainant did not itself demonstrate that the applicable PJM Tariff provisions were unjust and unreasonable. ODEC Answer at 5. Unlike *Champion Energy*, OPC does not rely on the amount of the charges as proof of unlawfulness; it identifies the alleged defects in the allocation methodology and uses the resulting Maryland costs to quantify the consequences of those defects.

[56] PJM TOs Answer at 17; ODEC Answer at 4–5.

allocations, compares the concentration of the load growth driving the expansion with Maryland's comparatively much more modest, forecasted load growth, and quantifies the resulting Maryland allocations. It also identifies a concrete example of non-flow-based reliability costs allocated through DFAX. Thus, OPC's claim does not depend upon the possibility that a future project-by-project analysis will uncover an unlawful allocation; the Complaint already supplies evidence supporting the alleged methodology-level mismatch.

The Commission's decision in *California Public Utilities Commission v. Pacific Gas & Electric Co.*,[57] shows that missing information cannot defeat an otherwise substantiated complaint. There, the complainants acknowledged that missing and unclear cost information prevented a comprehensive evaluation of the challenged rates and that a definitive determination could not yet be made.[58] Nevertheless, the Commission found that the complaint supplied sufficient support to establish a prima facie case and held that the remaining material factual questions should be resolved through further proceedings. The Commission emphasized that it was "not here making a finding on the merits," but was determining only that the complainants had made "a prima facie case warranting further investigation." [59]

That conclusion is particularly appropriate given the information asymmetry inherent in PJM's transmission planning process. Once OPC has made the prima facie

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[57] 163 FERC ¶ 61,113 (2018).
[58] *Id*. at P 5-6.
[59] *Id* at P 21.

showing necessary to initiate further proceedings under Section 206, the evidentiary burden shifts to PJM and the PJM TOs to respond to that showing with the information uniquely available to them. Respondents assert generally that the costs allocated under Schedule 12 correspond to regional benefits and that the challenged transmission expansion reflects multiple drivers in addition to large-load growth, but they do not identify the relative contribution of those drivers or quantify the benefits they contend Maryland receives. The analyses underlying PJM's transmission planning and cost allocation are complex and cannot be replicated by outside parties without access to PJM's models, assumptions, and project-level data. As Nelson and Eiden point out, PJM and the TOs retain the data to conduct more detailed system impact studies.[60]

PJM and the PJM TOs are therefore uniquely positioned to identify the extent to which large-load growth, as compared with other system needs, drove the transmission expansion at issue. Having made a supported prima facie showing, OPC should not be required to produce information that resides principally in respondents' hands before the proceeding may go forward. Rather, respondents should now be required to produce the evidence necessary to test their assertions—for example, analysis identifying system costs with and without the incremental large-load growth and the relative contribution of the various asserted cost drivers. Such an analysis would not require replanning the transmission system; it would identify the drivers of the costs already incurred for purposes of determining whether their allocation is just and reasonable.

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[60] Attach. A (Nelson and Eiden Rebuttal Aff.) at 14-15.

The PJM TOs' related assertion that Maryland receives reliability benefits from regional transmission does not negate OPC's prima facie showing.[61] OPC alleges that Maryland customers receive "little to no commensurate benefit" relative to the costs allocated to them. Thus, even if transmission expansion needed to serve load growth in neighboring zones also improves reliability for Maryland customers, that does not prove that the costs assigned to Maryland are roughly commensurate with those benefits. The PJM TOs' generalized assertion that all users benefit from an integrated regional grid therefore does not establish that OPC failed to make a prima facie showing.

Nor does OPC's request for a re-study establish that the Complaint is deficient. The Complaint asks the Commission to find the challenged methodology unjust and unreasonable and to direct PJM to re-study, for cost allocation purposes only, the three RTEP windows to determine the proportion of transmission-system impacts caused by data center load growth. Yet, PJM itself admits that PJM's planning process does not attribute individual transmission facilities to discrete categories of load"[62] so it defies logic to require studies of OPC that PJM itself lacks. In any event, *California PUC* confirms that a prima facie showing may be sufficient even though further factual questions remain to be resolved and where the necessary information is controlled by the subject of the complaint.

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[61] PJM TO Answer at 27-28.
[62] PJM Answer at 7.

4. PJM's objections to the planning and load-forecasting claims do not support dismissal.

PJM argues that OPC's planning and load-forecasting claims should be dismissed because the Complaint does not identify a particular Tariff, Operating Agreement, CTOA, or Manual provision that is unjust and unreasonable.[63] But OPC does not allege merely that PJM violated an existing tariff provision. It challenges PJM's existing planning and forecasting practices as unjust and unreasonable.[64] Section 206 and Rule 206 permit a challenge to an allegedly unlawful practice, and Rule 206 requires the complainant to identify the challenged action or inaction and explain why it violates the applicable statutory or regulatory standard.

The Complaint does that. It alleges that PJM's large-load forecasts are subject to substantial uncertainty; that duplicative and speculative data center requests can inflate those forecasts; that PJM does not prescribe a uniform methodology for forecasting large loads; and that utilities may use differing methodologies and assumptions in translating large-load requests into expected peak demand.[65] It further supports those allegations with evidence of cancelled and reduced projects, inconsistent utility forecasts, and PJM's own acknowledgment of growing uncertainty surrounding forward load forecasts.[66] The Complaint alleges that those forecasting practices feed directly into transmission planning

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[63] PJM Answer at 31–32.
[64] Attach. A (Nelson and Eiden Rebuttal Aff.) at 37-38 ("the Complaint identified the RTEP modeling process, and the related input processes regarding how the RTEP incorporates the load forecast including large load forecasts, as "practices affecting rates." As such, the OPC Complaint did claim these were improperly applied, and because they are purported to be "practices affecting rates" they are properly situated under the OPC's Section 206 filing rights and the Commission's review authority.").
[65] Amended Compl. at 14–18.
[66] *Id*. at 32.

and can result in transmission expansion based on load that may not materialize as forecast, thus resulting in higher costs.[67]

PJM also characterizes OPC's planning claim as resting on speculation that data centers may later convert to co-located arrangements.[68] That is only one part of OPC's showing. The Complaint's challenge to PJM's forecasting practices is independently supported by the evidence described above. The Co-located Order discussed in the Complaint[69] supplies an additional reason to question whether current planning assumptions accurately reflect the future demand and operating characteristics of large loads; it is not the sole basis for the claim.

PJM's remaining objection—that OPC's proposed planning reforms are inconsistent with PJM's existing holistic RTEP process—addresses the appropriate replacement practice, not whether OPC has shown that the existing planning and forecasting practices are unjust and unreasonable.[70] Section 206 does not require a complainant to prove at the outset that its proposed replacement is just and reasonable. In *FirstEnergy Service Co. v. FERC*, the D.C. Circuit rejected precisely that "dual burden" for a Section 206 complainant, explaining that a petitioner challenging an existing rate need not establish that its proposed alternative is just and reasonable because determining the replacement is "the Commission's job—not the petitioner's."[71] *Emera Maine*

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[67] *Id*. at 40-41.
[68] PJM Answer at 31.
[69] Amended Comp. at 66, *citing PJM Interconnection LLC*, 193 FERC ¶ 61,217 (December 18, 2015) ("Co-location Order").
[70] PJM Answer at 32–33.
[71] *First Energy Serv. Co. v. FERC*, 758 F.3d 346, 353.

likewise describes Section 206's dual burden as requiring the Commission first to find the existing rate unlawful and then to determine a just and reasonable replacement.[72]Thus, whether OPC's proposed planning reforms are ultimately adopted, modified, or rejected does not provide a basis to dismiss OPC's challenge to PJM's existing planning and load-forecasting practices.

B. The Show Cause Order does not moot the Complaint.

OPC's Complaint is not subsumed or mooted by the Commission's June 18, 2026 PJM Large Load Integration Show Cause Order in Docket No. EL26-67 (the "Show Cause Order")[73] or the proceeding commenced pursuant to that Order, even though several issues raised in OPC's Complaint may be advanced through the Show Cause proceeding. First, OPC's Complaint directly challenges PJM's existing transmission cost-allocation methodology for regional baseline transmission projects driven by large-load and data center growth and seeks relief directed to that regional cost allocation. Second, OPC's Complaint seeks a refund effective date and associated refund and rebilling relief with respect to the regional cost-allocation methodology challenged in this proceeding. Neither matter is fully addressed by the Show Cause Order.

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[72] *Emera Me. v. FERC*, 854 F.3d 9, 24–25 (D.C. Cir. 2017).

[73] *PJM Interconnection, LLC et al.*, 195 FERC ¶ 61,211 (June 18, 2026).

1. The Complaint and Show Cause Order cover different transmission projects, and dismissal of the Complaint would leave $22 billion in capex for regional baseline projects unaddressed.

Although both the OPC Complaint and the Show Cause proceeding overlap in their focus on protecting consumers from bearing transmission-infrastructure costs driven by large-load and data center growth, they differ in a critical respect. OPC's Complaint directly addresses regional baseline transmission projects and PJM's methodology for allocating the costs of those projects. The Show Cause Order, by contrast, is principally directed to Supplemental Projects and other locally planned Network Upgrades. Indeed, the Commission expressly stated that its preliminary finding "is not intended to alter or call into question existing regional cost allocation methods for Network Upgrades."[74] Moreover, the minimum cost recovery agreement that the Show Cause Order calls for, which would be based on the level of jurisdictional transmission service (in MW) requested and consequently the methods that PJM uses to study the new large load.[75] Thus, the regional baseline cost-allocation issues raised in OPC's Complaint fall outside the scope of the Show Cause proceeding and remain to be resolved in EL26-63.

The Show Cause Order itself recognizes that large-load growth may create both regional and local transmission needs. It acknowledges that large-load growth may trigger a regional transmission project in the RTEP subject to PJM's regional cost-

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[74] Show Cause Order, P 82.

[75] Attach. A, (Nelson and Eiden Rebuttal Aff.) at 8, citing Show Cause Order at para 83. ("That figure is in turn tied to how PJM and/or Transmission Owners will study the requested transmission service and determine any necessary Network Upgrades that must be developed to provide the requested transmission service.")

allocation methodology, and that Network Upgrades may either be designated as local transmission facilities, including Supplemental Projects, or contribute to regional transmission-system need. Moreover, the minimum cost recovery agreement that the Show Cause Order calls for, which would be based on the level of jurisdictional transmission service (in MW) requested and consequently the methods that PJM uses to study the new large load[76] is addressed by a Required Transmission Enhancement in the RTEP.[77] Thus, the Commission was plainly aware that large-load growth may result in regional as well as local transmission investment.

Nor is the term "Network Upgrades" itself, discussed in the Show Cause Order, limited to Supplemental Projects or other locally planned facilities. The PJM Tariff broadly defines Network Upgrades as modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System. Thus, the distinction between local and regional projects arises not from the definition of Network Upgrades, but from the Commission's express decision to

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[76] Show Cause Order at para 83. ("That figure is in turn tied to how PJM and/or Transmission Owners will study the requested transmission service and determine any necessary Network Upgrades that must be developed to provide the requested transmission service.")

[77] Show Cause Order P 22 (in relevant part, describing PJM's existing requirement that an Eligible Customer pay for Network Upgrades necessary to accommodate its New Service Request); P 27 ("In some instances, an aggregation of large loads, coupled with other drivers, could trigger regional (as opposed to local) transmission system needs, which would be identified and addressed by a regional transmission project in the RTEP, which is subject to PJM's regional cost allocation method. For example, a transmission owner may identify a local transmission need that may be more efficiently or cost-effectively addressed by a regional transmission project identified in the RTEP."); P 72 ("As discussed above, Network Upgrades needed to accommodate a new transmission service request or designation of new network load may be designated as local transmission facilities (i.e., Supplemental Projects) or contribute to regional transmission system needs and be addressed by a Required Transmission Enhancement in the RTEP. PJM's Tariff Schedule 12 Appendix and Appendix A include the cost responsibility assignments for regional transmission projects selected through the RTEP process.").

limit the operative preliminary findings in the Show Cause proceeding to Network Upgrades evaluated through the local transmission planning process.[78]

Yet the Show Cause Order does not extend its findings to the allocation of costs for those regional projects. Paragraph 74 limits the Commission's preliminary transparency finding to Network Upgrades "evaluated in the local transmission planning process," and footnote 166 states expressly that the Commission's concern with transparency "is limited to Network Upgrades planned through the local transmission planning process."[79] Paragraph 82 is even more explicit: the Commission states that its preliminary finding "is not intended to alter or call into question existing regional cost allocation methods for Network Upgrades."

The regional cost-allocation issue left outside the Show Cause proceeding is substantial and material. The Synapse analysis attached to OPC's Amended Complaint reports that, from 2010 through 2030, PJM-wide regional baseline capital costs averaged approximately **$3 billion per year**, compared with approximately $3.3 billion per year in local project spending. PJM's RTEP data show approximately $32 billion in baseline projects under construction or active as of year-end 2025, roughly equal to the approximately $32 billion in Supplemental Projects in those same categories.[80] Regional

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[78] PJM OATT, Definitions ("'Network Upgrades' shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.").
[79] PJM OATT, Definitions: "'Network Upgrades' shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include: (i) Direct Connection Network Upgrades . . . [and] (ii) Non-Direct Connection Network Upgrades . . . ."
[80] PJM 2025 RTEP, p. 350, Figure 5.2 (showing $27.2 billion in capex for baseline projects (2023-2025 RTEP cycles vs. $19 billion in capex for supplemental projects for the same cycles).

baseline investment therefore represents a category of transmission spending, in recent periods greater in magnitude than the local projects addressed by the Show Cause proceeding.[81]

There are other consequences to the Show Cause Order's narrow reach to just supplemental projects. In fact, the Show Cause Order's policy recommendations counsel a coordinated and consistent review of both regional baseline and supplemental projects. As Nelson and Eiden explain, the complexity of the cost allocation issues within PJM requires addressing *both* supplemental and regional projects to avoid creating gaming and other issues.[82] For example, only using supplemental projects may create perverse incentives for transmission owners to avoid certain requirements and study requirements or create a preference for avoiding baseline projects.[83] Moreover, regional baseline project cost allocation must be addressed, otherwise the cost shifting of data center driven infrastructure costs to ordinary households in violation of the Ratepayer Protection Pledge and a premise of the Show Cause Order will not be properly addressed.

Accordingly, if OPC's Complaint is dismissed as moot, PJM's existing methodology for allocating large-load-driven costs within this accelerating annual level of transmission capital expenditure category, approaching $7 billion-per-year of regional

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[81] *See* PJM Interconnection, L.L.C., 2025 Regional Transmission Expansion Plan (Apr. 17, 2026), at 349–50, figs. 5.1–5.2 (showing approximately $32 billion in baseline projects and approximately $32 billion in Supplemental Projects categorized as active or under construction as of December 31, 2025, and approximately $27.2 billion in committed baseline capital expenditures compared with $19 billion in Supplemental Project capital expenditures arising during the 2023–2025 RTEP cycles).
[82] Attach. A (Nelson and Eiden Rebuttal Aff.) at 7-8.
[83] *Id*.

baseline investment will remain unchallenged**.** The Show Cause proceeding may address cost shifting associated with locally planned Network Upgrades, but it expressly leaves existing regional cost-allocation methods undisturbed. OPC's Complaint addresses that remaining issue by seeking to allocate large-load-driven regional expansion costs to the zones in which the large loads and data centers are located and, as appropriate mechanisms are developed, ultimately to the Eligible Customers responsible for those loads.

OPC's Complaint directly addresses the issues affecting regional baseline projects that the Show Cause proceeding does not touch. Proceeding with EL26-63 will permit the Commission to address those issues consistent with its stated objective of preventing cost shifting and with governing transmission cost-allocation principles.

2. The Show Cause Order's refund effective does not substitute for the refund relief sought here.

OPC's Complaint also requests establishment of a refund effective date and the refund and rebilling of amounts previously charged to consumers that, depending on the Commission's determination in this proceeding, do not conform to the cost-allocation methodology ultimately determined to be just and reasonable.

The Show Cause Order also establishes a Section 206 refund effective date, but that does not make the refund relief requested in EL26-63 duplicative. The refund effective date established in EL26-67 applies to whatever tariff provisions or practices the Commission ultimately determines to be unjust and unreasonable in that proceeding. As discussed above, however, the Commission expressly stated that EL26-67 is not intended to alter or call into question existing regional cost-allocation methods. The EL26-67 refund provision therefore does not substitute for the refund protection sought in connection with OPC's separate challenge to PJM's regional cost-allocation methodology.

Moreover, the Commission has indicated that the reforms resulting from the Show Cause Order proceeding are intended to operate prospectively and without disrupting existing commercial arrangements.[84] OPC's Complaint, by contrast, seeks refund and rebilling relief associated with the particular regional baseline cost allocations challenged in EL26-63. Thus, the remedial issues raised by OPC's Complaint likewise are not subsumed by EL26-67.

3. Respondents' arguments on mootness are easily distinguished.

The PJM TOs argue that the Complaint is moot because the Show Cause Order addressed the Complaint's concerns with cost shifting associated with large-load growth and established principles that will govern the replacement rate which displace OPC's proposed regional remedy.[85] But the PJM TOs ignore that the Show Cause Order does not disturb PJM's existing regional cost-allocation methodology that OPC challenges in EL26-63. Given that the Show Cause Order declined to alter or call a rate methodology

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[84] See Show Cause Order P 38 (directing that proposals account for existing commercial arrangements and identify a reasonable effective date accommodating those arrangements); see also Show Cause Order P 5 (explaining that the proceeding is intended to establish prospective reforms rather than disrupt existing commercial arrangements).
[85] PJM TOs at 21-22.

into question, the PJM TOs cannot argue that the order simultaneously moots a complaint challenging that same methodology.

The PJM TOs reliance on *CPV Power Holdings, L.P. v. PJM Interconnection, L.L.C.*[86] is misplaced. There, the Commission dismissed the complaint only after it had already "addressed the very issue raised in [the] [c]omplaint" in an earlier order, finding the challenged rate unjust and unreasonable; had subsequently established the principles governing the just and reasonable replacement rate; and had exercised its discretion not to order refunds for the period covered by the complaint.[87] The Commission further explained that any challenge to the replacement remedy belonged in the proceeding in which that remedy had been ordered.

None of those circumstances is present here. The Show Cause ruling did not adjudicate OPC's challenge to PJM's existing regional cost-allocation methodology, did not establish a replacement rate for that methodology, and expressly states that its preliminary findings are not intended to alter or call existing regional cost-allocation methods into question. Thus, unlike *CPV*, the "very issue" raised in OPC's Complaint remains unresolved.

Sierra Club v. Southwest Power Pool, Inc.[88] is distinguishable for the same reason. There, the complaint challenged SPP's then-effective resource-accreditation methodologies. While the complaint was pending, the Commission accepted new

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[86] 171 FERC ¶ 61,036 (2020)
[87] *Id*. at P 10.
[88] 193 FERC ¶ 61,207 (2025).

methodologies that completely replaced the challenged methodologies, and subsequently found the new methodologies just and reasonable. The Commission therefore dismissed the complaint because "the resource accreditation methodologies that were the target of the Complaint are no longer effective."[89] Here, by contrast, PJM's regional cost-allocation methodology which is the target of OPC's Complaint remains effective**,** and the Show Cause Order expressly leaves that methodology undisturbed.

ODEC and SMECO also seek dismissal or abeyance based on the pendency of EL26-67. ODEC argues that the issues raised by the Complaint are now pending in the Show Cause Order proceeding and that addressing them there would avoid duplicative proceedings and permit development of a more complete record.[90] SMECO similarly argues that, to the extent the two proceedings overlap, continuing both would create duplication and risk inconsistent outcomes.[91] But neither argument establishes mootness because the Show Cause Order proceeding expressly leaves the regional cost-allocation methodology challenged here undisturbed. Indeed, SMECO itself limits its requested dismissal only to the extent the Complaint duplicates the Show Cause Order and acknowledges that OPC may pursue relief not addressed there.[92]

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[89] *Id*. at P 14.
[90] ODEC Answer at 7-9. In addition, ODEC's reliance on *California Independent System Operator Corp.*, 133 FERC ¶ 61,224 at P 62 (2010), is misplaced. There, the Commission declined to initiate a Section 206 investigation because the requesting party had not provided sufficient factual evidence or legal justification to challenge the existing tariff provisions. After finding the party failed to support its case, the Commission then added that the same issue was already being evaluated in a pending rulemaking and declined to duplicate those efforts. By contrast here OPC has offered sufficient information for the Commission to act on the complaint.
[91] SMECO Answer at 7-8.
[92] PJM notes that the Show Cause Order will address several issues raised in OPC's Complaint but does not seek dismissal on those grounds. PJM Answer at 4 and n. 12.

C. Respondents' remaining grounds for dismissal fail.

1. PJM should not be dismissed as a Respondent.

PJM argues that it is not a proper respondent to OPC's cost-allocation claims because, under *Atlantic City*,[93] the PJM TOs possess the exclusive Section 205 filing rights over transmission rate design, including Schedule 12.[94] PJM also relies on Commission decisions dismissing RTOs or ISOs where they merely administered a transmission owner's rate and the transmission owner was the true party in interest.[95]

But the Commission's Show Cause Order demonstrates that the Transmission Owners' Section 205 rights do not require PJM's dismissal from a Section 206 proceeding. There, the Commission directed both PJM and the Transmission Owners to show cause why the PJM Tariff remains just and reasonable, while expressly preserving their respective filing rights by directing each to respond "to the extent the matters addressed herein implicate aspects of the Tariff over which they have the filing rights."[96] And PJM itself cites *RENEW Northeast, Inc. v. ISO New England Inc.*,[97] where the Commission retained ISO-NE as a respondent to ensure that the entities needed to implement any resulting Tariff changes remained parties to the proceeding.[98] The same consideration applies here given that OPC separately challenges PJM's own RTEP planning and forecasting practices.

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[93] *Atlantic City v. FERC*, 295 F.3d. 1 (D.C. Cir. 2002).
[94] PJM Answer at 8–10.
[95] *Id.* at 10 & n.31
[96] Show Cause Order at P 38.
[97] 189 FERC ¶ 61,216 (2024).
[98] PJM Answer at 11 n.32.

2. OPC's requested relief does not intrude on state retail jurisdiction.

The Transmission Owners argue that OPC's requested relief would entangle the Commission in matters reserved to the states by effectively identifying particular retail customers that must bear transmission costs, displacing state large-load tariffs and negotiated arrangements, and overriding state economic-development choices.[99] But the Commission's Show Cause Order draws the federal-state line differently. The Commission recognized that large-load integration implicates both federal and state interests, while holding that certain aspects "fall squarely within the Commission's exclusive jurisdiction," including tariff provisions governing how transmission service to large loads is studied and whether new or upgraded transmission facilities are necessary to provide that service.[100] It further held that the Commission has exclusive jurisdiction over the rates, terms, and conditions of interstate transmission service to large loads and explained that the study process determines the Network Upgrades required to serve those loads, whose costs are included in Commission-jurisdictional transmission rates.[101]

The Show Cause Order separately confirms that transmission-level cost shifting is a federal concern. The Commission held that it has a "duty to address the risk of cost shifting among transmission customers" and "exclusive authority to ensure that transmission rates are just and reasonable."[102] Network Upgrade costs needed to serve

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[99] PJM TO. Answer 15-17.
[100] Show Cause Order at PP 44–45 (2026).
[101] *Id.* PP 46–49.
[102] *Id.* P 68.

large loads are inputs to jurisdictional transmission rates and therefore directly affect the rates paid by transmission customers.[103] By contrast, states determine how those Commission-approved wholesale costs are subsequently recovered from retail customers.[104] The Commission also explained that identifying transmission cost causation would assist rather than displace state regulation by providing greater transparency to allow state regulators to "sub-allocate these costs to the appropriate retail customers."[105]

One of the reasons that OPC filed the complaint is because state remedies are inadequate because states lack the jurisdiction to address cost shifting related to RTEP projects which cross state lines.[106] Other parties like Sierra Club likewise recognize that state remedies cannot correct cost shifting at the wholesale level.[107] Accordingly, OPC's proposal does not displace state tariffs but offers critical relief where state remedies fall short.

3. OPC was not required to exhaust alternative remedies before filing its Complaint.

The PJM TOs argue that OPC should have pursued state remedies, Commission ADR procedures, or PJM stakeholder processes before filing its Section 206 Complaint.[108] But the rules do not require exhaustion, and the Commission itself previously told OPC that a complaint was the appropriate vehicle for raising this

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[103] Id.
[104] *Id.* P 69.
[105] Id. at P 70.
[106] Amended Compl. at 46-48.
[107] Sierra Club Answer at 14.
[108] PJM TOs Answer at 18–21.

challenge. In *PJM Interconnection, L.L.C.*,[109] the Commission rejected OPC's effort to raise its cost-allocation concerns through a protest and expressly stated that "[t]he issues raised by the Maryland People's Counsel protest should have been filed as a complaint." In filing its Complaint initiating this proceeding, OPC did exactly what the Commission instructed.

Nor does Rule 206(b)(9)[110] impose an exhaustion requirement. It requires disclosure concerning the use of informal dispute-resolution procedures. Rule 604(a)(1),[111] which the PJM TOs themselves cite, describes Commission ADR as "voluntary procedures that supplement rather than limit other available dispute resolution techniques."[112] The PJM TOs offer no further authority to support their claim that OPC was required to take a region-wide challenge to a Commission-jurisdictional transmission cost-allocation methodology through PJM stakeholder committees, informal discussions, or state proceedings before invoking Section 206.

4. The Complaint is not an improper collateral attack.

First, OPC's short-circuit argument is not a collateral attack because the Commission has not resolved the issue OPC raises. OPC contends that solution-based DFAX is not appropriate for allocating costs associated with short-circuit violations.[113] But on remand in *Consolidated Edison*,[114] the Commission did not decide that question.

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[109] 187 FERC ¶ 61,012 at P 29 (2024).
[110] 18 C.F.R. § 206(b)(9).
[111] 18 C.F.R. § 604(a)(1).
[112] PJM TOs at 19.
[113] Amended Compl. at 37–40.
[114] *Consolidated Edison Co. of New York, Inc. v. PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,179 at PP 72–75 (2026).

Instead, the Commission found that "additional record evidence is necessary to determine whether" the existing use of solution-based DFAX for short-circuit projects is unjust and unreasonable, and established a paper hearing to determine whether short-circuit projects should be treated similarly to stability projects, for which DFAX has already been found inappropriate.[115] Because the Commission has left open the issue of whether DFAX is appropriate for allocating short-circuit project costs, OPC does not attack or seek to undo any settled Commission determination. At most, OPC's short-circuit argument presents an issue that overlaps with the pending *Consolidated Edison* proceeding; overlap with an unresolved proceeding is not a collateral attack.

Second, OPC does not attack the Commission's 2013 earlier approvals of the hybrid methodology. The Complaint expressly acknowledges that PJM's hybrid methodology was developed and approved under a fundamentally different set of conditions which did not contemplate the massive, geographically concentrated growth in data center large loads and argues that its current application has become unjust and unreasonable as those conditions have changed. When the methodology was developed, load growth was gradual, diffuse, and broadly distributed; today, massive geographically concentrated data center additions can drive billions of dollars of transmission investment in discrete areas within a few years. The Complaint further explains that historical acceptance of a cost-allocation methodology does not insulate its later application from

[115] *Id.*

Section 206 review when circumstances change, pointing both to *Artificial Island*[116] and to the Commission's large-load co-location order as examples in which an approach appropriate under one set of conditions ceased to produce just and reasonable results under another. Sierra Club independently confirms that framing: the methodology may have been reasonable when load growth was slower and more evenly distributed, but concentrated large-load growth has fundamentally changed the conditions under which it operates. Thus, the PJM TOs' assertion that "no material changes have occurred"[117] is a merits dispute over OPC's showing of changed circumstances, not a collateral-attack bar.

Third, OPC's requested re-study of the three RTEP windows does not seek to undo PJM Board approval of the projects themselves. The Transmission Owners argue that because those projects have already been approved and some associated cost allocations accepted, OPC seeks to "abrogate prior approvals."[118] PJM TOs at 36. But the relief OPC actually requests is different: OPC asks the Commission to find Schedule 12's allocation of costs for those windows unjust and unreasonable, establish a refund effective date, and direct PJM to re-study the windows to identify the proportion of transmission-system impacts caused by data center load growth and credit back costs collected after the refund effective date that are attributable to that growth.[119]

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[116] Amended Compl. at 31, citing Delaware Public Service Commission v. PJM Interconnection LLC, 164 FERC ¶ 61,035 at P 42 (2018) *aff'd sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10 (D.C. 2021)("Artificial Island").
[117] PJM TOs Answer at 35.
[118] *Id.* at 39.
[119] Amended Compl. at 7.

II. The Schedule 12 cost allocation methodology is unjust and unreasonable.

A. Respondents do not show that the load-ratio-share ("LRS") component of the PJM's tariff's cost allocation methodology is roughly commensurate with benefits under current circumstances impacted by large-load forecasts.

OPC's Complaint showed that the load-ratio-share allocation for Maryland customers for the three disputed RTEP windows accounts for $678.7 million in capital costs and $540.3 million in revenue requirements.[120] Those costs arise from expansions to serve 90 percent of PJM's forecasted large-load additions which are concentrated in just four zones: Virginia (Dominion), Ohio (AEP), Illinois (Commonwealth Edison) and Pennsylvania (PPL),[121] while Maryland's load growth remains essentially flat over the same planning horizon used to structure the RTEP procurement windows.[122]

Respondents generally do not dispute OPC's numbers. Instead, they defend load share ratio on four grounds: (1) that OPC cannot prove that Maryland derives zero benefits, (2) that the load-ratio share fairly measures the benefits Regional Facilities provide to each zone; (3) that Maryland's dependence on imported power demonstrates its benefits; and that (4) the load share ratio methodology is consistent with longstanding precedent. OPC addresses each below.

1. OPC does not need to show that Maryland receives no benefits.

PJM TOs' witness Russo faults OPC for providing "no specific examples of PJM regional baseline projects that were allocated based on load-ratio share . . . to customers

[120] Amended Compl. at 12, Tables 1–2.
[121] OPC Complaint at 13, Nelson Eiden Aff at 23-24.
[122] *Id.* at 25, 62–64.

that derived no benefits from the projects."[123] The "no benefits" formulation invokes a standard that does not apply. *Ill. Commerce Comm'n v. FERC* forbids allocation of costs to customers who derive "no benefits, or benefits that are trivial *in relation to* the costs sought to be shifted."[124] In other words, the cost-allocation inquiry is relational. A customer may benefit from a facility and still be overcharged for it. Costs may be grossly disproportionate to benefits.[125] OPC's evidence focuses on that relationship between cost and benefit: the concentration of the growth driving the expansion, the size of the charges assigned to a zone whose load is not growing, and the absence of any corresponding measure of benefit. Demanding examples of zero-benefit projects does not answer that showing; it substitutes a test that the law does not impose.[126]

2. Respondents have not shown that load share ratio measures the benefits the zone receives from the challenged facilities.

OPC argues,[127] and several intervenors concur[128] that load share ratio does not function as a rough proxy for measuring cost causation when the driver of transmission

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[123] Russo Aff. at 15.
[124] 576 F.3d 470, 477 (7th Cir. 2009).
[125] *Long Island Power v.* FERC, 27 F.4th 705, 715 (D.C. Cir. 2022). (describing precedent setting side cost allocations which were described as "grossly disproportionate").
[126] Demonstrating a commensurate benefit is a different concept from demonstrating no benefits. As Nelson and Eiden explain, with the recent and forward-looking upgrades required to serve data center loads, the question becomes do the required incremental expansions provide a commensurate benefit to other ratepayers? Because PJM does not identify and quantify the cost caused by large loads, this is likely impossible to answer, but common sense clearly suggests that ratepayers will have not and will not receive commensurate benefits from these upgrades. Attach. A (Nelson and Eiden Rebuttal Aff.) at 24-25.
[127] Amended Compl. at 35.
[128] *See* SMECO Answer at 8 (recognizing that geographically concentrated large-load growth "can create real risk that other customers will be asked to bear costs they did not cause — whether through broad load-ratio-share socialization or through stranded investment."); IL OAG at 6 ("Load-ratio share is an unjust and unreasonable method of assigning costs because it erroneously assumes that transmission projects built to serve large-load customers benefit the entire footprint but the assumption no longer holds when applied to transmission built to serve large loads"); NJ BPU 6-7 ("Under the new paradigm in

investment arises from concentrated large load growth in a discrete geographic area. In response, PJM and the PJM TOs defend load share ratio because Regional Facilities "benefit the region"[129] and capture generalized, system-wide benefits.[130] The Data Center Coalition ("DCC") relies on the presumption that improvements to an integrated transmission system confer broad regional benefits on all of its members.[131] PJM TOs' Witness Russo also adds that because the load-ratio-share allocation is recalculated annually, it "reflect[s] year-to-year changes in grid usage" and therefore "constitute[s] a measure of the benefits transmission customers in each zone realize from each RTEP project."[132]

The load-ratio share does not operate as Respondents claim. It charges each zone according to the relative size of its peak load, *i.e.*, Maryland's share of last year's PJM peak.[133] That charge matches benefits only if benefits rise and fall with load size. CEBA argues that they do: in its view, a zone's reliance on the grid at peak hours reflects its share of the benefits Regional Facilities provide.[134] But a zone's peak-load share is the same percentage for every project. It cannot reflect the benefits of any particular facility, because it does not change no matter what the facility is or does. And on this record, benefits do not rise and fall with load size: the facilities in the challenged RTEP

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which load growth is no longer approximately even over the zones, and where that load growth can be so clearly tied to a single class of customers concentrated in discrete geographical areas, a load ratio share approach based on existing load may no longer be appropriate.")

[129] PJM Answer at 23–25.

[130] PJM TO Answer at 23–28.

[131] DCC Protest at 10–12

[132] Exh, PJMTO-001 (Russo Aff.) at 8.

[133] Amended Compl. at 19, Attach A (Nelson and Eiden Aff.) at 40 & n.75.

[134] CEBA Comments at 8–10, 12–13.

Procurement windows were built because load is growing in four zones, and Maryland's forecasted load growth is flat.[135] Yet Maryland is charged $678.7 million in capital costs for those facilities, an amount fixed by the size of its load, not by anything its customers caused or gained.[136]

The Commission itself recognized the shortcomings of peak load usage as a basis for cost allocation in its recent Co-Located Order.[137] As Nelson and Eiden explain, the Commission took issue with PJM's tariff for not having adequately explained how an Eligible Customer taking service on behalf of a co-located large load would pay for their fair share of various uses of the transmission system.[138] Critically, this failure and shortcoming is contemplated *precisely because of the inability of cost allocation methods based on peak load usage of the system* to reflect a just and reasonable cost allocation.[139]

Russo's annual-update point[140] does not rescue the method. The update recalculates Maryland's load share each year, but that does not fix the problem if load share does not measure benefits or fails to materialize.[141]

Charging by load size tracks benefits when load grows roughly uniformly across all zones, because every zone's size, over time, roughly matched its share of the need for new facilities. But today, "the load-ratio share allocator no longer functions as a rough

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[135] Amended Compl. Attach. A (Nelson and Eiden Aff. at 25, 62–63.
[136] *Id.*
[137] *PJM Interconnection LLC*, 193 FERC ¶ 61,217 (2015).
[138] *Id.* at P 4, P 9, P 10.
[139] Attach. A (Nelson and Eiden Rebuttal Aff.) at 22.
[140] Russo Aff. at 8.
[141] Attach A (Nelson and Eiden Rebuttal Aff.) at 41 (explaining that updating cost allocation information does not overcome the problem of inflated load estimates which will be shared among other zones even if they do not materialize).

proxy" for benefits.[142] PJM itself concedes that whether circumstances have changed "is a decision that [the Commission] must make in this proceeding."[143]

3. Maryland's import dependence shows reliance on the existing regional system, not benefits commensurate with the charges for incremental RTEP 2022/3, 2024 and 2025 Transmission Facilities.

Respondents rely heavily on Maryland's status as a net importer. PJM states that Maryland imports approximately 40 percent of its energy needs and that Maryland and the District of Columbia are among the largest importers during peak system conditions.[144] The PJM TOs and Russo present the same point, supported by a chart showing that Maryland imported energy in nearly all hours of 2025.[145] DCC adds congestion data for the BGE zone, and CEBA argues that Maryland's proximity to Virginia means that new transmission in neighboring areas increases Maryland's flexibility during contingencies.[146] The PJM TOs also point to the Brandon Shores deactivation, whose mitigation projects were allocated regionally without objection from OPC.[147]

The comparison of unprecedented, forecasted increases in large loads, comprising cumulatively 38 GW with the 2025 RTEP Window 1 planning cycle to the Brandon Shores power plant deactivation is irrelevant and misses the mark. Brandon Shores is a

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[142] Amended Compl. at 35–36
[143] PJM Answer at 26.
[144] *Id.* 25–26.
[145] PJM TOs at 27.
[146] DCC Protest at 15; CEBA Comments at 14.
[147] PJM TOs Answer at 27, 29.

generator that was separately identified as a project driver for an RTEP solution with a unique set of project numbers, developed under a decades-old framework for a foreseeable event of generation deactivation.[148] Large loads have no framework, no comparable studies, and no such precedent and create numerous unprecedented challenges that must be addressed to maintain affordability for other customers.[149]

At most, Maryland's import dependence merely shows that Maryland receives benefits from the regional transmission system that customers pay for through network service. It does not show that Maryland receives benefits from the challenged incremental facilities commensurate with the charges the load-ratio-share component assigns for them. The frequency of Maryland's imports, which is what the Russo chart depicts, says nothing about whether the projects selected in the three challenged RTEP windows increase transfer capability into Maryland, relieve constraints affecting Maryland's imports, or resolve violations affecting Maryland load.

There are additional reasons to ignore respondents' framing of the Brandon Shores retirement as a Maryland policy choice that somehow justifies allocating to Maryland over a billion dollars in data center driven transmission costs. As Nelson and Eiden explain,[150] Brandon Shores was closed due to the plant owner's (Talen's) assessment that retirement was economically preferable given existing and forecasted PJM market conditions affecting the economics of operating the plant, PJM and not Maryland is

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[148] Attach. A (Nelson and Eiden Rebuttal Aff.) at 33-34.
[149] *Id.*
[150] *Id.* 33-34.

responsible for maintaining grid reliability and the power flows allocated by DFAX for transmission are not the same as those flows involved in import export balance.[151] Moreover, over 65 percent of the allocation of the cost of the Brandon Shores and Wagner power plant deactivations transmission mitigation projects is to the BGE and PEPCO zones; for Brandon Shores alone, more than 85 percent is allocated to the BGE and PEPCO zones.[152] OPC does not challenge that allocation here. It is inapt, as do some of the respondents, to assert that Maryland lacks "standing" to contest the allocation of transmission costs from the three RTEP windows due to projects for which Maryland customers are supporting the majority of the costs, and targeted at the reliability issues arising from power plant deactivations, addressing them separately from the RTEP procurements.

4. The Commission's prior approvals are no longer relevant since they rest on conditions that no longer exist.

Finally, respondents argue that Commission's prior approvals of the load-ratio-share component and the hybrid methodology justify its continued use. PJM argues that "[t]he emergence of data centers changes the source of load growth" but not the Commission's cost-allocation principles, and that the "fundamental premise" of the prior

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[151] *Id.*

[152] *See*, PJM, *Zonal Cost Allocation for Retaining Brandon Shores 1 & 2 Generators (undated); PJM, Zonal Cost Allocation for Retaining Wagner 3 & 4 Generators (undated).* The Brandon Shores transmission mitigation project capex (allocated 82.8% to the BGE and PEPCO zones) increased from its initial estimate of $735 million to approximately $1.5 billion, the current estimate. The combined capex for the transmission mitigation projects for both generator deactivations is $2.185 billion. DCC's assertion that over 44% of the cost of the transmission upgrades triggered by these de-activations is allocated to non-Maryland customers is in error. DCC Protest at 8.

orders remains.[153] The PJM TOs argue that the premise that all users of an integrated system benefit from system upgrades "continues to hold true today."[154] DCC contends that the prior approvals were never premised on any assumption about the geographic uniformity of load growth, and CEBA observes that the hybrid methodology itself emerged from the *Illinois Commerce Commission* litigation and allocates only half of the applicable costs through load-ratio share.[155] Respondents add that the Commission has never required benefit quantification with exacting precision.

OPC does not quarrel with these general cost allocation principles. But the context matters. As the Seventh Circuit recognized, "[T]he fact that these utilities thought it appropriate to share costs in 1967 says nothing about the advantages and disadvantages of such an arrangement in the larger, modern PJM network."[156] Compliance with Order No. 1000 likewise does not "necessarily ensure compliance with the cost-causation principle."[157] PJM concedes that whether circumstances have changed "is a decision that [the Commission] must make in this proceeding."[158]

The history of the LRS methodology confirms that adjustment of its components has been altered to better address changed conditions. PJM formerly allocated 100 percent of the costs of facilities operating at or above 500 kV by load-ratio share. That approach did not survive review once transmission expansion concentrated in eastern

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[153] PJM Answer at 24–25.
[154] PJM TOs Answer at 31.
[155] DCC Protest at 10; CEBA Comments at 13–14.
[156] *Ill. Commerce Comm'n,* 576 F.3d at 475.
[157] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1263 (D.C. Cir. 2018).
[158] PJM Answer at 26.

PJM, and the hybrid methodology (with its load-ratio-share component reduced to 50 percent) was introduced in response.[159]

DCC argues that the Commission's earlier approvals never assumed load growth would be spread evenly across PJM so there is no reason to change them.[160] But the history of the LRS methodology says otherwise. PJM originally charged the entire cost of high-voltage facilities by load-ratio share. FERC cut that share in half, to today's 50/50 hybrid, specifically because growth had concentrated in eastern PJM and the old formula was overcharging the west for it. Geography is exactly why the formula changed last time—DCC's claim that geography was never a factor doesn't hold up against that history.

Moreover, "the Commission has said directly that it does not treat this formula as fixed. When a transmission owner argued that an earlier order locked PJM into a single method, FERC responded that the order "should not be construed as preventing PJM and its stakeholders from developing other cost allocation methodologies."[161]

Two other parties make the same point. The IL OAG traces the same 2013 history and concludes that the assumption behind it—that "everyone benefits from high-capacity transmission facilities because they increase the reliability of the entire network"—"no longer holds when applied to transmission built to serve large loads."[162] The NJBPU

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[159] *Ill. Commerce Comm'n,* 576 F.3d at 475–78; *Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 561 (7th Cir. 2014).
[160] DCC Protest at 10.
[161] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, PP 432–33 (2013) (quoting *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230, P 2 (2012)).
[162] IL OAG Comments at 6 (quoting *Ill. Commerce Comm'n,* 576 F.3d at 474).

goes further, devoting a section of its comments to the conclusion that "it is appropriate and necessary, under the cost causation principle, to revisit PJM's current cost allocation methods given the changed circumstances driving future transmission needs."[163] Like OPC, both IL OAG and NJBPU ask that the Commission recognize that the premise underlying the load-ratio-share component no longer describes the system to which it is being applied.

The cases respondents cite that FERC may continue to rely on LRS to allocate generalized, non-project-specific benefits are distinguishable. In *Long Island Power Authority v. FERC*, the D.C. Circuit upheld extending PJM's hybrid formula to older, already-built projects, but only because there was no evidence that the Vintage Projects were any different from other high-voltage transmission facilities within PJM and therefore entitled to different treatment.[164] By contrast here, the RTEP facilities are different from their predecessors because they are driven by load growth concentrated in four zones that was not contemplated when the LRS methodology was approved.[165] Respondents' remaining precedents presented scenarios where costs were roughly commensurate with benefits unlike here.[166]

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[163] NJBPU Comments at 1, 6.
[164] 27 F.4th 705, 715 (D.C. Cir. 2022).
[165] Amended Compl. Attach A (Nelson and Eiden) Aff. at 25, 62–64
[166] See *Nebraska Pub. Power Dist. v. FERC*, 957 F.3d 932, 940–41 (8th Cir. 2020) (upholding a disputed $4.3 million cost shift because the record supported an articulable and plausible finding that the benefits of a 40-year integrated relationship were roughly commensurate with the costs allocated); *Paragould Light & Water Comm'n v. FERC,* 144 F.4th 287 D.C. Cir. July 11, 2025) (upholding a $1.8 million cost allocation because FERC found integration and reliability benefits roughly commensurate with that cost); *Municipal Energy Agency of Nebraska v. FERC*, No. 25-1086 & 25-1111, slip. op. at 8-12 (D.C. Cir. June 9, 2026) (per curiam) (unpublished) (partially denying in part a challenge to a rate adjustment for an integrated transmission network project where FERC found that affected customers would receive

B. The presence of other transmission drivers does not rebut OPC's showing that large-load growth is a major driver of the challenged expansion.

Respondents' next argument is that data centers are neither the sole nor primary driver of RTEP transmission projects. PJM explains that it plans "holistically," accounting for generation retirements and shifting market conditions, and that data center load growth "may be one factor of today's drivers."[167] The PJM TOs argue that the RTEP addresses needs beyond load growth, pointing to Maryland's generator deactivations and import dependence.[168] DCC notes that the recent windows respond to some 11 GW of generator deactivations, offshore wind delays, and reactive power needs, not data centers alone.[169] From these premises, PJM concludes that the contribution of large loads is not "identifiable" or capable of being distinguished from other drivers and therefore cannot serve as a basis for cost allocation.[170]

The respondents' own admissions belie their arguments that there are multiple reasons for the expansion projects and that this negates the singular importance and impact of forecasted data center load growth and its "identifiable" characteristics. Respondents all concede that data centers drive increased demand for energy and RTEP

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reliability, resilience, economic, reserve reduction, and generation access benefits). Each case rests on a finding that the benefits were roughly commensurate with the costs allocated. That finding is foreclosed by the record here because costs assigned by load share ratio bears no relationship to the facilities driving the challenged RTEP windows.

[167] PJM Answer at 12, 23.

[168] PJM TOs Answer at 27-29; Russo Aff. at 17–18.

[169] DCC Protest at 8.

[170] PJM Answer at 12, 23.

upgrades.[171] Data centers are also an identifiable cause. For the 2025 RTEP Window 1, PJM's reliability analysis identified substantial data center load in the AEP, PPL, and Dominion zones as the "high-impact drivers" of the 2030 and 2032 models.[172] PJM's Board has stated that of the 32 GW of peak load growth it projects by 2030, approximately 30 GW is attributable to data centers—a system-wide attribution that bears on all three challenged windows, not 2025 RTEP Window 1 alone. Complaint at 13–14; Nelson/Eiden Aff. at 24, 26. Project-level attribution is feasible as well. Dominion's own integrated resource plan likewise lists 88 transmission projects driven primarily by data center connections and 37 more attributed to multi-driver load growth, with capital costs between $2.44 billion and $5.77 billion.[173]

The other drivers respondents cite do not change this. For example, DCC's reference to 11 GW of generator deactivations[174] is dwarfed by the 38.9 GW of large-load additions by 2032, and deactivations are spread across the footprint while over ninety per cent on average over the three RTEPs of the large load additions concentrate in four zones. And even accepting that several drivers contribute at once, the answer is to

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[171] *See e.g.*, PJM Answer at 24 ("there is no doubt that data center and other large load additions are causing increased demand for electricity, leading to increased costs to construct more Regional Facilities."); PJM TOs Answer at 30 ("Now the expansion appears driven by interconnecting large loads." Russo Aff. at 17 ("large load growth is an important driver of recent RTEP upgrades."); CEBA Comments at 6 ("large loads are certainly driving the need for and benefiting from regional transmission facilities."); ODEC Answer at 5-6 (large loads, "predominantly data centers, are the primary driver of the unprecedented growth in electricity demand," and PJM's RTEP "includes unprecedented amounts of transmission facilities . . . as necessary to serve large loads."); SMECO Answer at 2 (attributing the affordability and reliability pressures on its members to "massive load growth caused by large loads.").
[172] Amended Compl. at 13, Attach A (Nelson and Eiden Aff.) at 25–26.
[173] Id at 12–1, Attach A (Nelson and Eiden Aff.) at 23–24.
[174] DCC Answer at 8.

determine their relative contribution which is part of the re-study OPC requests,[175] not to ignore complaints about cost allocation because more than one cause exists.

C. Respondents have not shown that DFAX adequately allocates costs associated with Large-Load-Driven reliability needs.

The solution-based DFAX method allocates a project's costs according to the power flows the project carries: it models the transfer of power from PJM generation to each zone and assigns cost responsibility based on each zone's share of the flows over the new facility.[176] In the Complaint, OPC argues that solution-based DFAX is unjust and unreasonable for at least two reasons. First, as the Commission itself has recognized, [177] DFAX allocates costs according to power flows, and for reliability needs that are not power-flow problems (short-circuit duty, [178] reactive power and voltage support, stability), a flow-based allocator does not identify the customers who cause or benefit from the project.[179] Second, because DFAX's cost shares are recalculated annually using current load rather than the original forecast that justified the project, a transmission owner faces no cost consequence when a forecasted large load fails to materialize; the

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[175] Amended Compl. at 69.
[176] Amended Compl. At 19-20, Attach A (Nelson and Eiden Aff.) at 40–41 (citing OATT Sched. 12, § (b)(iii)(B)); Complaint at 19–20.
[177] *Del. Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,234 at P 7 (2018) *aff'd sub. nom. Pub Serv. Elec. & Gas Co. v. FERC,* 989 F. 3d 10, 18 (D.C. Cir. 2021)(affirming FERC finding on remand that DFAX doesn't apply to stability-related reliability) *see also* Amended Comp. at 20, 36–37.
[178] In *Consolidated Edison v. FERC*, 45 F.4th 265, the D.C. Circuit found that the Commission failed to explain why solution-based DFAX applied to projects addressing short circuit reliability which the court viewed as similar to the stability projects in *Artificial Island* for which SBDFAX was found inappropriate. The case was remanded to the Commission which established a paper hearing to obtain evidence regarding the application of solution-based DFAX to short circuit reliability violations. *See Consolidated Edison*, Order on Remand, 194 FERC ¶ 61,179 (2026) at P 74.
[179] Amended Compl. at 33, 36–37.

annual update instead shifts the project's costs onto zones that had no part in creating the need.[180]

Other parties concur. IL OAG states that it "agrees with both criticisms"—that solution-based DFAX "does not capture the benefits to stability that these transmission projects can provide" and that it "is undermined by load that fails to materialize."[181] IL OAG adds that "[s]peculative load and stranded assets have a high potential to drive costs in other zones due to solution-based DFAX," citing an industry estimate of "five to ten times more interconnection requests than data centers actually being built" and the Commission's own acknowledgment, in the show-cause proceeding addressing large-load interconnection costs, that when "the Eligible Customer takes less transmission service than anticipated ... transmission customers may see an increase in transmission rates."[182] The NJBPU documents the same forecast-reliability problem already occurring in the RTEP cycle at issue here: the load forecast PJM used to justify 2025 RTEP Window 1 projects showed a decrease in expected peak load for nearly every New Jersey zone compared to the forecast used just one planning cycle earlier, after New Jersey ratepayers had already been allocated $517 million in load-ratio-share costs tied to the higher, since-revised figure.[183] Both IL OAG and NJBPU ask the Commission to revisit the cost allocation methodology.

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[180] *Id.* at 37–40, Attach. A (Nelson and Eiden Aff.) at 53–56.
[181] IL OAG Comments at 7.
[182] *Id*. at 7 (quoting Show Cause Order at P 52).
[183] NJBPU Comments at 5.

1. DFAX is unjust and unreasonable because it measures flow and not non-flow based reliability needs caused by data centers.

Respondents do not dispute that solution-based DFAX allocates costs according to power flow rather than according to non-flow reliability needs. They argue instead that this flow-based measure is nonetheless an adequate proxy for those needs, that precedent and a pending proceeding leave the question undecided in their favor, and that the specific costs at issue in the 2022 RTEP W3 window were correctly allocated regardless. None of these responses have merit.

2. Solution-Based DFAX is unjust and unreasonable because it allocates costs based on power flow, not the non-flow reliability needs that large loads create.

Russo argues that SBDFAX is not, as OPC describes it, a method "designed to allocate costs associated with thermal and static voltage violations identified through steady-state power flow analysis."[184] As Russo explains, DFAX "estimates beneficiaries based on relative usage," consistent with the Commission's beneficiary-pays principle.[185] PJM and CEBA offer a related but different response: to the extent SBDFAX does not capture non-flow benefits, load-ratio share is the component of the hybrid method built to capture them.[186]

DCC goes further, arguing that stability-driven facilities are allocated under a separate tariff provision—the Stability Deviation Method, Sched. 12(b)(xviii)—not DFAX at all, and that the 2022 W3 drivers were "reliability violations stemming from

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[184] Russo Aff. at 10.
[185] *Id*
[186] PJM Answer at 21.

load flow analysis, not short-circuit analysis."[187] CEBA separately argues that *Artificial Island* is distinguishable because it addressed one isolated stability project, while RTEP evaluates portfolios of projects that together address both flow and non-flow needs. Viewing any one project alone, CEBA says, "misses the forest for the trees."[188]

The fact that non-flow stability-related projects are only required to support projects selected to address flow-based constraints does not mean that this practice is just and reasonable. As stated by CEBA's expert witness, these projects are lumped together because "[I]dentifying beneficiaries based on flow is therefore appropriate because the beneficiaries are not the same beneficiaries you would identify if a non-flow project arose outside of RTEP."[189] In other words, the way PJM is allocating costs for non-flow related projects within RTEP differs from the method it uses to allocate costs for the same type of violations outside of RTEP, as in the case of the *Artificial Island* ruling which pertained to a generator seeking interconnection to the grid.[190] This discrepancy underscores OPC's claims that this practice leads to unjust and unreasonable outcomes given how closely data center operations mirror generators in terms of system impacts.[191] Bundling them together in this way simply obscures the true cost causer and by CEBA's own admission the benefits of the project will be borne by other beneficiaries.

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[187] DCC Protest at 16–17.
[188] CEBA Comments at 15–16.
[189] CEBA Answer, Affidavit of Jay Caspary at 12.
[190] *Pub. Serv. Elec. & Gas,* 989 F.3d 10.
[191] *See e.g.*, Amended Comp., Attach. A (Nelson and Eiden Aff) at 65 (noting similarities between generation and large load).

Respondents also argue that *Consolidated Edison* held DFAX unsuitable only for stability projects, not short-circuit projects generally, quoting the D.C. Circuit's statement that "[w]e do not hold that the use of the DFAX method for short-circuit projects violates the cost causation principle per se," and the short-circuit question is now pending in the paper hearing arising from that remand.[192] Whether short circuits are properly allocated by DFAX or not is an open-ended question pending resolution. Respondents' account of the specific 2022 RTEP W3 costs confirms the same problem. CEBA says the $155.82 million Reactive Power VAR Reinforcements were properly allocated through SBDFAX because they were "designed to work in tandem" with the flow-based components of the selected proposal, driven by "reliability violations stemming from load flow analysis, not short-circuit analysis."[193] PJM TOs separately call the $155.82 million figure speculative because PJM's RTEP report does not specify whether short-circuit screening added that scope.[194] But Nelson and Eiden's own affidavit, citing the same PJM report, identifies that scope and its dollar figure specifically, and describes the VAR project as arising from PJM's separate short-circuit-and-stability screening step, not the load-flow modeling CEBA claims.[195] The same affidavit shows PJM treating a related, non-flow cost from the

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[192] PJM TO Answer at 34–35; *Consol. Edison Co. of N.Y,* 194 FERC ¶ 61,179, at P 2. On remand, the Commission must resolve whether transmission costs to address short circuit issues are appropriately allocated by DFAX.
[193] CEBA Comments at 16 (quoting PJM, 2022 RTEP Window 3 Reliability Analysis Report, at 31).
[194] PJM TOs Answer at 34.
[195] Amended Comp. Attach A (Nelson and Eiden Aff.) at 44–45 & nn.85–86.

same window differently still: $63.27 million in circuit-breaker upgrades were "directly allocated [to] the transmission zone causing the need," with no DFAX involved at all.[196]

On CEBA's own telling, the VAR reinforcements went through SBDFAX because they were bundled with a flow-based project—not because SBDFAX measured who benefits from a reactive-power or voltage need. Respondents do not explain why the same window produced two different allocation methods for two different non-flow costs, one bypassing DFAX and one run through it. CEBA itself acknowledges the underlying problem is unresolved: PJM is still "working on refining its cost allocation methodology for short-circuit needs such as breaker overloads."[197] CEBA also argues that because the VAR enhancements OPC identified are in support of projects that were identified to solve flow-based constraints, and therefore this makes it appropriate to allocate the costs of these non-flow based projects with DFAX.[198]

Finally, respondents argue that any misallocation is self-correcting. The Transmission Owners and Russo emphasize that DFAX is recalculated annually once projects enter service, so cost responsibility adjusts if forecasted load does not materialize or usage shifts.[199] CEBA adds that if PJM's load forecasts are inflated, the flaw lies in the inputs rather than the methodology: "A calculator that accurately multiplies the numbers

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196 Id. at 45 n.86.
197 CEBA Answer, Attach. Caspary Aff. at 12.
198 CEBA Answer at 16-17.
199 PJM TOs Answer at 27–28; Russo Aff. at 7–8, 16.

it is given is not broken because the user inputs the wrong numbers. The fix is to correct the inputs, not to throw out the calculator."[200]

CEBA's analogy fails on its own terms. CEBA's framing treats the load forecast and the cost allocation methodology as separable problems, ignoring the connection between the two.[201] The problem with this is that, in the event that a large load fails to materialize, or does not ramp to the full extent that was forecasted, then the zone that forecasted the large load growth will see its peak load and DFAX allocations drop as a result of this. Therefore, all else equal, the costs associated with that project or facility will be shifted to other zones. If those costs are not clearly identified as being driven by large load, and furthermore are being shifted from one state to the next, then this is more than simply an issue with 'fixing the inputs' of the load forecast.[202]

D. Retail large-load tariffs and transmission security agreements are not a substitute for correct wholesale cost allocation.

Several respondents contend that state large-load retail tariffs and utility-negotiated Transmission Security Agreements ("TSAs") already address the cost-shifting problem OPC identifies, and that this existing patchwork of state and bilateral measures makes Commission-ordered reform of Schedule 12 either unnecessary or premature. The PJM TOs devote an entire subsection of their Motion to Dismiss and Answer to the proposition that "retail tariffs and TSAs already mitigate potential risks of serving large

[200] CEBA Comments at 19.
[201] Attach. A (Nelson and Eiden Rebuttal Aff.) at 40-41.
[202] *Id*.

load customers."[203] PJM argues relatedly that states have authority to allocate retail costs.[204] But none of these arguments changes the fact that neither mechanism reaches the interstate wholesale cost shift that Schedule 12 produces, and that reliance on them would risk compounding rather than curing inequitable cost shifts.

1. TSAs are too limited to protect customers.

PJM asserts that "TSAs are an effective means to protect retail ratepayers from transmission cost shifts if the loads do not materialize."[205] The Complaint gives two reasons the TSA approach is inadequate (that PJM TOs do not address): large-load customers pay only for "customer facilities," while costs for undefined "transmission facilities" remain the utility's responsibility and are recovered through formula rates—unlike the Order No. 2003 framework, which would require the load to fund both; and the TSAs' minimum-billing protection is capped at 80 percent of expected billing determinants and pegged to the rate in effect on the TSA's effective date, "regardless of whether" the applicable rate is higher by the time a shortfall occurs, leaving large loads insulated from future rate increases that fall on other customers instead. Together, these gaps leave existing customers exposed to the bulk of any stranded transmission investment when a large load fails to materialize as forecast.[206]

The PJM TOs do not dispute this scope limitation; they instead describe TSAs candidly as "bilateral contracts addressing risk and payment obligations" that "are not,

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[203] PJM TOs Answer at 37.
[204] PJM Answer at 27.
[205] PJM TOs Answer at 40.
[206] Compl. at 50-51, Attach A (Nelson and Eiden Aff.) at 90.

nor are they intended to be, a cost allocation mechanism or rate design approach."[207] Respondents cannot simultaneously disclaim that TSAs perform any cost-allocation function and then advance them as a substitute for correcting Schedule 12's cost-allocation methodology.

The Commission itself also recognizes the limitations of TSAs. Commissioner Chang has explained that such agreements "are not specifically designed to represent the interests of other customers" and "should be treated simply as one piece of a broader package of federal and state measures to protect customers, rather than the primary or exclusive means to do so."[208]

The PJM TOs also contend that OPC's criticism of TSAs "would undercut Commission-approved bilateral agreements" and "operates as an untimely and backdoor protest, as the Commission has approved these agreements."[209] They further assert that OPC "asks the Commission to prevent acceptance of TSAs as a default."[210] These arguments may be summarily rejected. For starters, OPC's critique of TSAs is not a collateral attack. The PJM TOs themselves admit that the TSAs "do not determine cost recovery for any particular transmission infrastructure."[211] If a TSA does not determine cost recovery for any transmission facility, then the challenge cannot be a collateral

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[207] PJM TOs Answer at 41.
[208] Amended Compl. at 52 (quoting *Commonwealth Edison Co.*, Order Accepting Transmission Security Agreement, 194 FERC ¶ 61,106 (Chang, Comm'r, concurring) at PP 4, 7–8).
[209] PJM TOs Answer at 36 & n.154 (identifying PECO Energy Company's TSA filing in Docket No. ER25-3492-000 and AES Ohio's CSA filing in Docket No. ER25-192-000).
[210] Id. at 20.
[211] Id. at 41.

attack. Finally, OPC did not seek as relief a ban on or cancellation of TSAs, but instead advocated for remedies to minimize large load rate impacts that are superior to TSAs for the reasons described in the complaint.

2. State large-load tariffs cannot correct the wholesale misallocation and may exacerbate the incentive problem.

PJM and the PJM TOs both rely on state large-load tariffs as part of their answer to OPC's cost-shifting concerns. PJM argues that the existing "beneficiary pays" framework does not prevent states from allocating transmission costs more heavily to large loads, including data centers, through retail rate design.[212] The PJM TOs likewise contend that large-load retail tariffs can protect retail ratepayers when anticipated loads fail to materialize through take-or-pay requirements, financial assurances, termination penalties, and similar protections, and conclude that those tariffs, "either alone or in combination with other utility and regulatory actions," can mitigate OPC's concerns.[213]

PJM's and the PJM TOs' arguments bypass the wholesale cost-allocation problem challenged in the Complaint. As OPC explained in the Complaint, although state-level efforts "may improve outcomes for existing customers," they "fall far short and are incapable of addressing the harms of PJM's OATT."[214] State commissions can allocate FERC-approved transmission costs among customers subject to their jurisdiction, but they cannot allocate those costs to data center customers located in another state.[215]

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[212] PJM Answer at 27–28.
[213] PJM TOs Answer at 38–40
[214] Amended Compl. at 46.
[215] Id. at 46–47.

Thus, "[s]o long as PJM's hybrid methodology socializes transmission costs to zones that are not the source of expected, massive future data center load growth, no state-level remedy can ensure that rates reflect cost causation."[216]

PJM's own description of state authority confirms that limitation. PJM quotes Commission precedent stating that states determine how interstate wholesale transmission costs "assigned to a wholesale customer" are allocated among "that wholesale customer's retail customers."[217] The critical step occurs before the state ever acts: the wholesale cost must first be assigned to a wholesale customer under the Commission-jurisdictional tariff. A state can determine how costs assigned to wholesale customers within that state are recovered from retail customers; it cannot reassign costs that Schedule 12 has placed on wholesale customers in another PJM zone.

The PJM TOs make the point even more directly. In responding to OPC's argument that retail tariffs cannot prevent states from being assigned costs they did not cause, they state that "[s]tate tariffs do not need to ensure that FERC-jurisdictional rates reflect cost causation because FERC-jurisdictional rates must already do so, and if they do not, they can be challenged at the Commission."[218] That is OPC's point: state tariffs are inadequate because they cannot control how transmission costs are assigned under the Commission-jurisdictional Schedule 12 methodology.

[216] Id. at 47.
[217] PJM Answer at 27.
[218] PJM TOs Answer at 38–39.

The Commission's Large Load Show Cause Order for PJM draws the same jurisdictional line. The Commission stated that it has "exclusive authority to ensure that transmission rates are just and reasonable" and "must act to address the risk of cost shifting among transmission customers" associated with large loads.[219] States, in turn, determine how Commission-approved wholesale transmission costs are recovered through retail rates.[220] And the Commission explained that identifying "which transmission costs are caused by which transmission customers" will enable state regulators thereafter to "sub-allocate these costs to the appropriate retail customers."[221] State retail tariffs therefore operate after the Commission-jurisdictional wholesale allocation; they cannot substitute for it.

SMECO expressly acknowledges this limitation. Although SMECO argues that Maryland's RELIEF Act and the Show Cause Order proceeding reduce the need for the particular relief OPC seeks, it "agrees that state retail tariffs cannot, by themselves, reach costs allocated at the wholesale level" and describes state and federal reforms as designed to "work together, not as substitutes for one another."[222] Sierra Club similarly explains that because the cost shifting challenged by OPC occurs "at the wholesale level, across state lines," state regulators cannot resolve it through retail rates.[223]

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[219] Show Cause Order at P 68.
[220] *Id.* P 69.
[221] *Id.* P 70.
[222] SMECO Answer at 11.
[223] Sierra Club Answer at 2–3.

Nor do state large-load tariffs necessarily eliminate the stranded-cost problem. OPC argues that they can exacerbate it. The Complaint explains that if forecasted large load fails to materialize, the annual DFAX allocation can reduce the originating zone's cost responsibility and shift a greater share of the transmission costs to neighboring zones.[224]

The PJM TOs attack this "perverse incentive" argument regarding state tariffs as "unsupported and, at best, anecdotal."[225] This is not the case. When a large load tariff insulates one utility's retail customers from stranded transmission costs, it magnifies the perverse incentive for that utility to overbuild transmission.[226]

III. Since OPC has met its Section 206 burden, the Commission must determine the just and reasonable remedy.

In Part II, OPC established that the existing Schedule 12 hybrid cost-allocation methodology is unjust and unreasonable as applied to the three challenged RTEP windows. Specifically, OPC demonstrated that both the load ratio share and solution-based DFAX components of PJM's hybrid cost allocation methodology have caused more than $2 billion in transmission investment cost responsibility, misallocated to Maryland, resulting in unjust rates for Maryland customers.[227] Having done so, the Commission must consider a remedy.

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[224] Amended Compl. at 47, Attach A (Nelson/Eiden Aff.) at 55–56.
[225] PJM TOs Answer at 39.
[226] Amended Compl., Attach. A (Nelson and Eiden Aff.) at 47.
[227] Amended Compl. at 47.

Section 206 imposes a "dual burden" on the Commission: a finding that the existing rate is unjust and unreasonable is the "condition precedent" to the Commission's exercise of its section 206 authority to change that rate, and only after that finding may the Commission go on to set the replacement rate.[228] Since OPC has shown that the existing cost allocation methodology is unlawful, it "is the Commission's job—not the petitioner's—to find a just and reasonable rate."[229]

A. OPC's complaint presented three forms of relief each of which address the Section 206 violations of the current PJM tariff.

The Complaint requested three forms of relief to address the asserted Section 206 violations. First, as an immediate remedy, OPC asked the Commission to direct PJM to allocate the costs of regional baseline transmission projects built to serve incremental large load directly to the PJM zone(s) where that load is located, rather than spreading those costs by load-ratio share across the entire footprint.[230]

Second, as a longer-term remedy, OPC asked the Commission to direct PJM to develop a large-load interconnection standard modeled on Order No. 2003's generator interconnection protections, under which large loads would fund 100 percent of the upfront cost of network upgrades required "but for" the load, subject to crediting, with PJM retaining the option to charge the higher of an incremental or rolled-in embedded

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[228] *Emera Maine v. FERC*, 854 F.3d 9, 25 (D.C. Cir. 2017) (quoting *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 353 (1956)).
[229] *First Energy Services Co. v. FERC*, 758 F. 3d 346, 353 (rejecting dual burden on complainant of proving remedy just and reasonable but finding complainant did not establish existing rate's unlawfulness);
[230] *See* Amended Compl. at 54 and Part III.A ("zonal remedy")

rate, and with large loads continuing to pay for their ongoing use of the system.[231] In addition to OPC's proposed pricing remedies, the Commission should also consider the approach advanced by the IL OAG and the OCC which both urge the Commission to apply "and" pricing, *i.e.,* to direct PJM charge large loads the full incremental cost of upgrades on top of their embedded-rate share with no crediting at all.[232] The Pennsylvania Office of Consumer Advocate advocates a similar remedy though only as to Supplemental Projects.[233]

Third, OPC asked the Commission to direct PJM to reform its transmission planning process, on a prospective basis—removing large loads from RTEP load projections, developing an alternative process for assigning upgrade costs to large loads, adopting new reliability standards for large load loss, and modeling flexible or curtailable large load—on the premise that cost-allocation reform must be accompanied by planning-process reform.[234]

Finally, OPC recommends that the Commission open a paper hearing to build a record for a just and reasonable rate and cost allocation mechanism.[235]

Intervenors challenge the Complaint's remedies on a range of grounds—some contend the remedies do not go far enough to cure the cost shift, while others contend

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[231] Amended Compl. at 54-55 and Part III.B ("direct assignment")
[232] Illinois OAG Comments at 15-18; Office of Ohio Consumers' Counsel Comments at 9-10.
[233] Pennsylvania OCA, Comments at 16.
[234] Amended Compl. at Part III.D.
[235] Id. Attach. A (Nelson and Eiden Rebuttal Aff.) at 17.

they go too far, exceeding what Order No. 1000 permits or intruding on matters outside the Commission's jurisdiction. These arguments are addressed below as follows.

B. The zonal remedy is just and reasonable.

OPC proposes zonal allocation as a remedy. The Complaint asks the Commission to immediately direct PJM to allocate the costs of baseline transmission projects driven by large-load growth to the PJM zone(s) where that load is located, using PJM's legacy methodology for cost allocation by geographic area.[236] OPC's rationale for this proposal is cost causation: under the current tariff, a substantial share of upstream data center-driven costs "leaks" out of the hosting zone onto other zones' customers. By removing the leakage, costs are directed the costs to the zone causing them and leaves states free to sub-allocate them to the responsible large loads through large-load retail tariffs.[237] OPC acknowledges that the zonal allocation approach does not "fully eliminate the subsidy problem caused by large loads" but would reduce cost mismatches at the PJM footprint-wide level.[238] Respondents raise several objections to zonal allocation, discussed in the next sections.

1. Zonal allocation does not reallocate cost causation problems.

ODEC and NOVEC argue that zonal allocation merely relocates the cost-causation problem rather than curing it. ODEC calls it "dumping" costs on the zone with "zero

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[236] Amended Compl. at 55–56.
[237] *Id.* at 56.
[238] *Id*. at 56-57.

evidence" that all in-zone load benefits.[239] NOVEC says it "would simply swap one cost-causation issue for another."[240]

ODEC's complaint that OPC has not proven that every in-zone customer would benefit from zonal allocation demands more precision than Section 206 requires. Order No. 1000 requires only that costs be allocated 'in a manner that is at least roughly commensurate with' benefits, Order No. 1000,[241] and the Commission has rejected a similar demand for proof of benefits on a project by project basis as more than Order 1000's Cost Allocation Principle 2 requires.[242] NOVEC contends that zonal allocation is not an improvement, but just a different mismatch, an argument belied by the record. Under existing cost allocation practices, costs are allocated in a way that has no relationship to where the load growth driving these specific projects is occurring. By contrast, zonal allocation ties cost responsibility to the zones where that growth is actually concentrated: four zones—Dominion, AEP, ComEd, and PPL—account for 90 percent of PJM's forecasted large-load growth utilized for the three RTEP procurement windows challenged by the OPC Complaint.[243] Admittedly, zonal allocation is not as precise as direct assignment, but it represents a considerable improvement over the status quo.

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[239] ODEC Answer at 6–7.
[240] NOVEC Protest at 6–7.
[241] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 586, 639, *order on reh'g,* Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g,* Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).
[242] *Id*. at P 641.
[243] Amended Compl. at 13; Attach. A (Nelson and Eiden Aff.) at 12, 23–24.

Virginia Consumer Counsel and Ohio Consumers' Counsel both support OPC's alternative direct-assignment remedy rather than zonal allocation.[244] Virginia says zonal allocation would "sever costs from benefits, enabling free ridership."[245] Ohio says host-zone consumers "are no more responsible for those costs than are existing consumers in Maryland."[246] Virginia and Ohio's objections assume costs land in the host zone and stay there. They don't. Once assigned to a wholesale customer in-state, the state commission can sub-allocate it through a large-load retail tariff,[247] which mirrors the two-step sequence the Commission described in the Large Load Show Cause Order.[248] In the absence of zonal allocation, the second step cannot reach a cost Schedule 12 has already exported to a different state. Zonal allocation closes this gap.

DCC argues the zonal remedy isn't detailed enough to function as a section 206 replacement rate because it doesn't explain how PJM would isolate transmission needs driven "only" by incremental large-load growth when RTEP needs are typically multi-factor, and it doesn't explain how the remedy would differ meaningfully from the status quo given that nearly all PJM zones are experiencing some form of incremental large load growth.[249] DCC's claim ignores the evidence in the Complaint that four zones —

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[244] OPC agrees that direct assignment is a preferable remedy. However, the Eligible Customer serving a large load is often not yet identifiable given current jurisdictional uncertainty over who that wholesale entity is, a question the Show Cause Order may help resolve. *See* Show Cause Order at P 35 (requiring PJM and Tos to consider additional transparency requirements for network upgrades) Until the LSE can be identified to allow for direct assignment, zonal allocation is superior to the status quo.
[245] VA Consumer Counsel Answer at 2, 4–5.
[246] OCC Comments at 8.
[247] Amended Compl. at 55–56.
[248] Show Cause Order at P 70 (2026).
[249] DCC Protest at 21–22 & n.68

Dominion, AEP, ComEd, and PPL—account for on average ninety per cent of PJM's forecasted large-load additions, while Maryland's forecasted load growth stays essentially flat—proof that zones where data center growth is concentrated can be readily identified.[250]

C. Direct Assignment is just and reasonable.

As a second alternative and longer-term solution, OPC proposed direct allocation of 100 percent of baseline transmission project costs directly to the data centers causing the costs and provide as appropriate, a crediting mechanism. This approach is "informed by the customer protections embodied in the LGIA pro forma approved under Order No. 2003"—upfront funding of "but for" upgrades, appropriate crediting, and the "higher of" option.[251] The point is to borrow a solution to a problem the Commission has already solved once: Order No. 2003 "prevents existing customers from subsidizing merchant-like activity on the grid... through generator upfront funding of costs and related protections," and "[l]arge loads impose similar costs on the system as merchant generation and create the same risk of cross-subsidization."[252]

Several parties including Independent Market Monitor for PJM (Monitoring Analytics), OCC, IL OAG, NOVEC and CEBA and Virginia AG support direct

[250] Amended Compl. at 13, Attach. A (Nelson/Eiden Aff.) at 12, 23–24.
[251] *Id.* at 57-60.
[252] *Id.* at 55.

assignment, either in concept or as applied.[253] But various parties also object to direct assignment. Those objections lack merit as discussed below.

1. Direct assignment borrows the cost responsibility concept of Order 2003, not its interconnection procedures.

The PJM TOs argue that OPC's direct assignment proposal improperly grafts the Order 2003 generator interconnection framework onto large loads. The PJM TOs assert that generation and load "have different operational impacts on the transmission system," loads take transmission service while generators take interconnection service, the competitive-access concerns behind generator interconnection rules don't apply to load, and "a framework designed around generator injections... cannot simply be repurposed for load withdrawals."[254] They add that Order No. 2003 "has generated years of disputes and follow-on reforms," so extending it to large loads would import those same complications into a different context. DCC adds that "nothing in Order No. 2003 found that it was appropriate to directly assign the costs of high-voltage transmission facilities identified through the regional transmission planning process to individual generation resources."[255]

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[253] Independent Market Monitor for PJM (Monitoring Analytics ("The relief sought by Maryland OPC, that transmission costs be directly charged to data centers when those costs are identifiable, should be granted" at 3; OCC Comments at 8 and ILOAG at 11-13(endorsing direct assignment as a start but urging "and" rather than "but for" pricing); NOVEC Comments at 7 (agreeing with direct assignment but arguing for dismissal to allow show cause proceeding to advance); Virginia Consumer Counsel Comments at 2 ("Virginia Consumer Counsel would support exploring mechanisms to directly allocate baseline transmission costs to cost-causing customers where the facts support such treatment;"); CEBA Comments at 19-20 (stating it "does not oppose direct assignment where a data center is the but-for cause of a transmission upgrade identified in a local planning process."

[254] PJM TOs Answer at 52, citing Russo Aff. at 21–22.

[255] DCC Protest at 25–26.

The PJM TOs and DCC respond to a proposal that OPC isn't making. The Complaint does not seek to import the generator interconnection process, *i.e.*, the queue, the injection/withdrawal study framework, the competitive-access rules, onto large loads, or to suggest that Order 2003 applies to regional facilities. Instead, the Complaint borrows the cost-responsibility principle in Order No. 2003 uses as a model to prevent cross-subsidization upfront funding with crediting and a "higher of" backstop. This approach applies with equal force whether a customer injects power like a generator or withdraws power like a data center because both scenarios involve a discrete, identifiable increment of network expansion. Accordingly, the Commission should not discard the direct assignment option because it was originally developed for generators and not large loads.

Moreover, the Commission's own precedent suggests that generation and load are both amenable to the same framework. The PJM TOs themselves cite to Southwest Power Pool's ("SPP's") integrated transmission planning framework, which "streamline[s] its regional transmission planning and generator interconnection processes" specifically to address "historic load growth and challenges interconnecting generation and load in a timely manner."[256] SPP combined "regional transmission planning and generator interconnection processes into a single, integrated process"[257]—a framework the Commission approved and characterized as "an innovative approach to more efficiently

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[256] PJM TOs Answer at 58, citing *Southwest Power Pool, Inc.*, 194 FERC ¶ 61,192, at PP 1, 11 (2026).
[257] *Id*. at P 14.

and cost-effectively plan its transmission system."[258] If the Commission can approve a single integrated framework spanning both generator interconnection and load growth, the premise that generation and load are too operationally different to share a cost-responsibility principle is not supported by the Commission's own precedent.

2. Existing Commission precedent does not foreclose or limit the direct assignment.

DCC argues that direct assignment is barred by the PJM Large Load Show Cause Order which sets the outer limit on what large loads can be charged, and that direct assignment goes beyond it.[259] DCC explains that "in the PJM Large Load Show Cause Order, the Commission preliminarily found that, to the extent large loads are responsible for network upgrades they cause, they should be allocated costs 'based on the level of jurisdictional transmission service (in MW) requested by the Eligible Customer on behalf of the large load.'" DCC then contends that by contrast, direct assignment "contains no such limiting principle and would instead fully assign the costs of a regional transmission facility to large load customers regardless of the broad benefits the transmission facility provides to other customers or the various factors that contributed to the need for the facility."[260]

DCC mischaracterizes the Show Cause Order. The sentence that DCC quotes is not a cap on cost allocation but a formula for calculating a minimum financial guarantee an Eligible Customer acting on behalf of a large load customer has to post under a

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[258] *Id.* at P 52.
[259] DCC Protest at 25 *citing* Show Cause Order at P 83.
[260] *Id.* at 24-25.

specific agreement designed to protect other customers if the large load never fully shows up. It has nothing to do with how a facility's costs are allocated once the facility is built and used. The Commission itself clarified that this finding "is not intended to alter or call into question existing regional cost allocation methods for Network Upgrades."[261] DCC built a cost-allocation ceiling out of a sentence about a deposit requirement, and the Commission expressly said that sentence doesn't do that.

3. Direct assignment is consistent with cost-causation principles.

The PJM TOs and DCC argue that direct assignment is inconsistent with Commission practice because the RTEP facilities are regional, integrated facilities that benefit the entire PJM system, not just data centers and as such, rolled-in rate treatment is favored, absent special circumstances.[262] But as OPC has pointed out in its complaint, the assumption that everyone benefits from regional facilities breaks down when one customer type, in a discrete location demands grid capacity at a scale and speed that exceeds all other uses.[263] When that happens, cost-causation morphs into cost-shifting.

The cases that the PJM TOs cite to demonstrate the Commission's preference for rolled-in rates as a default are all distinguishable because every one of them involves ordinary system growth or ordinary interconnected-grid benefits.[264] None of these cases

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[261] Show Cause Order at P 81.
[262] PJM TOs Answer at 54–55.
[263] Amended Compl. at 10, 18
[264] *See e.g.* TOs Answer at 55, citing *e.g. Municipal Energy Agency of Nebraska and Colo. Cities v. Pub. Serv. Co. of Colorado*, 189 FERC ¶ 61,099, at P 43 (2024), reh'g den'd 190 FERC ¶61,158, PP 9-14 (2025) (rejecting a § 206 challenge to rolled-in recovery for a 560-mile, looped 345-kV transmission project that was part of an integrated network and supported by evidence of systemwide reliability, resilience, and economic benefits*); Sw. Power Pool, Inc.*, 182 FERC ¶ 61,141, PP 66, 71 (2023), *aff'd sub nom. Paragould Light & Water Comm'n v. FERC*, 144 F.4th 287 (D.C. Cir. 2025)*(*affirming inclusion of

involved a single category of customers driving an outsized, order-of-magnitude share of new transmission need as is the case with data centers. Notably, the PJM TOs ignored cases like *Tenaska Clear Creek Wind LLC v. SPP*,[265] which rejected rolled-in treatment in favor of direct assignment of network upgrade costs to an interconnection customer for which the upgrades were necessary notwithstanding incidental benefits to other system users. *Tenaska* confirms that direct assignment is not incompatible with the preference for rolled-in rates.

4. The Commission should consider implementing "and" pricing.

IL OAG and OCC, intervenors who otherwise support the Complaint, want the Commission to go further than OPC asked and reverse its prohibition on "and" pricing outright, charging large loads both the incremental and the embedded rate with no credit between them.[266] Moreover, as PA OCA explained, the Commission recently approved a pricing structure that utilized "and" pricing consisting of an embedded rate plus a separate incremental rate which was not unlawful "and" pricing so long as the expansion facility is excluded from the embedded rate base. The customer would then be "charged once for using the expansion facilities (via the incremental rate) and once for using the existing transmission network (via the embedded rate)," which Commission policy treats

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existing, locally serving transmission assets in an established zonal rate after finding that their integration into SPP's Zone 10 system would provide zone-wide integration, reliability, and power-transfer benefits); *Duke Energy Carolinas, LLC*, 168 FERC ¶ 61,190, P 18 (2019)(rejecting direct assignment of a new tap line's construction costs to the customer where the utility failed to establish that the line was non-integrated and the record showed the facility satisfied at least one integration criterion).

[265] 182 FERC ¶ 61,084, PP 32–34, 39–40 (2023)

[266] IL OAG Comments at 3, 17 ("FERC should reverse its policy prohibiting 'and' pricing..."); OCC Comments at 10–11.

as lawful disaggregated "or" pricing, not a double charge.[267] The OPC Complaint endorsed direct charging as a preferred remedy, but it "is not intended to exclude consideration of the appropriateness of other possible remedies or methods for cost recovery."[268] Therefore, OPC supports exploration of "and" pricing as an alternative.

D. The requested changes are consistent with PJM's planning process.

PJM argues that re-study would reopen its approved RTEP. It would not: the 2022 RTEP W3, 2024 RTEP W1 and 2025 RTEP W1 projects and their engineering would remain as approved. Only the allocation of their cost among zones changes, and PJM already recalculates cost shares every year under Schedule 12.[269] Re-study applies that same recalculation to three specific RTEP procurement windows.

PJM and the PJM TOs argue that costs cannot be pulled apart because RTEP plans are built on an interrelated basis. But PJM already does this within a single window when it chooses to: in the same 2022 RTEP Window 3, it sent $63.27 million in circuit-breaker costs straight to the causing zone and ran $155 million in VAR costs through DFAX.[270] Disaggregation is something PJM already does, not something it is incapable of doing.

DCC and the PJM TOs argue that a separate process for individual large-load requests would silo planning, contrary to Order No. 1920's push toward integrated planning. But PJM would still run one regional planning process producing one coordinated plan. What OPC's alternative process adds is a way to evaluate an individual

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[267] Pennsylvania OCA Comments at 14-15, citing *Public Serv. Co.*, 175 FERC ¶61,111, P 64 (2021).
[268] Amended Compl. at 64 at n.208.
[269] PJM Answer at 34-35.
[270] Amended Comp. Attach A (Nelson and Eiden Aff.) at 55, 59.

large load's request within that same framework — it does not fragment the planning itself. The PJM TOs' own cited example proves this: SPP runs a large-load-specific review step alongside its fully integrated regional planning process.[271] If SPP can do both without siloing its planning, so can PJM.

Finally, removing speculative and duplicative data center requests from PJM's load forecasts is not a change to PJM's planning methodology. PJM still forecasts, models, and selects facilities exactly as it does now. The only change is that the number feeding that process reflects real, committed demand instead of inflated or duplicate requests.

E. The proposed relief is not retroactive ratemaking, nor does it violate the filed rate doctrine.

DCC argues that the cost allocation methodology PJM applied to the 2022 RTEP Window 3, 2024 RTEP Window 1 and 2025 RTEP Window 1 projects became part of the filed rate for those projects once the Commission approved them, and that any change to that allocation now is retroactive because the allocation was already settled and final before OPC filed its complaint. DCC attempts to support this by noting that complainants who successfully challenged a PJM cost allocation methodology in the past filed before, or on the same day as, the challenged allocation took effect.[272]

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[271] PJM TOs Answer at 53 n.217.

[272] DCC Protest at 28-29 and n. 93 (citing cases and noting that complaints in *Linden VFT v. PJM Interconnection* and *PJM Interconnection* were filed prior to the effective date of PJM cost allocation filing).

Under FPA § 206(b), the Commission must establish a refund effective date upon the commencement of a § 206 proceeding and authorizes refunds of amounts paid thereafter in excess of the just and reasonable rate. 16 U.S.C. § 824e(b).
OPC seeks relief within that statutory framework. OPC does not seek to alter the projects' total approved revenue requirement for the past RTEP windows. Rather, OPC seeks to correct the *allocation* of that same project cost among the responsible customers for the period beginning on the refund effective date.[273]

In *Maryland Office of People's Counsel v. FERC*, the D.C. Circuit recently affirmed that the filed-rate doctrine does not categorically foreclose backward-looking rate modifications under § 206.[274] The court explained that § 206(b)'s refund-effective-date mechanism is a narrow statutory exception to the doctrine's usual prospective-only rule and held that characterizing requested relief as "retroactive" does not itself foreclose relief authorized by Section 206. *Id.* Specifically, the court stated the following:

Consider section 206(b), which directs the Commission to establish a 'refund effective date' upon the commencement of a section 206 proceeding. If the Commission eventually finds that the rate being charged is not just and reasonable, *it may provide refunds for 'amounts paid' during the pendency of the section 206 proceeding, 'in excess of those which would have been paid under the just and reasonable rate.'* When the

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[273] Nelson and Eiden further clarify that the purpose of its requested relief is not to re-study the need for already-approved RTEP projects but instead to replace the cost allocation method. In addition, removal of the data center load from the RTEP is for purposes of separating out the future establishment of baseline reliability projects driven by traditional, diffuse growth load from projects needed to meet growing data center demand. Attach. A (Nelson and Eiden Rebuttal Aff.) at 17.
[274] *Md. Office of People's Counsel v. FERC*, 164 F.4th 920, 929–30 (D.C. Cir. 2026),

Commission exercises this authority, it permissibly effectuates what might be thought of as "retroactive . . . rate decreases."[275] The D.C. Circuit's ruling in *Verso Corp. v. FERC*[276] demonstrates how the Commission's Section 206 authority operates in a cost-allocation case. There, the Commission had already approved both the governing cost-allocation methodology and the individual agreements at issue. After finding that the existing cost allocation methodology was unjust and unreasonable under Section 206, the Commission ordered refunds to customers that had paid too much and offsetting surcharges on customers that had paid too little, measured from the applicable refund effective dates. The court held that this remedy did not impose an impermissible retroactive rate increase because the total revenue requirement remained unchanged; the Commission had instead reallocated the overall fixed costs among the constituent payers. OPC seeks the same type of relief: correction of the allocation of an unchanged project cost, for the statutory refund period, rather than a retroactive increase in the total project charge or an alteration of charges for a period preceding the refund effective date.

That OPC's complaint is filed after PJM's cost allocation methodology was approved does not disqualify it from Section 206 relief. The operative statutory line is the refund effective date, not the date on which PJM adopted, implemented, or first applied the challenged cost-allocation methodology. But once the complaint was filed and the refund effective date established, affected charges were subject to the statutory possibility of correction if the Commission determines they exceed the just and reasonable result.

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[275] *Md. Office of People's Counsel v. FERC*, 164 F.4th at 927 (emphasis added).
[276] Verso *Corp. v. FERC*, 898 F.3d 1, 9–13 (D.C. Cir. 2018)

DCC's own authorities do not support a contrary result. In *City Utilities of Springfield, Missouri v. Southwest Power Pool, Inc.*[277] the complainant sought to reallocate costs back to the 2010 implementation of the challenged methodology, well before the refund effective date. The Commission therefore rejected that request as impermissible retroactive relief. On rehearing, the Commission expressly distinguished the *Verso* cost reallocation because *Verso* did not reach back before the § 206 refund effective date,[278] as with the relief OPC seeks here.

Occidental Chemical Corp. v. PJM Interconnection, L.L.C.,[279] another case that DCC cites is also distinguishable. *Occidental* recognized that the Commission had authority under § 206 to establish a refund effective date preceding its merits order. *Id.* P 10. The Commission nevertheless concluded, on the particular record there, that a retroactive rate-design change would be inequitable because it would prevent transmission owners from responding through a contemporaneous Section 205 filing and could cause under-recovery of an otherwise legitimate revenue requirement.[280] This case is different because there is no pending Section 205 filing.

Finally, the Commission also has broad authority under Section 309 to fashion relief necessary or appropriate to carry out the Act. Courts hold that Section 309 confers

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[277] *City Utils. of Springfield, Mo. v. Sw. Power Pool, Inc.*, 168 FERC ¶ 61,085, P 53 (2019), *order on reh'g & clarification*, 170 FERC ¶ 61,024, PP 13–19 (2020).
[278] *Id.* P 18.
[279] 110 FERC ¶ 61,378, PP 10–12 (2005).
[280] *Id.* PP 10–12.

broad remedial authority and permits the Commission, in fashioning relief, to consider equitable principles.[281]

For these reasons, the Commission should reject DCC's filed-rate-doctrine and retroactive-ratemaking defense. The Commission should instead find the challenged allocation unjust and unreasonable and award the relief permitted from the refund effective date forward.

CONCLUSION

Maryland customers are being forced to bear $1.6 billion in added transmission costs in their bills over the next 10 years (due to misallocation to Maryland of $2 billion in transmission investment) from just the three most recent rounds of PJM regional transmission projects all driven overwhelmingly by data center load growth outside Maryland's borders. Maryland customers neither materially caused nor meaningfully benefit from these transmission expansions.

The respondents who recommend dismissal of OPC's Complaint do recognize the need to address the new and unique challenges presented by data centers and large loads. Their preferred alternative is simply to brush away the issue and continue relying on existing cost allocation methodologies no longer suited to handling the demands and challenges facing the modern grid. Simply because previous cost allocation methodologies have been found to adhere to Commission principles and solve a number

[281] *Xcel Energy Services Inc. v. FERC*, 815 F.3d 947, 956–58 (D.C. Cir. 2016).

of "practical challenges" in times past, does not mean that these same methodologies are well suited to the problems of today. For the reasons discussed in this Response and Answer, OPC asks the Commission to grant the relief requested in the Complaint.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served, via first-class mail, electronic transmission, or hand-delivery, the foregoing upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated this 10th day of September 2026.

/s/ Philip Sussler
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Maryland Office of People's Counsel, Complainant, v. PJM Interconnection, LLC and Transmission Owners Designated Under Attachment A to the Consolidated Transmission Owners Agreement (CTOA), Respondents.	))))))	DOCKET NO. EL26-63-000

REBUTTAL AFFIDAVIT

OF

RON NELSON

AND

ANDY EIDEN

ON BEHALF OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

September 10, 2026

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AFFIDAVIT OF
RON NELSON AND ANDY EIDEN

I. Introduction.

Q1. Please state your name and occupation.

A1. **Nelson:** My name is Ron Nelson. I am a Founding Partner of Current Energy Group LLC ("CEG"). My business address is 4764 E Sunrise Drive, Unit #508, Tucson AZ 85718.

Eiden: My name is Andy Eiden. I am Senior Manager of Distribution System Planning and distributed energy resource ("DER") Integration at CEG, located at 4764 E Sunrise Drive, Unit #508, Tucson AZ 85718.

Q2. Are you the same Ron Nelson and Andy Eiden that previously submitted testimony in this docket?

A2. Yes.

Q3. On whose behalf are you testifying in this proceeding?

A3. We are presenting testimony on behalf of Maryland Office of People's Counsel ("OPC").

II. Purpose of testimony and high-level summary of response.

Q4. What is the purpose of your Answer testimony?

A4. The purpose of our testimony is to respond to certain arguments raised by PJM and the PJM Independent Transmission Owners ("PJM TOs") concerning the motion to dismiss and address various misconceptions or mischaracterizations made about OPC's Complaint and our supporting Affidavit. We begin with a high-level response to the main overall arguments raised by parties, and then address more specific technical critiques and challenges in subsequent sections.

Q5. What is your high-level response to the Answers submitted in this proceeding?

A5. First, many respondents echo the need to re-think existing processes and practices, whether they agree with OPC's proposed remedies or not, including some foundational practices that may have been working well for many years in the context of traditional load growth patterns. However, data centers are truly unprecedented in their scale and potential impact and therefore will require continued questioning of whether legacy methodologies continue to lead to just and reasonable outcomes.

This simple fact should not be lost when considering the relevance and need for modernizing PJM's regional transmission cost allocation methodologies and related practices. Some respondents seek to dismiss the Complaint on grounds that OPC has not sufficiently shown that the costs Maryland has been assigned from the last three Regional Transmission Expansion Plan ("RTEP") windows are in fact driven by large load growth.[1] The fact that PJM does not currently track how much of the RTEP baseline reliability needs and related project costs are attributed to large load and data center growth, even though it has existing

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[1] *See e.g.,* Exhibit No. PJMTO-001 at 17:18-18:1; Data Center Coalition Protest at 5.

methods for tracking and attributing large loads temporally and geographically through its large load adjustment process, does more to point out the inadequacy of the current RTEP process than it does to justify the respondents' preference to maintain the status quo. However, we identified significant concentration of data center load in certain load pockets in PJM's most recent load forecasts that undoubtedly created massive changes in the need for both regional transmission expansions and more localized solutions.[2]

The extent of the forecasted load growth for large loads is so massive and unprecedented that the forecasted load increases are triggering the need for both 500+ kV expansions and lower voltage facilities, despite respondents' attempts to downplay that fact. For example, PJM's 2024 RTEP objective for resolving regional transfer constraints put the matter plainly, which none of the respondents seem to acknowledge in their attempts to deflect the glaring issue, "[F]urthermore, the focus area "0 & DOM - 1" indicates scenario proposals, where the proposal could be evaluated on its own to address not only the regional need but also the Dominion zone flowgates. While there are flowgates in other TO zones that would be influenced by whatever regional solution is to be selected, the flowgates in the

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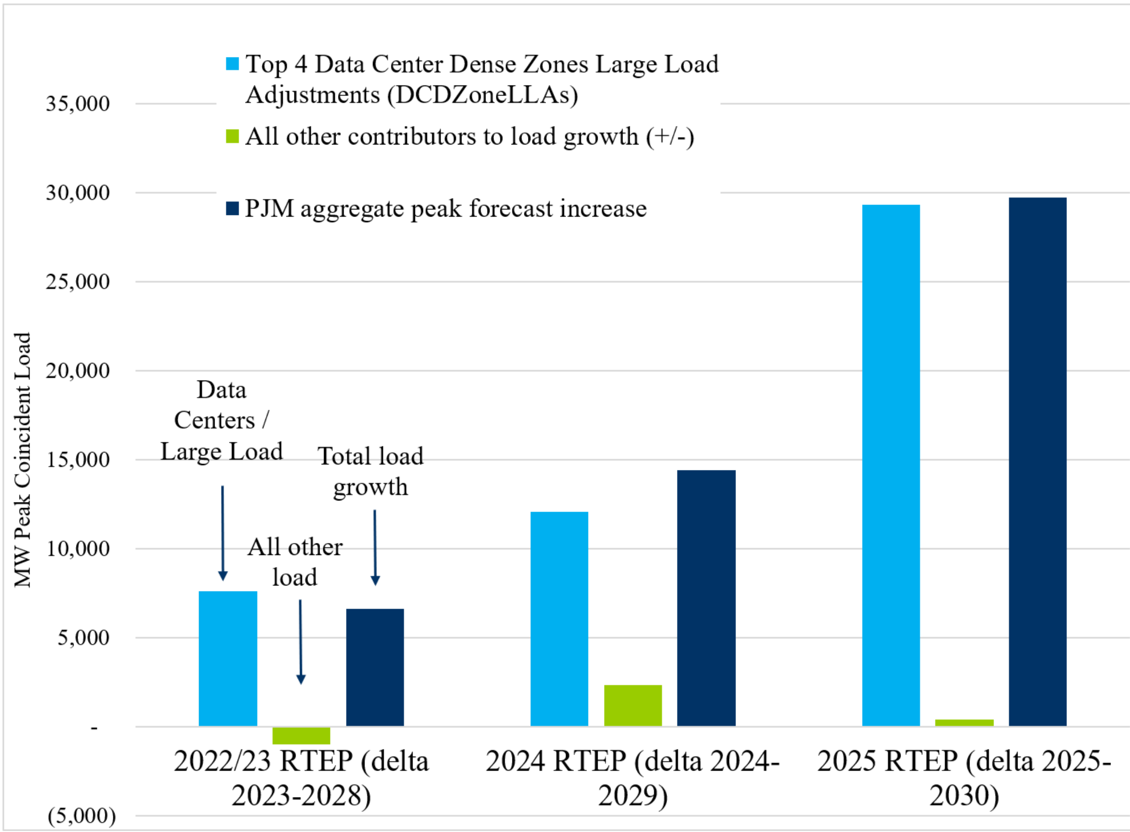
[2] *See* Nelson/Eiden Affidavit at 25, describing 80 percent of data center growth concentrated in just four PJM zones from the 2026 PJM Load Forecast. This 80 percent figure looked at the year 2032 from the 2026 load forecast, which was a year of interest within the 2025 RTEP. If we look at the critical five-year ahead time window from each successive RTEP base year (2028, 2029, and 2030 respectively for the 2022 RTEP W3, 2024 RTEP W1 and 2025 RTEP W1 procurements), Dominion alone was 88 percent of large load additions (8.7 GW out of 9.7 GW RTO wide) in 2028 under the 2023 load forecast which fed into that analysis. For the 2024 RTEP, the top two zones accounted for 93 percent of large load additions in 2029 (Dominion with 10.26 GW and AEP with 3.4 GW), and finally the 2025 RTEP had 87 percent in the top four zones (Dominion 14.6 GW, AEP 10.3 GW, PPL 4.7 GW, and ComEd 2.7 GW).

Dominion zone are so heavily intertwined with the regional solution due to the sheer magnitude of data center load driving the need for improved transfer capability."[3]

Figure 1 below shows just how much the large load adjustments ("LLAs") associated with the top four data center dense ("DCD") zones listed above contributed to overall load growth in each of the last three RTEPs compared to the PJM RTO-wide load growth. The figure shows the forecasted growth in the overall systemwide coincident peak MW, the non-LLA growth, and the LLA growth for the DCD zones in the fifth year of the respective RTEP study window. The fifth forward year of each RTEP study window is particularly important because it is used to dimension the transmission facilities planned by that annual RTEP cycle. As can be seen from the chart, forecasted LLA growth is higher than the growth than was expected on the rest of the system in the 2022 RTEP Window 3 (using the 2023 load forecast) and overall growth in the rest of the RTO footprint declined by 990 MW. From the figure you can also see the intense forecasted growth in LLAs contributing to the 2025 RTEP over previous rounds, illustrating the scale of the growing problem. When the forecast is this obviously out of balance for a single, identifiable source of concentrated load growth compared to traditional, diffuse load growth patterns, something must be done.

[3] *Reliability Analysis Report 2024 RTEP Window 1*, at 10 (Feb. 10, 2025, Rev 5).

Figure 1: Incremental forecasted coincident peak load growth -- PJM 2022/3, 2024 and 2025 RTEP Year 5 of PJM annual forecast



Moreover, the Commission recently issued an order identifying many of the same issues as those raised in the OPC Complaint as reason for finding PJM's existing tariff likely to be unjust and unreasonable.[4] Indeed, the comments by multiple intervening parties that the OPC Complaint should be dismissed because the issues raised in the Complaint are already covered or addressed in the Show Cause Order only serves to reinforce their legitimacy and relevancy with respect to

[4] *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211 (2026), Docket No. EL26-67-000 (issued June 18, 2026), *errata notice*, 196 FERC ¶ 61,122 (2026) (hereinafter "Show Cause Order").

the need to change and modernize PJM's tariff and cost allocation approach to address these challenges.

However, it is apparent that although many who recommend dismissal of OPC's Complaint do recognize the need to address the new and unique challenges presented by data centers and large loads, their preferred alternative is simply to brush away the issue and continue relying on existing cost allocation methodologies no longer suited to handling the demands and challenges facing the modern grid. The arguments attempt to pull apart the interconnected critiques advanced in the OPC Complaint and in so doing create a strawman against which each narrow practice is defended based on adherence to broad cost allocation principles and prior Commission determinations about PJM's existing cost allocation methodology. Simply because previous cost allocation methodologies have been previously found to adhere to Commission principles does not mean that these same methodologies are well suited to the problems of today.

Q6. How is the remainder of this section organized?

A6. We respond to certain claims regarding the relevancy of the recent Show Cause Order in light of critiques raised by parties, and also respond directly to certain points raised by PJM and the PJM TOs. In later sections, we respond to other intervening parties and provide detail about certain of the more technical arguments raised by PJM and the PJM TOs in their Answers.

Q7. Should not responding to a stakeholder's specific claim or argument against points raised in your initial affidavit be taken as implicit agreement?

A7. No. We have attempted to address the most relevant arguments at a high level coupled with certain detailed responses to certain technical arguments raised by respondents. Therefore, we do not reply to every objection or protest raised by respondents and silence on a particular matter does not constitute agreement.

A. The Commission's recent Show Cause Order supports the assertion that PJM's RTEP cost allocation approach is unjust and unreasonable.

Q8. Since you filed your initial affidavit, has the Commission opined on large load cost allocation within PJM?

A8. Yes. On June 18, 2026, the Commission filed its Show Cause Order in docket EL26-67. The Show Cause Order addresses numerous large load issues pertinent to this proceeding including the unique operational and planning issues, transparency and cost shifting, and cost recovery challenges.

Q9. Does the Show Cause Order address issues related to PJM RTEP baseline reliability upgrade projects?

A9. It is our understanding that the fundamental logic of the Show Cause Order requires addressing both local transmission projects identified through local utility planning or interconnection requests (i.e., "supplemental projects") and projects identified as part of the RTEP (i.e., "baseline reliability projects"). The complexity and interrelationship of the issues raised and the need to adopt a robust, comprehensive regulatory structure for transmission cost allocation and recovery requires addressing regional baseline projects as well as supplemental projects to avoid creating gaming and other issues that the Show Cause Order is meant to address. For example, only addressing supplemental projects may create perverse incentives for transmission owners to avoid certain requirements and study requirements, or create a preference for avoiding supplemental for baseline projects or vice versa. More simply, not designing complementary processes for supplemental and baseline projects is more likely to lead to unintended consequences within the two process designs. Moreover, the minimum cost recovery agreement that the Show Cause Order calls for, which would be based on the level of jurisdictional transmission service (in MW) requested and consequently the methods that PJM uses to study the new large load, is directly related to cost shifting and cost allocation[5] As is clearly implicated in these aspects of the Show Cause Order, the operational, planning, cost allocation, and cost recovery issues related to large loads must be addressed for both baseline and supplemental projects in a coordinated manner.

Q10. Can you summarize the relevant points of the Commission's Show Cause Order as it pertains to the arguments raised in your Affidavit?

A10. Yes. The Show Cause Order identifies several of the same concerns that we identified within our initial affidavit, and clearly demonstrates the need and urgency to address the operational, planning, cost allocation, and cost recovery

[5] Show Cause Order at P 81 and 83. ("That figure is in turn tied to how PJM and/or Transmission Owners will study the requested transmission service and determine any necessary Network Upgrades that must be developed to provide the requested transmission service.")

issues related to large loads we identified. While we do not provide an exhaustive list of relevant issues from the Show Cause Order, we highlight key issues relevant to our complaint. First, the Show Cause Order finds that the application, study process, and operational requirements related to large loads appear unjust and unreasonable.[6] Many of the concerns expressed by the Commission related to studies and operational requirements parallel the points we made in our affidavit and are directly related to cost allocation and the risk of cost shifting. For example, the Commission notes that:

> processes and any required studies … are not described in the Tariff with the degree of clarity and specificity necessary to ensure that the transmission provider can mitigate operational risks of providing transmission service … given their impact on the transmission system … (and) … deter speculative or duplicative requests for transmission service … and help avoid excessive and unnecessary Network Upgrades. Moreover, we are concerned that the existing Tariff does not contain other elements akin to those described below, which we preliminarily find may be necessary to ensure that the rates, terms, and conditions of jurisdictional transmission service are just and reasonable.[7]

Not appropriately identifying and addressing operational risks, addressing speculative service requests, and controlling for excessive and potentially unnecessary upgrades, both for baseline and supplemental projects, all impact the calculation and allocation of costs within the RTEP process, and need to be addressed to ensure just and reasonable rates.

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[6] Show Cause Order at P 35.
[7] Show Cause Order at P 51.

Second, the Commission recognized that speculative or duplicative service requests can impact cost allocation and cost shifting. The Commission stated that speculative or duplicative service requests on behalf of large loads can "create a substantial risk of cost shifts if the large load additions do not materialize as planned," and notes that insufficient retail interconnection and tariffs can exacerbate cost shifting issues.[8] Without modifying cost allocation approaches for both baseline and supplemental projects, namely through direct cost allocation mechanisms such as readiness requirements consisting of milestones and financial commitments, addressing speculation will remain elusive.[9]

Third, the Commission identified several large load-related costs that are not currently considered within current cost allocation approaches. For example, the Commission is concerned that transmission owners do not require large loads to install and pay for "equipment to enable PJM to monitor large loads for impacts of … fast-ramping load that may impact the transmission system … (equipment) … to remotely disconnect large loads … or ride-through requirements."[10] If the transmission owners do not require large loads to install and pay for these costs, they are either creating reliability risks for other customers (at a cost to other ratepayers) or the solutions are being socialized to other ratepayers through PJM's current, unreasonable cost allocation approaches.

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[8] Show Cause Order at P 56.
[9] Show Cause Order at P 56.
[10] Show Cause Order at P 64.

Finally, and more generally, the Commission preliminarily found PJM's Tariff unjust and unreasonable "because it lacks adequate mechanisms to mitigate the risk of cost shifting among transmission customers … ."[11] Specifically, the Commission expressed concern that PJM's current tariff provisions do not help ensure large loads and Eligible Customers requesting service on behalf of large loads "bear the risk and are ultimately responsible for costs incurred to provide transmission service, including the cost of Network Upgrades."[12] These concerns directly support OPC's Complaint that costs associated with baseline reliability upgrades required to serve large loads, and the risk of cost shifting for transmission assets built to serve the large load should they not materialize as expected, are being unduly shifted onto other ratepayers including residential customers.

The issues identified by the Show Cause Order (and the need for coordinated remedy for both baseline and supplemental projects) rebut a substantial portion of the intervenor arguments within this proceeding and demonstrate the overall reasonableness and relevancy of the Complaint.

[11] Show Cause Order at P 66.
[12] Show Cause Order at P 66.

Q11. Can you elaborate on specifically why the Commission's concerns highlighted throughout the Show Cause Order carry substantial weight in rebutting arguments raised by respondents about the OPC Complaint?

A11. Yes, while we address the more technical arguments raised by respondents in later sections, it is worth identifying the over-arching and often repeated concerns in respondents' Answers that are addressed by the Commission in the Show Cause Order. For example, Mr. Russo supports the continued reasonableness of the load-ratio share and solution-based distribution factor ("SBDFAX") cost allocation methodologies because "[B]oth allocation methods explicitly contemplate that loads in the PJM footprint will grow and change over time. The methods are designed to reflect year-to-year changes in grid usage, and thus reasonably track changes in benefits, over time, due to factors such as large load growth."[13] What Mr. Russo fails to address is exactly the Commission's concern for local transmission projects noted above, namely that for transmission assets that are built under the expectation of future large load growth, and there are costs and risks shifted to other transmission customers should that load growth does not materialize to the extent expected or at all. Instead, Mr. Russo dismisses our concerns about potential cost shifting resulting from the RTEP process as "largely predicated on the assumption" that large loads will not materialize.[14] Mr. Russo does not articulate why the concerns for cost and risk shifting are only pertinent to the types of local transmission projects that are the focus of the Show Cause

[13] Ex. No. PJMTO-001 at 15:20-16:3.
[14] Ex. No. PJMTO-001 at 16, lines 3-6.

Order. The potential for cost shifting from large load that fails to materialize is the same risk for both supplemental and regional projects.

B. The PJM Transmission Owners' arguments agree that large loads create unprecedented challenges but promote the continued status quo as the solution.

Q12. Do you have a high-level response to the PJM Transmission Owners' supporting affidavit from Witness Russo?

A12. Yes. There are a few high-level themes that emerge throughout Mr. Russo and other stakeholders' Answers. First, Mr. Russo accepts that large loads create unprecedented challenges to the transmission system, including new reliability risks,[15] and acknowledges that the Commission Show Cause Order raises several of the same issues we do in our complaint, including those related to cost allocation,[16] cost shifting,[17] and planning processes.[18] However, Mr. Russo's apparent solution to these issues is retaining the status quo with respect to how cost allocation is applied to RTEP baseline reliability projects. It is logically inconsistent to acknowledge that large loads impact several of PJM's existing processes but conclude that one of the largest cost categories within PJM should remain intact with no cost allocation changes. The simple fact that the Show Cause Order may not address regional baseline project cost allocation questions does not mean the very same dynamics are not at play, and require a similar re-consideration.

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[15] Ex. No. PJMTO-001 at 13, lines 3-4.
[16] Ex. No. PJMTO-001 at 13, lines 11-14.
[17] Ex. No. PJMTO-001 at 16, lines 10-12.
[18] Ex. No. PJMTO-001 at 23, lines 1-3.

Second, Mr. Russo attempts to create an unachievable bar for providing what he deems to be sufficient evidence that Maryland ratepayers "derive no benefits" from the transmission system.[19] This unachievable bar is created in two ways. First, Mr. Russo appears to change the commensurate benefit standard to "no benefits," which is clearly not the standard that should be applied. Large loads are the primary cause of incremental transmission upgrades, and Maryland ratepayers are not receiving benefits that are roughly commensurate with the incremental costs of transmission upgrades assigned to them to handle large load growth. Second, Mr. Russo relies on the fact that PJM and its TOs currently have insufficient study and planning processes that do not identify and quantify the costs of new transmission projects resulting from the incorporation of large loads. The fact that PJM has not taken steps to identify and quantify the costs to serve large loads is not a demonstration that these costs are non-existent. The costs being caused by large loads are currently being examined and are far reaching. Other research bodies and system operators have identified these costs, which are currently being shifted away from large loads and onto other ratepayers.[20]

Lastly, throughout Mr. Russo's testimony, he creates red herring arguments that attempt to shift the burden of proof beyond the requirements of a Section 206 Complaint. For example, PJM and the PJM TOs retain the data to answer many of

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[19] Ex. No. PJMTO-001 at 7, line 2.

[20] *See, e.g.,* https://www.aeso.ca/assets/Uploads/grid/Guide-to-AESO-Connection-Requirements-for-Transmission-Connected-Data-Centres.pdf *See also,* https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026c.pdf

the unresolved issues Mr. Russo suggests we should have presented, such as more detailed system impact studies. Additionally, Mr. Russo suggests that not having a fully implementable alternate replacement rate that is just and reasonable invalidates the Complaint. However, the Complaint demonstrates that PJM's existing Tariff is unjust and unreasonable, and, while we have made several recommendations outlining steps necessary to further build the record and identify a just and reasonable replacement rate, the ultimate solution should only be determined once this further record is established in a subsequent proceeding.

Q13. What are your overall conclusions based on your review of the Answers provided?

A13. Our conclusion is that none of the Answers provided by intervening parties opposed to OPC's proposed remedy treated it completely and should be disregarded. Intervenors variously mischaracterize OPC's intentions in filing the Complaint as Maryland merely trying to avoid paying for transmission upgrades that it benefits from and should accept. This framing is incorrect. When the rate ceases to be just and reasonable, Maryland is entitled to pursue all available remedies under the law. Respondents' commentary reflects either an unintentional misreading of OPC's arguments (by deflecting through misdirection and cherry-picking) or, at worst, an intentional mischaracterization to serve their own interest. Either way, the Commission must act on the preponderance of the evidence and evaluate whether the *prima facie* case has been made.

The fact is that arguments for dismissing the Complaint largely fall under two camps: on one hand, intervenors defend the status quo because it has been determined to be just and reasonable in the past, while ignoring the current realities posed by large loads and data centers in terms of the observed impact on the RTEP costs, and on the other hand, there are many arguments seeking to dismiss or discredit the complaint based merely on setting up and knocking down strawman arguments of OPC's positions. For instance, multiple intervenors argue that Maryland is simply attempting to avoid paying its fair share, and lean on the precedent that 500+ kV regional transmission facilities have been long held to provide "broad regional benefits" coupled with the fact that Maryland is a net importer of electricity to cast OPC's Complaint as ingenuine and therefore not worthy of further consideration. This stance is inaccurate and serves to deter the argument from reaching the merits, as evidenced by the fact that nowhere in the record did any party seeking to dismiss OPC's proposed remedy respond to OPC's recommendation to develop an upfront funding requirement to fund network upgrades that would be subject to a crediting mechanism tied to actual system usage. As stated in the initial Nelson/Eiden Affidavit, such a crediting mechanism ensures that large loads pay the ongoing use of system charges for use of the transmission system and would be credited back their initial upfront funding based on their actual use of the system.[21] Such a mechanism would send a powerful price

[21] Nelson Eiden Affidavit at Section IV.C.

signal to deter speculative load requests and also reduce the risks of stranded assets. To grant dismissal of the Complaint based on the erratic, contradictory, and strawman attacks from the intervening parties would effectively foreclose OPC's statutory rights without first building the necessary record to do so.

We reiterate our request to open a paper hearing to further build the record and, based on our review of the Answers provided in this case, we have identified further clarifying points below:

- The purpose of the paper hearing is to build the record for establishing a just and reasonable replacement rate and cost allocation mechanism for handling the issues posed by large loads. It is not to re-study the need for approval of any of the currently approved RTEP projects. In this regard, we agree with PJM when it states that any process stemming from this case should be limited to replacing the cost allocation method of those projects, not challenging the projects themselves.
- Clarify that the removal of the data center load from the RTEP is for purposes of separating out the future establishment of baseline reliability projects that are driven by diffuse, traditional load growth, coupled with generator entry and exit and other market changes, from the projects needed to meet growing data center demand. For the avoidance of doubt, the Commission should specify that in pursuing a just and reasonable rate, studying the past RTEP projects with and without large loads would be an informative study result.

- The Commission should further specify that doing so does not require PJM to completely remove the large load from its RTEP process completely, but only to develop a new process wherein projects due to large load growth are easily identified alongside projects selected for other reasons (e.g., reliability for diffuse, natural load growth, generator entry and exit, and market changes). Doing so would identify the incremental costs of meeting large load growth for purposes of informing cost allocation while still preserving the intention and capability of the regional planning process to select the suite of transmission projects that provides cost effective and efficient solutions to meet those needs.
  - PJM is currently planning to launch a new interconnection study process that combines generation and large load, along with other factors like merchant transmission and long-term firm load commitments.[22] This shows that PJM can separate these out and conduct similar screens and mutually compatible network upgrade studies. In other words, adding or subtracting large loads from the RTEP cases is technically achievable. We discuss how PJM could isolate costs associated with large loads through

[22] PJM, *Show Cause for Large Loads Framework,* Presentation at the Co-Located Load Order Workshop (August 18, 2026), at 3. https://www.pjm.com/-/media/DotCom/committees-groups/workshops/cllsco/2026/20260818/20260818-item-03---show-cause-for-large-loads-framework---presentation.pdf.

distinctive steps in a comprehensive and holistic RTEP process in Section IV.B below.

- Finally, PJM is considering cost allocation changes within its Reliability Backstop Procurement mechanism that are similar to what OPC has proposed. Specifically, costs would be allocated to the load serving entity proportionally to that entity's pro rata contribution toward the MW gap from the Base Residual Auction, with the potential to recover these costs directly from large loads.[23] This process demonstrates that cost identification, allocation, and recovery for data center related costs is in development currently for generation, and transmission allocation could use similar approaches.

[23] *See* https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-cifp-reliability-backstop-procurement-pjm-board-decision.pdf. ("The pro rata share allocation will be set by the zone/area level based on the megawatts of load additions each area is forecasted to serve, using the 2026 Load Forecast for the estimated 2028 summer load forecasts minus the 2026 summer load forecasts"); *see also* https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260630-special/item-01f---2-joint-edcs-and-data-center-coalition---rbp---executive-summary.pdf?_sp=ffdfa2bd-f12e-4bf3-b707-5756be0ccd90.1788929588649

III. Respondents' technical arguments about OPC's Complaint related to the hybrid load-ratio share and SBDFAX methodology are unconvincing and do not address the full issues raised.

Q14. First, multiple respondents argue that your recommendations amount to calling for PJM to go back to the old "violation-based DFAX" that was discarded in favor of the SBDFAX. Is this accurate?

A14. No. We never explicitly called for a return to violation-based DFAX per se as a just and reasonable replacement rate, or just and reasonable alternative to the current RTEP processes which we argued were "practices affecting rates." As such, should the Commission decide to cure those portions of the RTEP study process that do not isolate project costs not needed "but for" data center growth, then it is possible that the load-ratio share and SBDFAX could remain as just and reasonable cost allocation methodologies for those costs caused by traditional and long-standing market patterns, such as organic and diffuse load growth, generator entry and exit, and market efficiency, provided that costs caused by large loads are allocated separately as a clearly distinguishable and differentiable source of transmission expansion needs.

A. CEBA's technical arguments related to the hybrid load-ratio share and SBDFAX should be rejected.

Q15. How do respondents attempt to justify PJM's existing hybrid load-ratio share and SBDFAX cost allocation method in light of large loads and data centers.

A15. For the most part, respondents seeking to defend the existing methodologies rely on highlighting that the Commission has previously approved the method as just and reasonable under PJM's Order No. 1000 compliance filings, and that the Commission's underlying cost allocation principles have not changed even though the source of load growth is evolving.[24] Such arguments assert that the Commission's initial approval of the hybrid load-ratio share and SBDFAX methodology remains just and reasonable because it captures both broad, regional benefits associated with high voltage transmission facilities through the load-ratio share component, as well as more localized benefits reflected through the SBDFAX component.

Within this context, the Corporate Energy Buyers Association ("CEBA") argues that our arguments that the SBDFAX was inappropriately applied to allocate costs associated with stability-related system needs are misguided and "miss the forests for the trees" because the stability-related benefits associated with these project types is interchangeably captured by the load-ratio share component of the hybrid methodology.[25] In effect, CEBA is arguing it doesn't matter if the SBDFAX is inappropriate to allocating non-flow-based costs like stability-related upgrade costs, because any remaining "hard to quantify" system benefits are addressed in the bucket of the load-ratio share.

Q16. How do you respond to CEBA?

A16. Most of the benefits CEBA cites as being attributable to the load-ratio share cost allocation method are in fact now incorporated and reflected in various ways in PJM's RTEP modeling methodology or are otherwise more easily attributable now

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[24] PJM Answer at lines 24-25.
[25] CEBA Comments at lines 15-16.

with the advancement of system modeling techniques and computing power. This shift reflects the continued refinement and advancement of PJM's technical capabilities related to modeling the transmission system and the kind of modern interactions between new generation types and market products. Not to mention the "hard to quantify" benefits, which CEBA claims are adequately reflected under the load-ratio share method, are exactly the type of benefits the Commission directed PJM to address following its recent Co-Located Order. In that order, the Commission took issue with PJM's tariff for not having adequately explained how an Eligible Customer taking service on behalf of a co-located large load would pay for their fair share of various uses of the transmission system.[26] Critically, this failure and shortcoming is contemplated *precisely because of the inability of cost allocation methods based on peak load usage of the system* to reflect a just and reasonable cost allocation.

Therefore, these are not imaginary concerns OPC invented to avoid paying its fair share. By contrast, they reflect the well-documented, changing nature of the interconnected system under the new paradigm of data-center-driven load growth and co-location, and the resulting cost-allocation impacts flowing from RTEP. The Commission should recognize the interrelated nature of these issues and build the

[26] CEBA cites the *ICC v FERC* court decision as identifying operating reserves, congestion, and stability/broad reliability as the undefined or hard to quantify benefits of regional transmission facilities. The Commission found in the Co-Located Order that PJM's tariff unjust and unreasonable because co-located large loads could avoid paying for their fair share, or indeed any, transmission service if they are able to temporarily reduce their consumption from the grid during times of PJM system peak load. *See* Co-Located Order at P 5.

record further, rather than relying on "what was decided before still stands because the principles haven't changed." The principles are the same; the methods available to PJM, and the challenges it faces, are not.

Q17. Are there other arguments CEBA raises with respect to whether SBDFAX remains just and reasonable and has been appropriately applied to the RTEP projects related to large loads?

A17. Yes, CEBA argues that because the non-flow-related system enhancements OPC identified are in support of projects that were identified to solve flow-based constraints, this makes it appropriate to allocate the costs of these non-flow based projects with SBDFAX.[27] However, the fact that non-flow stability-related projects are only required to support projects selected to address flow-based constraints does not mean that this practice is just and reasonable. As stated by CEBA's expert witness, these projects are lumped together because: "[I]dentifying beneficiaries based on flow is therefore appropriate because the *beneficiaries are not the same beneficiaries you would identify if a non-flow project arose outside of RTEP.*"[28] In other words, the way PJM is allocating costs for non-flow related projects within RTEP differs from the method it uses to allocate costs for the same type of violations outside of RTEP. This underscores our claims that bundling flow and non-flow related project costs together in this way simply obscures the

[27] CEBA Answer at 16-17.
[28] CEBA Comments, Affidavit of Jay Caspary at line 12 (emphasis added).

true cost causer, and by CEBA's own admission the benefits of the project will be borne by other beneficiaries.

B. The standard is that ratepayers receive roughly commensurate benefits, not any benefit.

Q18. Witness Russo states that "if a cost allocation method is roughly commensurate with the benefits customers receive, then the allocation method can satisfy the cost causation principle."[29] How do you respond?

A18. We do not disagree with Mr. Russo's statement. However, Mr. Russo's testimony does not demonstrate that any ratepayers, much less Maryland ratepayers, receive a "roughly commensurate" benefit from the baseline transmission upgrades reflected in the last three RTEP procurement windows that are subject of the Complaint, when compared to the cost. In fact, Mr. Russo appears to avoid directly addressing the concept of a commensurate benefit by instead saying that we did not provide examples where customers "derived no benefits from the (baseline) projects."[30] However, demonstrating that customers derive no benefit is not the standard. Demonstrating a commensurate benefit is a different thing altogether. With the recent and forward-looking upgrades required to serve data center loads, the question becomes: do the required incremental expansions provide a commensurate benefit to other ratepayers? Because PJM does not identify specific projects driven by large load growth, nor make any attempt to even estimate the magnitude of costs associated with large load growth, this is

[29] Ex. No. PJMTO-001 at 9, lines 17-18.
[30] Ex. No. PJMTO-001 at 15, line 13.

likely impossible to answer with the information available to OPC. But common sense indicates that the significant gap between growth from large load adjustments compared to more traditional, diffuse sources of load growth occurring throughout the PJM region (see Figure 1above) translates to a reasonable doubt that ratepayers are not receiving roughly commensurate benefits from these upgrades.

While it is clear that ratepayers benefit from the existing transmission system, the significant and widespread incremental expansion needs are predominantly driven by large loads. Given that large load customers are a clearly identifiable and differentiable source of concentrated load growth, who also stand to gain enormous profit from an increased speed to power, it stands to reason that they are the primary beneficiaries of these upgrades.

The Alberta Electric System Operator's ("AESO's") cost allocation treatment has explicitly recognized the difference between utilizing the existing transmission system head room and future incremental additions. Specifically, the AESO created a two phased approach to cost allocation with the first phase addressing existing available capacity and the second phase being designed to evaluate who bears the cost of ancillary services and transmission upgrades related to large loads.[31] This bifurcation supports the concept that large loads and

[31] See https://www.mccarthy.ca/en/insights/blogs/canadian-energy-perspectives/alberta-faces-a-surge-in-ai-data-centre-power-demand-aeso-responds-with-phased-connection-plan

ratepayers benefit differently from existing and incremental transmission upgrades. The same is true within PJM.

Q19. Can you explain the relevancy of how the Commission is requiring modification of existing rates and tariffs that were once deemed just and reasonable, and therefore in line with cost causation principles, to account for the specific costs large loads may impose on the system?

A19. The Commission's recent findings in the Co-Located Order and Show Cause Order help to understand why simply continuing to apply general cost causation principles to the current situation with respect to data center growth is not sufficient. The Commission stated, "[I]t would be inconsistent with cost causation principles to require Eligible Customers taking transmission service on behalf of Co-Located Loads that limit their energy withdrawals to take [Network Integration Transmission Service] on a gross demand basis. Rather, Eligible Customers taking service on behalf of Co-Located Loads should be allowed to choose the transmission service that aligns with their use of the transmission system and therefore aligns the charges for service with the benefits received."[32] This shows that the Commission acknowledged the need to refine how rates and charges for transmission service associated with serving data center load in a co-located arrangement align with different levels of benefits, which to a significant degree points to the relative usage of the transmission network during system peak periods. This usage during system peak is precisely the mechanism for regional

[32] Co-Located Order at P 199.

cost allocation through RTEP underlying the load-ratio share and SBDFAX components.[33] Moreover, as the Commission articulated in the recent Show Cause Order, this concern is not limited merely to co-located arrangements, but rather pertains to all large loads whether paired with co-located generation or not.[34]

This is exactly what we explained in the initial affidavit.[35] Moreover, the Commission should recognize that just as rates and charges paid for by Eligible Customers serving large loads should be refined to more closely mirror the benefits they receive (and conversely, the costs they cause), the same realignment must be made for regional transmission cost allocation under the RTEP. This is evident because it matters little how end users are charged for different levels of service if the upstream costs allocated to that zone do not similarly reflect such considerations. This is especially important if the same requests for service were studied as firm load under the RTEP study process, and then later those same loads enter into a non-firm tariff option after the network has already been expanded.

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[33] Load-ratio share being based on the ratio of MW load during system peak. SBDFAX is also based on peak flows over specific transmission facilities for the primary DFAX calculation, which is then multiplied by the hourly net power flows in the same direction as the power flow during the time of system peak. Therefore, both methods rely exclusively or to a large degree on usage of the transmission system during system peak periods.
[34] Show Cause Order at P 87.
[35] Nelson/Eiden Affidavit at 96.

Q20. How do you respond to PJM's claim that OPC's arguments about Eligible Customers switching to co-located arrangements after being studied as firm load in the RTEP process is merely "unsupported speculation"[36] and therefore not relevant to the current proceeding?

A20. We would say that, as a matter of principle, the fact OPC did not identify any specific customer who did so, or might do so, is irrelevant. The important thing is that if it were to occur, PJM's current cost allocation process does not have mechanisms to effectively mitigate the resultant cost shift risk that other transmission customers would have to bear. However, it is not necessary for us to make the case for it when the Commission itself has already found that "parties have demonstrated that some Co-Located Loads are willing and able to control their withdrawals from the transmission system."37

C. Mr. Russo's technical support of the SBDFAX should be rejected as it ignores the emergent operational characteristics of large loads.

Q21. Please summarize the technical arguments made by Mr. Russo related to the SBDFAX allocator.

A21. Mr. Russo claims that we provide no support that stability-related reliability and VAR mitigation are inappropriately allocated through the SBDFAX.[38] Additionally, Mr. Russo claims that we do not support the reliability issues related to frequency excursions, cascading outages, transient instability, and voltage

[36] PJM Answer at 31.
[37] Co-Located Order, at P 204.
[38] Ex. No. PJMTO-001 at 10-11.

collapse.[39] Mr. Russo suggests that our claims are "general and non-specific concerns that are not supported by evidence."[40]

Q22. How do you respond to Mr. Russo's rebuttal of the technical issues related to the SBFAX?

A22. As with many of the large load issues, the more complex and unprecedented operational implications associated with large loads are currently being studied. This does not mean that the issues are non-existent or not supported. First and foremost, the Show Cause Order identifies similar concerns that we do, stating the Commission is "concerned that PJM's Tariff lacks a study process that addresses the unique operational and reliability challenges that providing transmission service to Eligible Customer on behalf of large loads presents to the transmission system."[41] The Commission went on to note that "PJM itself has recognized that enhanced large load saturation can have disproportionate impact on system reliability, including voltage and frequency fluctuations due to their size and unique characteristics … ."[42] The fact that PJM and the PJM TOs have not yet reflected the costs being caused by the unique characteristics of large loads within their studies is not evidence that these costs are not being caused by large loads and shifted onto other ratepayers.

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[39] Ex. No. PJMTO-001 at 11.
[40] Ex. No. PJMTO-001 at 11.
[41] Show Cause Order at para 53.
[42] Show Cause Order at para 53.

Furthermore, the Energy Systems Integration Group recently released a report on performance requirements on large loads; Large Load Performance Requirements: Current Practices and Recommendations ("ESIG Report").[43] The ESIG Report identifies several emerging operational challenges associated with large loads including voltage phase jump, reactive power requirements, voltage ride-through, frequency ride-through, ramp rates, and stability issues, and provides recommendations for new modeling approaches to address the operational challenges created by large loads. Many of these issues are emergent and not accounted for by the SBFAX. This is one reason the AESO plans to expand its studies and modeling to include more than steady-state power flow analysis (i.e., SBDFAX).[44] Other entities have identified several cost-causative issues that the SBFAX does not address. Not identifying, quantifying, and making changes to cost allocation process results in cost shifts from large loads to other ratepayers, including those in Maryland.

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[43] See https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026c.pdf

[44] See https://aesoengage.aeso.ca/connection-requirements-for-transmission-connected-data-centres

Q23. Mr. Russo claims that you "fail to demonstrate why a transmission owner would benefit from agreeing to serve loads that do not materialize and shifting costs to other zones nor why the SBDFAX approach in particular would exacerbate such allegedly problematic incentives as compared to other cost allocation methods."[45] How do you respond?

A23. Regarding the transmission owners benefiting from agreeing to serve loads that do not materialize, transmission owners benefit from increasing their rate base and thus their opportunity for increasing profits. The transmission owner does not have a preference for who pays for the rate base, just that rate base grows and is paid for. The annual transmission revenue requirement would stay the same, assuming there was no disallowance or other action from FERC, whether or not the large load materializes. What changes is the allocation of the costs through the annual reset of the SBDFAX and load-ratio share methodologies.

As to whether the SBDFAX would exacerbate these problematic incentives more than other cost allocation approaches, this is not at issue in this complaint as solutions should be vetted and compared to the SBDFAX in a subsequent process. However, direct allocation of costs through contribution in aid of construction could reduce the capital bias by removing incremental rate base and any associated return. Additionally, allocating to local load zones directly would likely trigger more attention from state regulators that are charged with interconnection for some large load customers, such as Dominion and other utilities without publicly filed large load tariffs such as cooperatives. In this case, where transmission costs

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[45] Ex. No. PJMTO-001 at 12, lines 6-10.

are directly allocated to local load zones, state regulators and cooperatives could address their interconnection and retail tariff to better address cost allocation issues, as the Show Cause Order suggests.

Q24. Mr. Russo claims that the perverse incentives we explain related to retail tariffs, such as inflating forecasts, are speculative and unsupportive, and that large load retail tariffs can address speculation and perverse incentives. How do you respond?

A24. We disagree with Mr. Russo for several reasons. First, not all utilities with large loads have large load tariffs, so protections do not exist for all ratepayers. Second, the Show Cause Order explicitly notes that the transmission service agreements ("TSAs") lack transparency are likely insufficient to protect ratepayers. FERC has highlighted that current TSAs are insufficient for protecting ratepayers.[46] If this transparency is lacking at the wholesale level, it is almost certainly lacking at the state level as well. Lastly, even if a retail tariff increases the likelihood that a large load will materialize, that does not eliminate or address risk to a reasonable degree. Large loads are the size of large cities. Not all data centers need to be speculative to create enormous, stranded asset costs, only one large data center needs to do so. The speculation in the market is well documented, and while a retail tariff may address this to some degree, it does not eliminate risk to

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[46] Show Cause Order at P 65, stating "we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks *pro forma* provisions in a transmission service agreement … We are concerned that, without such *pro forma* provisions in a transmission service agreement between PJM and the transmission customer, PJM may be unable to enforce ongoing operational requirements for transmission customer taking transmission service on behalf of large loads."

ratepayers or act as a substitution to cost allocation reform. It is important to note the basics of ratemaking. Rates are based on a class revenue requirement. The revenue requirement is based on the costs allocated to the class. If cost allocation does not reflect a reasonable portion of the costs, rates will not recover a reasonable amount of costs regardless of the tariff terms and conditions.

D. Maryland's position relative to the market and generation deactivations occurring in the state are irrelevant to the issue of whether PJM's RTEP cost allocation methodologies remain just and reasonable in the face of unprecedented large load growth.

Q25. Many respondents criticize OPC's Complaint by pointing out that Maryland is a net importer of electricity, and further that Maryland has further benefitted from socializing transmission upgrade costs driven by generator deactivations, most notable Brandon Shores.[47] How do you respond?

A25. As discussed elsewhere, we are not disputing that Maryland ratepayers have historically benefited from being connected to the regional transmission system. The topic at issue in this proceeding is whether Maryland ratepayers have commensurately benefited from incremental transmission upgrades related to large loads, which they have not. This fact is documented throughout our testimony.

The comparison of unprecedented large loads, with over 100 GW of connections within the PJM queue, to the Brandon Shores power plant proposed deactivation is irrelevant and misses the mark. Brandon Shores is a generator that was separately identified as a project driver for an RTEP solution with a unique project number and specific facts. As demonstrated by the Show Cause Order, no

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[47] *See* PJM Answer at lines 25-26; Ex. No. PJMTO-001 at lines 18-20; Data Center Coalition Protest at line 8; CEBA Comments at lines 14-15.

such facts exist for large loads. In fact, many of Mr. Russo's arguments rely on the fact that PJM has not identified, studied, or quantified the impacts of large loads, and suggests the lack of action and process development on PJM's part is a shortcoming of our complaint.

These two issues are not comparable. Importantly, for several decades the transmission network has implemented frameworks that allocate the costs of generator connections and deactivation; generator deactivation is not a recent nor unique phenomenon. On the other hand, loads have never over this period reached the size that current data centers are connecting at. There is no precedent for cost allocation and recovery for connection requests that commonly exceed 1 GW. Comparing the two issues ignores the fact that the Brandon Shores deactivation has a developed process for addressing the issue, transparent data collection and studies, decades of precedent, and the fact that the Commission and PJM could foresee the potential deactivation coming for decades (i.e., generators have a depreciable life). While on the other hand, large loads of recent sizes have never connected to the system and create numerous unprecedented challenges that must be addressed to maintain affordability for other customers; the Commission and PJM cannot turn their heads and ignore unprecedented cost shifting.

Q26. Respondents characterize the Brandon Shores closure as a deliberate policy choice and attempt to point out the asymmetry in only discussing cost allocation issues associated with data center load. How do you respond?

A26. Intervenors repeatedly frame the pending Brandon Shores retirement as a "Maryland" policy choice[48] and thereby seek to cast the broader criticisms OPC raises against the treatment of unprecedented data center load growth as somehow one sided. There are three problems with this argument that, when taken together, show why the Commission should ignore this narrative when deciding on the merits of this Complaint.

1) Maryland did not "force the closure" of the Brandon Shores power plant to meet its climate change state policy goals. Brandon Shores is a privately-owned merchant generating facility pursuing its own economic interests.[49, 50] However, Talen later announced its decision to retire the unit instead of pursuing the oil conversion due to a combination of "increased plant conversion costs and decreased future revenue projections based on recent PJM market changes.[51]

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[48] *See e.g.,* CEBA Comments at 14. ("Maryland's decision to retire the Brandon Shores power plant highlights the integrated nature of PJM's transmission grid and the problems with trying to allocate costs only to zone-specific
causers of a transmission need.")
[49] Brandon Shores is wholly owned by Talen Energy Corporation, an independent power producer.
[50] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Steam Electric Reconsideration Rule), 85 Fed. Reg. 64,650 (Oct. 13, 2020) (codified as amended at 40 C.F.R. pt. 423).
[51] Talen Energy Corp., Amendment No. 1 to Registration Statement (Form S-1), at 44 (July 1, 2024). ("In the first quarter 2023, due to increased project costs and declining PJM capacity revenues, management concluded that the lower return on investment to convert Brandon Shores' fuel source from coal to fuel oil no longer met Talen's investment criteria.") At the time that Talen was evaluating the future expected

2) PJM is the governing entity responsible for maintaining reliability and resource adequacy throughout its member states, not individual states. The respondents' attempts to cast this issue as a simple equivalency (i.e., private merchant generator exits the market in your state, so you lose standing to protest unjust and unreasonable outcomes due to other causes) is misleading.

3) The physics of power flows over specific transmission facilities constructed to alleviate a constraint based on the SBDFAX methodology are not the same as import and export balance, as some respondents argue.[52] CEBA argues that Maryland should seek to address its cost allocation for regional transmission lines by "changing the physics of the grid by developing in-state generation" as opposed to seeking remedy for PJM's existing cost allocation mechanism, and further that if it does construct more in-state generation "its DFAX for regional projects will decrease because supply and demand can be

returns from converting the plant from coal to oil, the capacity auction results for BGE's Zone dropped from $126.5/MW-day in the 2022/23 auction year to $69.95/MW-day in the 2023/24 delivery year, which when calculated against the expected MW plant capacity (assuming 1,289 MW of net dependable capacity with a 5 percent forced outage rate), would have amounted to approximately $25.3 million per year in reduced future expected revenues from the capacity market alone, thus significantly impacting Talen's decision making. Talen may have evaluated lower plant runtimes for the planned oil conversion as well, which could have impacted future revenue projections. However, this again was due to Federal Clean Air Act limitations on SO2 emissions, and not subject to Maryland's state policy. *See* 87 Fed. Reg. 66,086, 66,088 (Nov. 2, 2022), describing plant runtime limits per federal guidelines.

[52] *See* CEBA Comments at 17. ("If Maryland elects to construct generating facilities within its borders, its DFAX for regional projects will decrease because supply and demand can be matched in-state. Until that happens, power flow modeling will reflect the reality that Maryland ratepayers benefit heavily from their use of PJM's baseline reliability projects to import power to serve their load.")

matched in-state."[53] This is not only contradictory to the PJM statement that the Commission has found that both "importing and exporting benefit from the system"[54] but it also contains a logical contradiction. If every state perfectly balanced its inflows and outflows throughout PJM, then all zones would net to zero and no costs for the transmission system would be recovered under this theory. The problem with this thinking is, of course, that the physics of the grid that underly the SBDFAX calculation are decoupled from net energy inflows and outflows. This is further support that Maryland's net position to the market is irrelevant to determining whether a given tariff governing cost allocation from the RTEP is just and reasonable.

E. Respondents incorrectly state that PJM's RTEP modeling cannot and should not be re-run to identify specific causing zones or customers.

Q27. PJM states that the Commission should deny the Complaint's demand that PJM re-study the RTEP baseline reliability projects across the three windows because "[T]he Complaint makes no claim that PJM improperly conducted the analyses for these windows."[55] Do you agree?

A27. No. As described above, the Complaint identified the RTEP modeling process, and the related input processes regarding how the RTEP incorporates the load forecast including large load forecasts, as "practices affecting rates". As such, the OPC Complaint did claim these were improperly applied, and because they are

[53] CEBA Comments at 17.
[54] PJM Answer at 24, citing *PJM Interconnection*, 142 FERC ¶ 61,214.
[55] PJM Motion to Dismiss and Answer at 7.

purported to be "practices affecting rates" they are properly situated under the OPC's Section 206 filing rights and the Commission's review authority.

Q28. Does PJM have other concerns with your proposed remedy?

A28. Yes. PJM further states that "[OPC] does not establish any basis for requiring PJM to retroactively identify, on a facility-by-facility basis, the extent to which individual transmission facilities were driven by particular data center load or other discrete planning assumptions."[56]

Q29. What is your response?

A29. This critique mischaracterizes the OPC position in two ways. First, the proposed remedy does not call for identifying cost causation on a "facility by facility" basis for each particular data center load, as this would amount to "exacting precision" that may prove infeasible given the high number of discrete data center loads and facilities required to mitigate violations. By contrast we only recommended studying the RTEP baseline reliability needs with and without data center load *as a whole*. The Complaint specifies this as the appropriate approach because only by so doing can PJM's method distinguish the rough proportion of costs that would not be needed "but for" the new data center load. We discuss this recommendation further in Section IV below to further clarify how our proposed remedy aligns

[56] PJM Answer at 7.

with broader regional transmission planning goals such as using a holistic approach to planning to identify efficient solutions.

Second, our Affidavit clearly states that the Commission should further build the record before determining the replacement rate, and, by extension, the needed modifications to the RTEP process. Therefore, if there are legitimate reasons why the modeling cannot be carried out as we suggest, the Commission can elect to approve alternative approaches as it sees fit to accomplish the goals of mitigating cost shifts and inefficient system expansion resulting from large load data center growth in regional transmission expansion.

Q30. Do any other parties raise similar issues surrounding OPC's proposed remedy for modifying PJM's broader planning practices as it pertains to incorporation of data center load forecasts in the RTEP?

A30. Yes. CEBA agrees with OPC around the need for reforms in how PJM is handling data center forecasts, stating, "[F]or instance, the complaint is entirely correct that PJM's load forecasting methodology badly needs attention from this Commission. Although PJM has taken steps over the last year to try to improve its forecasting, there is still work to be done."[57] However, CEBA concludes that "the forecast quality does not undermine the validity of the SBDFAX methodology," and that "disrupting sound cost allocation principles to fix planning inputs is inefficient,

[57] CEBA Comments at 18 (additional citations omitted).

unlikely to succeed, and ultimately counterproductive to shared reliability and affordability goals."[58]

Q31. How do you respond to the claim that "fixing the inputs" of the load forecast would solve the issues raised in the Complaint?

A31. CEBA's reasoning here misses the broader connection that we drew between the inflated data center load forecast and the ongoing operation of the hybrid load ratio share and SBDFAX cost allocation methodologies. Because other parties also misconstrue this concept, we will elaborate on the initial point we raised.

When large load forecasts are incorporated into the broader system-wide load forecast and included in the RTEP baseline reliability needs assessment, certain factors are set in motion with respect to ensuring that costs will be incurred to resolve any reliability violations that arise due to the load forecast, and any other changes like generator additions and deactivations modeled in a given scenario. This is why we argued that the RTEP baseline reliability modeling, and its treatment of the large load forecast from utilities throughout PJM, are all "practices affecting rates" and should therefore be considered under a Section 206 Complaint filing.[59]

When these projects are identified and selected, they cause costs to be incurred. Initial approval of the cost allocation is based on peak load ratios and SBDFAX model runs to determine relative facility usage based on the expected

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[58] CEBA Comments at 19.
[59] OPC Complaint at 66-67. *See also* Nelson/Eiden Affidavit at 14.

load in each zone at the time of project approval. Respondents variously argue from here that because PJM updates its allocation factors annually, this “corrects” for any issues of cost shifting and can accurately reflect the beneficiary pays principle over time as the grid continues to change.

The problem with this is that, in the event that a large load fails to materialize, or does not ramp to the full extent that was forecasted, then the zone that forecasted the large load growth will see its peak load and SBDFAX allocations *drop* as a result of this. Therefore, all else equal, the costs associated with that project or facility will be shifted to other zones. If those costs are not clearly identified as being driven by large load, and furthermore are being shifted from one state to the next due to the mechanics of the hybrid load-ratio share and SBDFAX, then this is more than simply an issue with “fixing the inputs” of the load forecast. Important as it is to reduce speculation and improve the quality and certainty of the load forecast, the Commission also must address the interaction of the large load forecasts included in RTEP insofar as they impact the costs borne by transmission customers to serve their expected load, and the cost allocation mechanism PJM uses to allocate those costs to customers.

Q32. What are your conclusions?

A32. PJM’s current practice fails to distinguish forecasted large load demand growth in the RTEP planning cycle and therefore leads to unjust and unreasonable rates because the costs associated with large data center expansion are not identifiable and are therefore causing excessive cost and risk shifts to existing customers, including residential customers.

IV. OPC's proposed remedy for isolating costs caused by data centers would not interfere with regional transmission planning goals outlined in Order No. 1920.

A. Respondents mischaracterize OPC's proposed remedy, meant simply to isolate costs attributable to large load growth in the RTEP process, as leading to a fractured transmission planning process that is counter to the goals of Order No. 1920 and efficient grid expansion.

Q33. Please summarize the arguments concerning how OPC's proposed remedy would allegedly lead to fragmented regional transmission planning.

A33. PJM argues that OPC's proposed remedy to remove data center load from the forecasts feeding into the RTEP reliability modeling and planning workstreams would "result in developing an unrealistic model that is disconnected from the forecasted load" and "result in an RTEP process…that would no longer be able to plan for some of the region's largest projected loads, defeating the entire purpose of the regional planning."[60] PJM also claims the recommendation, were it to be adopted, is tantamount to PJM being "subjected to a piecemeal planning regime."[61] CEBA also repeatedly invokes Order No. 1920 to dismiss the Complaint as likely to contribute to "diminishing regional transmission" and "fracturing" the process into a "tragedy of the transmission commons" and would require "disrupting regional transmission planning writ large".[62]

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[60] PJM Answer at 33.
[61] PJM Answer at 33.
[62] CEBA Comments at 19.

By contrast, PJM highlights how the current planning process "selects the more efficient or cost-effective solutions to address the identified system needs holistically as part of its RTEP. The RTEP process evaluates transmission needs on a system-wide basis by considering load, generation and market factors together."[63]

Q34. What is your response to these claims?

A34. The arguments that OPC's proposed remedy will lead to inefficient transmission planning outcomes are based on a misunderstanding of OPC's position, which we take this opportunity to clarify. What seems to be central to the misunderstanding is the OPC recommendation that the Commission direct PJM to "remove data center and other large loads completely from the load projections feeding into RTEP reliability modeling and planning workstreams".[64]

Contrary to how PJM and CEBA portray OPC's position, the OPC Complaint includes important additional context, stating, "[B]ased on these findings, Nelson and Eiden recommend that the Commission direct PJM to remove data center and other large loads completely from the load projections feeding into RTEP reliability modeling and planning workstreams *and develop an alternative planning process that provides the information necessary to assign network upgrade costs to large load customers seeking interconnection*."[65]

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[63] PJM Answer at 7.
[64] PJM Answer at 33, citing OPC Complaint at 67.
[65] Complaint at 64 (emphasis added).

Nothing in this statement says that PJM should remove data center load and ignore it, as PJM and CEBA implicitly characterize it. On the contrary, the Complaint specifies that the Commission should direct PJM to "develop an alternative planning process" that would not only include large loads but would also allow for identification of the costs they are causing.

B. PJM already conducts staged RTEP analysis that demonstrates OPC's proposed remedy is reasonable, and separately, would serve to accomplish a variety of important policy goals.

Q35. Are there reasonable alternative methods to identify efficient transmission solutions to solve regional planning problems that do not require PJM to include large load as an undifferentiated input to the load forecast factoring into its baseline reliability assessment as part of the RTEP process?

A35. Yes, and we explained this at a high level that , "[T]his could be done, for example, by requiring system modeling to occur with and without the addition of the large load(s) and quantifying the resultant differences in system reliability needs and associated costs."[66] The additional context shows that OPC's recommendation is to remove the large load and data center load forecasts from their current place within PJM's planning processes, namely the portion that identifies the baseline reliability needs and associated projects. These data center loads can still be added to the overall load and generation mix to be appropriately studied under PJM's "holistic" approach to regional planning, just with the added benefit of isolating large load forecast inputs and the projects they trigger to inform later cost allocation decisions. Identifying the costs driven by large loads in

[66] Nelson and Eiden Affidavit at 98 (emphasis added).

this manner cannot currently be done the way PJM plans the RTEP expansions, which is the point we emphasized.

Q36. Can you provide an example of a current PJM practice within its RTEP modeling process that is similar to the process improvements you are recommending?

A36. Yes, and to reiterate, we are not recommending to remove large loads entirely from PJM's RTEP process, contrary to respondents' claims.[67] As described above, we are advocating for the separate tracking of large load growth as distinct inputs to the transmission expansion planning process, coupled with identifying which projects are needed to resolve the new constraints they introduce. PJM's own process to screen baseline RTEP projects already includes a similar process called "Market Efficiency Analysis", which occurs after the baseline reliability projects have been identified and selected, and is meant to; "[I]dentify economic benefits associated with modification of reliability-based transmission projects already included in the RTEP that when modified would relieve one or more economic constraints. Such projects, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefits as well."[68] PJM's process for assessing the benefits and costs of market efficiency projects is very similar to the method OPC proposed in the initial Complaint, and

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[67] *See e.g.,* Russo Affidavit at 27, lines 1 through 16.
[68] PJM Market Efficiency Process Scope and Input Assumptions, June 2026, at 1, available at https://www.pjm.com/-/media/DotCom/planning/rtep-dev/market-efficiency/informational-market-efficiency-analysis-assumptions-july-2026.pdf

that we clarified above: "[T]o calculate the benefits of these potential economic-based enhancements, *PJM will perform and compare market simulations with and without the proposed accelerated reliability-based enhancements or the newly proposed economic-based enhancements* for selected future years within the planning horizon of the RTEP."[69] Therefore, PJM could modify its existing processes for incorporating large load growth into the RTEP for purposes of informing baseline reliability needs in a similar fashion as it already does with respect to market efficiency analysis. PJM could develop a new "efficiency" screening step that is meant to ensure projects selected to meet large load growth are adequately considered with other drivers, such as deactivations and market efficiency considerations. This process is not unreasonable and would meet Order No. 1920 objectives of a holistic long-term approach to regional transmission planning while also mitigating many of the issues raised in the Complaint regarding large load and data center cost shifting concerns that are supported by many of the Commission's recent findings.

Q37. Are there any other responses you would like to address?

A37. Yes. The Data Center Coalition claims that by highlighting the shortcomings resulting from how the current hybrid load-ratio share and SBDFAX cost allocation method is applied, when considered in connection with the limitations of state retail tariffs in protecting native load customers from undue cost shifting,

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[69] PJM Manual 14b, Revision 59 (Apr. 22, 2026), at 54 (emphasis added).

we are recommending the Commission act against the interests of cooperative federalism and "use its authority over transmission planning and cost allocation to target perceived shortcomings in existing retail tariffs."[70] On the contrary, we plainly stated in our initial affidavit that our concern was precisely the opposite, namely, that if the Commission does not act to correct shortcomings associated with the lack of transparency into which costs for regional network upgrades are driven by data center load growth, that states would be frustrated in their attempt to achieve their goals in protecting their retail customers. This is a very different proposition than what the Data Center Coalition paints it as. Viewing our recommendation in the correct light illustrates that it is in line with Commission precedent and actually supports and furthers cooperative federalism, as opposed to somehow being against it as the DCC claims.

V. Conclusion.

Q38. Does this conclude your testimony?

A38. Yes.

[70] Data Center Coalition Protest at line 20.