



COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH KEYSTONE BUILDING
400 NORTH STREET
HARRISBURG, PENNSYLVANIA 17120

August 17, 2026

Via Electronic Filing

The Honorable Debbie-Anne A. Reese,
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

**Re: Pennsylvania Public Utility Commission Complaint v. PJM
Interconnection, LLC, Docket No. EL26-98-000.**

Dear Secretary Reese:

Please find for e-filing the Complaint of the Pennsylvania Public Utility Commission (PA PUC) against PJM Interconnection, LLC, at Docket Nos. EL26-____-000 and Request for Expedited Action.

Copies of this document have been served upon Christopher O'Hara, Senior Vice President, General Counsel, Thomas DeVita, Assistant General Counsel, Mark J. Stanis, Associate General Counsel, and Steven R. Pincus, Esquire, Associate General Counsel of PJM Interconnection, LLC.

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

Respectfully submitted,

/s/ Kriss E. Brown

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

Pennsylvania Public Utility Commission)
Complainant)

Docket No. EL26-__-000

v.)

PJM Interconnection, LLC.,)
Respondent)

**COMPLAINT OF THE PENNSYLVANIA PUBLIC UTILITY
COMMISSION**

Pursuant to Sections 206 and 306 of the Federal Power Act (FPA),¹ and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure,² the Pennsylvania Public Utility Commission (PA PUC) hereby files this complaint against PJM Interconnection, LLC (PJM) in that Schedule 6, Section 1.5.7 of PJM's Operating Agreement is unjust, unreasonable, and unduly discriminatory or preferential in the manner it selects market efficiency projects, thus harming Pennsylvania consumers. For the reasons stated herein and in the attached Direct Testimony of Zachary Ming, Partner, Energy and Environmental Economics, Inc. (E3),³ the PA PUC requests that the Commission

¹ 16 U.S.C. §§ 824e and 825e.

² 18 C.F.R. § 385.206.

³ The Written Testimony of Zachary Ming is Attachment A to this Complaint.

direct PJM to include the impact of all (benefitting and non-benefitting) zones when calculating consumer benefits for the purposes of market efficiency projects⁴ by either:

(1) deleting from PJM's Schedule 6, Section 1.5.7 of the Operating Agreement, the following red-lined language from the definitions of "Change in Load Energy Payment" and "Change in Load Capacity Payment."

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone without the Economic-based Enhancement or Expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the Economic-based Enhancement or Expansion)]
.... ~~The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.~~

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]. ... ~~The Change in the~~

⁴ Direct Testimony of Zachary Ming at 39.

~~Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.~~

(2) Alternatively, PA PUC requests the Commission order PJM to revise its Operating Agreement to add the increase in Load Energy Payment and Load Capacity Payment to the denominator of the Benefit-Cost Ratio, in the definition of Total Enhancement Cost. The resultant definition would be:

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the Economic-based Enhancement or Expansion **plus the Change in Load Energy Payment for the Zones that show an increase in the Load Energy Payment and Change in Load Capacity for the Zones that show a decrease in the Load Capacity Payment.**

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion **plus the Change in Load Energy Payment for the Zones that show an increase in the Load Energy Payment and Change in Load Capacity for the Zones that show a decrease in the Load Capacity Payment.**

While the PA PUC does not request fast-track procedures under Rule 206(b)(11), PA PUC requests expedited action as PJM continues to select market efficiency projects in an unjust, unreasonable, and discriminatory fashion. PA PUC requests implementation of this relief on a going-forward basis with an effective date as of the date of this filing. That is, PA PUC is not seeking retrospective implementation prior to the filing date.

COMPLAINT

I. THE PARTIES

PA PUC

The Pennsylvania Public Utility Commission is an independent agency charged and authorized by the Pennsylvania General Assembly to balance the needs of consumers and utilities; ensure safe and reliable utility service at reasonable rates; protect the public interest; educate consumers to make independent and informed utility choices; further economic development; and foster new technologies and competitive markets in an environmentally sound manner.

PJM

PJM is the regional transmission organization (“RTO”) for all or part of 13 states⁵ and the District of Columbia. PJM operates organized wholesale electricity markets and manages the high-voltage electricity grid to ensure reliability for more than 65 million people. As a private RTO, PJM plans regional transmission lines within its territory using administrative planning methodologies.

⁵ The 13 States include: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. See link: <https://www.pjm.com/en/about-pjm/who-we-are/territory-served>.

II. INTRODUCTION

Under the FPA, States are the default siting authorities.⁶ While a recent Third Circuit panel decision⁷ has somewhat confused jurisdictional boundaries, under *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369 (2024), federal agencies are not granted deference to act through a non-governmental organization. There is no clear Congressional authorization to expand FERC jurisdiction through the RTO it regulates to somehow acquire siting authority outside a National Interest Electric Transmission Corridor (NIETC). PJM is a private entity. PJM exercises no independent federal power. It operates pursuant to tariffs approved by the Commission under the FPA and its own Operating Agreement.⁸ While addressing the federal goal of regional transmission and cost allocation in Order No. 1000, the Commission explicitly cautioned that the transmission planning outlined in the Order “in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states,” i.e., siting. FERC Order No. 1000, 76 Fed. Reg. 49842-01.

PA PUC is charged by statute with fostering the provision of safe and reliable service at reasonable rates to the retail customers of utilities subject to

⁶ See 16 U.S.C. §§ 824(a), 824p.

⁷ *Transource v. DeFrank, et al.*, No. 24-1045 (3d Cir.) (judgment entered on Sept. 5, 2025).

⁸ The PJM Operating Agreement describes the process for posting needs, opening a project proposal window, reviewing proposed projects, and determining which transmission projects will be included in the recommended plan. PJM Interconnection, L.L.C., 154 FERC ¶ 61,096, at P 2 n.2 (citing PJM Operating Agreement, Schedule 6, §§ 1.5.8 (b)-(d)).

PA PUC jurisdiction. 66 Pa.C.S. §§ 501, 1301-1304, 1308, 1309, 1501, 2802(9).

PA PUC regulates the siting of high-voltage electric transmission lines under the Pennsylvania Code Title 52, Sections 57.71–57.77 (relating to PA PUC review of siting and construction of electric transmission lines), 52 Pa. Code §§ 57.71–57.77.

Pennsylvania requires entities seeking to site and construct high voltage transmission lines within its borders to establish, by a preponderance of the evidence, that there is a public “need” for the project. *See* 66 Pa.C.S. §§ 1101, 1102, 1501; *see also* 52 Pa. Code § 57.76. To determine whether there is a “need,” the PA PUC considers evidence regarding “present and future necessity of the proposed [high voltage] line in furnishing service to the public.” 52 Pa. Code § 57.75(e)(1). Over forty states require state permits and siting approval for high voltage electric transmission facilities within their state lines. *See* James J. Hoecker and Douglas W. Smith, *Regulatory Federalism and Development of Electric Transmission: A Brewing Storm?*, 35 Energy L.J. 71, 82 (2014). These rules ensure that transmission projects are reviewed for public health, safety, environmental impact, and reasonable alternatives before approval. The PA PUC is the only siting authority within its borders for high-voltage transmission projects that are needed and sufficiently competitive to procure the most cost-effective solutions.

For transmission projects planned under PJM Interconnection's Market Efficiency framework⁹, the reduction of congestion¹⁰ can allow generation to be built in the most cost-effective locations and then distributed throughout the region. Oftentimes, the most cost-effective location is Pennsylvania due to broad support for an all-of-the-above energy generation strategy and the maintenance of adequate dispatchable generation capacity in the PJM region.

Likewise, the Pennsylvania General Assembly has encouraged competitive regional markets for electric generation and interstate power pools.¹¹ The PA PUC welcomes the economic development of generation located in Pennsylvania and the ability to provide electric generation supply services to its constituents and the region for the benefit of all. However, Pennsylvania, a net-exporter State¹², cannot

⁹ PJM's Schedule 6, Section 1.5.7 of the Operating Agreement. *See also* PJM Manual 14B: PJM Region Transmission Planning Process, Section 2.1.3 Market Efficiency Planning, 2.2 The RTEP Process Drivers, 2.6 RTEP Market Efficiency Planning, and Attachment E: Market Efficiency Analysis Economic Benefit/Cost Ratio Threshold Test.

¹⁰ Congestion occurs when the least-cost available energy cannot be delivered to load in a transmission constrained area and higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to provide that energy, after virtual bids have been settled in both the day-ahead and balancing markets. Congestion can be defined to be total load payments in excess of generation revenues, excluding marginal losses, from both the day-ahead and balancing markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. *See* Attachment A - Testimony of Zachary Ming at pp. 8-9. *See also* PJM billing examples in the Independent Market Monitor's *2019 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

¹¹ 66 Pa.C.S. §§ 2802(19), (20), 2805(a).

¹² An interactive hourly State Net Import/Export Map may be found on PJM's website at <https://www.pjm.com/markets-and-operations/State-Import-Export-Map.aspx>.

be expected to bear all burdens associated with generation while also bearing unjust or unreasonable costs for transmission projects to export power to neighboring states simply because PJM seeks parity in wholesale pricing throughout its entire system and because some States are actively retiring generation without sufficient replacement within their borders.^{13,14} The current market efficiency selection process, in the name of parity, unreasonably, unjustly and in a discriminatory manner ignores price increases in the locational marginal price (“LMP”) zones that are upstream of transmission constraints that cause congestion in order to lower prices in zones downstream of the constraint.

The current market efficiency selection construct serves to dampen the market signals to build generation close to the load it serves; thus, causing transmission projects to be selected that are not necessary to maintain reliability, which in turn results in unjust, unreasonable and unduly discriminatory transmission rates. Transmission and generation in a congested zone are

¹³ *Sierra Club v. PJM Interconnection, L.L.C., Complaint of Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and Union of Concerned Scientists*, Docket No. EL24-148-000 (Sept. 27, 2024). See *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,088 (2025).

¹⁴ *Maryland’s Near-Term Challenge: Preserving Resource Adequacy During a Period of Transition*, PJM, January 15, 2025, at <https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250115-presentation-maryland-general-assembly-economic-matters-committee-resource-adequacy.pdf>. *Virginia Energy Report: Policy Roadmap for the Commonwealth*, The Center for Energy Science and Policy Schar School of Policy and Government at George Mason University, October 2025, at <https://cesp.gmu.edu/wp-content/uploads/2025/10/Virginia-Energy-Report-2025-Policy-Roadmap-for-the-Commonwealth-Final.pdf>.

competing to alleviate market inefficiencies. A project selection methodology that unreasonably overstates the benefits of a transmission solution may suppress the price signal to build generation in the congested zone, even when the construction of that generation may represent the most efficient or least-cost way to reduce the congestion and serve load.

When transmission projects are selected through a method that ignores the increased costs in areas upstream of the congestion, the principles of a well-functioning and overall cost-effective wholesale market for generation are violated.¹⁵ The PA PUC files this Complaint under Rule 206 of the Commission's Rules and Regulations because the Market Efficiency project selection process does not consider overall costs in both the net-beneficiary zone and other zones.¹⁶

The current rules governing market efficiency project selection suppress market signals to build new or upgrade existing generation in areas downstream from the point of constraint, which could lower congestion costs and more reasonably solve a congestion cost issue without the siting and construction of new transmission facilities that will be paid for by customers throughout the region. The current rules regarding market efficiency project selection are an impediment to the objectives of the Secretary of Energy's advance notice of proposed

¹⁵ See Attachment A, Direct Testimony of Zachary Ming dated July 30, 2026, at pp. 3-4.

¹⁶ 18 C.F.R. § 385.206.

rulemaking (ANOPR) issued for comment in October 2025 pursuant to section 402 of the Department of Energy Organization Act.^{17, 18} This ANOPR directed the Commission to consider taking additional actions to address the addition of large and co-located loads to the transmission system. The ANOPR observed that “siting a large load near or at the same point of interconnection as a new generating facility could reduce the network upgrades needed to interconnect only the load or only the generating facility.”¹⁹ ANOPR at P 20.

III. BACKGROUND

A. The Federal Power Act

The FPA, 16 U.S.C. §§ 791a, *et seq.*, preserves a dual system of clearly defined federalism. Through its ratemaking authority, FERC regulates transmission sales and wholesale power sales in interstate commerce, and the states retain authority over siting and permitting of specific utility assets within their

¹⁷ "The Secretary ... [is] authorized to propose rules, regulations, and statements of policy of general applicability with respect to any function within the jurisdiction of the Commission under section 402 of this Act." 42 U.S.C. § 7173(a). "NEPA does not apply to rulemaking actions proposed by the Secretary pursuant to section 403(a) of the DOE Act ... because such proposals are not final agency action." DOE NEPA Implementing Procedures, § 2.1(c)(8) (2025).

¹⁸ See *Secretary of Energy's Direction that the Federal Energy Regulatory Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act*.

¹⁹ See *PJM Interconnection, L.L.C. et al.*, EL26-67, 195 FERC ¶ 61,211 (Order issued June 18, 2026) citing *Interconnection of Large Loads to the Interstate Transmission System, Advance Notice of Proposed Rulemaking*, Docket No. RM26-4-000 (Oct. 23, 2025) (ANOPR); see also *Letter from Chris Wright, Sec'y, U.S. Dep't of Energy*, Docket No. RM26-4-000 (Oct. 23, 2025).

borders, including transmission lines, generation plants and distribution networks.²⁰

B. PJM's 2007 Economic Planning Proposals.

PJM has had a process for planning economic transmission enhancements since at least 2002.²¹ In July 2005, ahead of the rulemaking that led to Order 890,²² PJM instituted a stakeholder process to improve market efficiency transmission planning, resulting in a September 2006 filing to implement that improved process. In June 2007,²³ the Commission accepted in part the PJM market efficiency project enhancements. However, the Commission also determined that PJM's proposed selection method was not sufficiently detailed regarding the methodology for selecting market efficiency projects. In response, in October 2007, PJM submitted

²⁰ *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, PP 227, 253 n.231, 287, 76 Fed. Reg. 49,842 (2011) ("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, P 342, 77 Fed. Reg. 32,184 (2012) ("Order No. 1000-A"), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044, 77 Fed. Reg. 64,890 (2012) ("Order No. 1000-B"), *aff'd sub nom.*, *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *see, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154-155 (2016) (describing the jurisdictional divide set forth in the FPA); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 266-267 (2016) (explaining that "the [FPA] also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction").

²¹ FERC Orders in 2002 (101 FERC ¶ 61,345 at P 24) that approved PJM as an RTO specifically directed PJM to include an economic transmission planning process.

²² *Preventing Undue Discrimination and Preference in Transmission Service*, 118 FERC ¶ 61,119 (Issued February 16, 2007) (Order No. 890).

²³ PJM Interconnection LLC, ER06-1474, 119 FERC ¶ 61,265 (2007) (Order On Compliance issued June 11, 2007).

a compliance filing (2007 PJM Proposal) describing both the project selection criteria and cost allocation methodologies.²⁴

The 2007 PJM Proposal treated facility project selection differently by voltage, splitting between 1) Regional Facilities and Necessary Lower Voltage Facilities, and 2) other Lower Voltage Facilities. The 2007 PJM Proposal further distinguished between two types of benefits, Energy Market Benefits and Reliability Pricing Benefits, and provided weights for the components of Energy Market Benefits and Reliability Pricing Benefits.

The “Total Annual Enhancement Benefit” is the Energy Market Benefit plus the Reliability Pricing Benefit. Expanded, this calculation is $[.70] * [\text{Change in Total Energy Production Cost}] + [.30] * [\text{Change in Load Energy Payment}] + [.70] * [\text{Change in Total System Capacity Cost}] + [.30] * [\text{Change in Load Capacity Payment}]$. For Lower Voltage Facilities alone, the terms “Change in Load Energy Payment” and “Change in Load Capacity Payment” only included those zones that showed a decrease in payments. For Regional Facilities, which are allocated

²⁴ PJM Interconnection LLC, ER06-1474 (Compliance Filing filed October 9, 2007).

according to both Load Ratio Share as well as allocation based on electric flow, those terms also included those zones that showed increases in payments.²⁵

The Commission stated that the approach was reasonable because “it would match the project selection process to the existing cost allocation method. That is, it would evaluate the load payment benefits of those loads that will be assigned the costs of the new facilities.”²⁶

C. PJM 2014 Filing

In 2014, PJM revised the Project Selection cost-benefit methodology. First, PJM changed the weights used for production costs and load payments. But second and more importantly, PJM abandoned the notion that regionally allocated projects should account for cost increases in zones that pay for the project. PJM sought revisions to its economic planning process as set forth in section 1.5.7 of Schedule 6 of the Amended and Restated Operating Agreement of PJM stating, “[e]liminating from the calculation consideration of zones with an increase in net load or capacity payments should increase the number of projects that could

²⁵ See PJM’s Second Compliance Filing, PJM Interconnection, L.L.C., Docket No. ER06-1474-004 at 4, 7 and 8 (Oct. 9, 2007). The formulaic approach was further amended by way of compliance. See PJM’s Third Compliance Filing, PJM Interconnection, L.L.C., Docket No. ER06-1474-006 (Jun. 16, 2008). The reduction in production costs is a standard measure of the economic benefits of an expansion or enhancement. The change in production costs measures the economic benefit of the project to the PJM market, while the load payments measure the extent to which the project will reduce prices to load. Together the evaluation of production cost benefits and direct benefits to load customers were intended as a reasonable formulaic approach to the analysis of the overall benefits of an economic-based enhancement or expansion. See October 9 Compliance Filing at 7 and 8.

²⁶ PJM Interconnection, L.L.C., 123 FERC ¶ 61,051, P 67 (2008).

qualify as a market efficiency project.”²⁷ Without addressing the original justification given by the Commission when approving the 2007 PJM Proposal, PJM instead simply stated that it “believes this modification to the market efficiency benefit calculation will more appropriately align the benefits with the costs of the facilities by placing the cost of such upgrades on the zones where costs are being reduced.”²⁸

The Commission accepted the filing via a Delegated Letter Order,²⁹ which stated in pertinent part as follows.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against PJM.³⁰

²⁷ Docket No. ER14-1394, (Filed February 28, 2014) at page 10. PJM proposed to: (i) revise how the market efficiency benefits are calculated for Regional Facilities, Necessary Lower Voltage and Lower Voltage Facilities; (ii) include generation with an executed Facility Study Agreement (“FSA”) in its assumptions; (iii) modify the definition of Production Cost to appropriately account for resources from neighboring RTOs which can be dispatched and are active in PJM’s market efficiency models (“dispatchable resources”). In approximately 2018, PJM’s market efficiency base case for its RTEP process no longer by default includes generation resources that are in the Facility Study phase or have an executed FSA or suspended Interconnection Service Agreement (ISA).

²⁸ PJM Interconnection, L.L.C., Intra-PJM Tariffs, [OA Schedule 6 Sec 1.5, OA Schedule 6 Sec 1.5 Procedure for Development of the Regional Transmission Expansion Plan, 5.0.0](#). Docket No. ER14-1394, at 8 (PJM Revisions to Economic Planning Process Filed February 28, 2014).

²⁹ Delegated Letter Order, Docket No. ER14-1394 (Issued April 23, 2014).

³⁰ *Id.* at page 2.

Through the Docket No. ER14-1394 proceeding, the benefit was changed to allow the complete exclusion of all zones that are forecasted to see higher Load Energy Payments (LEP) for Lower Voltage Projects.

IV. LEGAL STANDARD

Under the FPA, regulated entities are required to file with FERC “schedules showing all rates and charges ... and the classifications, practices, and regulations affecting such rates and charges.”³¹ Once filed, “no change shall be made ... in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days’ notice to the Commission and to the public.”³² “As the statutory terms make clear, the filed rate is not limited to ‘rates’ *per se*, but also extends to matters directly affecting rates.”³³ In addition, under the Commission’s “rule of reason,” utilities must file “those practices that affect rates and service significantly, that are realistically susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous.”³⁴

³¹ 16 U.S.C. § 824d(c).

³² *Id.* § 824d(d).

³³ *Oklahoma Gas and Electric Co. v. Federal Energy Regulatory Commission*, 11 F.4th 821, 829 (D.C. Cir. 2021).

³⁴ *Keyspan-Ravenswood, LLC v. FERC*, 474 F.3d 804, 811 (D.C. Cir. 2007); *see also Chehaulis Power Generating, L.P.*, 145 FERC ¶ 61,052, at P 11 (2013) (“Section 205 requires that rates, terms, and conditions for jurisdictional services must be filed with the Commission; the statute does not make such a filing optional, or otherwise grant discretion to utilities to decide whether or when they must file their rates, terms, and conditions.”).

The FPA establishes a two-part process to challenge charges demanded by public utilities. *First*, a complainant must establish by a preponderance of the evidence that one of PJM’s “rule[s], regulation[s], practice[s], or contract[s] is unjust, unreasonable, unduly discriminatory, or preferential.”³⁵ A rule may be deemed unjust or unreasonable when it “ha[s] not resulted in, and likely would not incentivize, the development of additional supply capable of resolving the problem going forward.”³⁶ *Second*, once this burden is satisfied, the Commission must then promulgate a just and reasonable alternative rule, regulation, practice, or contract.³⁷ The FPA states that “no public utility shall ... make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage [or] maintain any unreasonable difference ... between localities.”³⁸

There is no automatic, rebuttable presumption that PJM’s Operating Agreement is just and reasonable. The Commission has previously determined certain aspects of the Operating Agreement to be unjust and unreasonable, such as in July 2016 wherein the Commission identified inconsistencies in how PJM handled transmission needs driven solely by individual transmission owner Form No. 715 criteria.³⁹ In that case, the Commission issued a Rule to Show Cause

³⁵ 16 U.S.C. § 824e(a).

³⁶ *Citadel FNGE Ltd. v. FERC*, 77 F.4th 842, 855 (D.C. Cir. 2023).

³⁷ 16 U.S.C. § 824e(a).

³⁸ 16 U.S.C. § 824d(b).

³⁹ *See PJM Interconnection, L.L.C.*, 156 FERC ¶ 61,030, at PP 20-21, 24 (2016) (July 2016 Order), order on reh’g, 157 FERC ¶ 61,193 (December 2016).

under FPA Section 206 requiring PJM to show cause why its Operating Agreement was just and reasonable or make revisions to clarify process and to define “Immediate-need Reliability Projects.”⁴⁰

V. ARGUMENT

A. PJM’s Market Efficiency Project Selection Is Unjust, Unreasonable, And Unduly Discriminatory And Preferential

PJM’s methodology for calculating the benefits of market efficiency transmission projects explicitly only considers the impacts to benefiting consumers in zones that will experience lower energy costs as a result of the project, while ignoring the impacts to consumers in zones that will experience higher energy costs. This unduly discriminatory and preferential treatment is unjust and unreasonable and is inconsistent with the mandates of the FPA.

By discriminating against a subset of loads, PJM has effectively excluded a subset of consumers from their “consumer” benefits metric. Instead of planning transmission in the public interest of all consumers, PJM is effectively acting in the interests of a subset of consumers who would benefit from a particular project, even at the expense of other consumers who may be made worse off. PJM’s methodology can yield the unreasonable outcome of market efficiency projects that actually **increase costs for consumers in aggregate in PJM**. In fact, PJM’s

⁴⁰ See *PJM Interconnection, LLC*, 162 FERC ¶ 61,033, ER16-2401 and EL16-96 (Order issued January 18, 2018).

methodology may actually increase load energy costs across the entire region before even accounting for the cost of the transmission project itself. In other words, PJM consumers can be forced to pay for transmission projects that actually increase aggregate energy costs.

Ignoring cost increases to certain zones is unduly discriminatory and preferential and contrary to caselaw precedent of *El Paso Electric Co. v. FERC*, 76 F.4th 352 (5th Cir. 2023) No. 18 60575 (5th Cir. 2023), wherein the U.S. Court of Appeals for the Fifth Circuit reversed the Commission’s cost allocation orders for grid improvements in the WestConnect region, and reaffirmed the cost causation principle as a foundational tenet of ratemaking.⁴¹ Cost allocation in transmission planning pursuant to FERC Order No. 1000 must be tied to actual cost causation, not broad mandates that impose costs on utilities without clear justification.⁴²

B. PJM's Market Efficiency Benefits Methodology Over-Procures Transmission To The Detriment Of The Region

We agree with FERC’s statement in Order No. 890: “When planning to serve native load customers, a prudent vertically integrated transmission provider will plan not only to maintain reliability, but also consider whether transmission upgrades or other investments can reduce the overall costs of serving native load.

⁴¹ *El Paso Electric Co.* 76 F.4th at 363.

⁴² *Id.* at 366.

Such upgrades can, for example, reduce congestion (redispatch) costs or integrate efficient new resources (including demand resources) and new or growing loads.”⁴³

The purpose of a market efficiency project is to satisfy the Commission-endorsed goal to reduce costs for customers and allow generation to be built at the lowest cost location for the benefit of customers. The appropriate measurement criteria to accomplish that goal is all-in cost for *all* customers. It is inappropriate to count changes in load payments only in those zones that experience a benefit. Changes to PJM’s project selection criteria and cost allocation methods have exacerbated the need for reform.

PJM prices reflect a single clearing price system-wide, after line losses, and customers located near generation receive little benefit from this proximity. During those limited hours when congestion exists, congestion may cause lower prices for customers proximate to generation, while eliminating the congestion will lead to greater price parity.

The market response to price increases is to build more generation in the most profitable location. This is accomplished through the balance of locating projects where it is least expensive to build combined with the price of energy that can be earned at that location. When transmission is built to resolve price

⁴³ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, ¶542 (47 FR 18569, March 15, 2007) RM05-17-000 and RM05-25-000.

differences between locations, greater consideration is given to locating generation where it is least costly to build as the price differential is reduced or eliminated. Downstream of the congestion, the result is lower energy prices. Upstream of the congestion, however, energy prices often increase.

The price increases from reduced congestion should not be ignored in project selection. Ignoring those costs creates a system that over-procures transmission when building more generation in a congested zone would have been the least cost option. A better result is to maintain the price signal in the few hours of the year when congestion is projected to occur or has occurred. It should be noted that modern technology, such as battery storage, allows temporal energy market arbitrage, without the need to build extremely large capital projects to address occasional system constraints.

C. Reducing Congestion Is Not The Sole Goal Of An Efficient Market

Costs to deliver power represent a significant market friction. Substantially reducing that market friction creates a boon to customers, allowing lower cost power to be built and delivered to consumers. However, reducing congestion has no value beyond the savings provided to the region as a whole and is not a value in itself. When locational constraints arise in any locational market there are essentially three options: 1) increase transfer capacity to address the constraint, 2)

increase production within the constrained pocket, or 3) bear the costs of the constraint.

As described earlier, reducing congestion can result in generation development decisions solely concerned with locating generation in the least cost location. However, international experience with congestion reduction should inform the Commission that congestion reduction is not an end in itself. The transmission system of the Alberta Electric System Operator was a prime example of the approach whereby congestion costs were reduced without accounting for full regional costs and benefits. The Alberta Electric System Operator recently decided to move away from the then current zero-congestion transmission planning standard to an optimally planned transmission planning standard. Alberta policy requires effectively zero congestion, instead of evaluating whether reduced congestion produces a net benefit for the region holistically.

No ISO or utility currently plans transmission to eliminate or reduce congestion for its own sake. Rather, ISOs and utilities only seek to eliminate or reduce congestion when the cost of the transmission project is less than the cost of congestion. When the cost of congestion is less than the cost of the transmission project required to relieve it, bearing the cost of congestion is economic.

According to the Fraser Institute, “it is economically beneficial that transmission policy address the location of electricity generating facilities in order to ensure that

the delivered cost of electricity is as low as possible.”⁴⁴ That is, the project selection cost-benefit analysis should evaluate the cost effects on all zones because transmission and generation are substitutes. The option of locating production within the load pocket must be evaluated if that option is less expensive than raising prices system wide plus the cost of the transmission line itself.

Some congestion may be acceptable under certain conditions. It may be less expensive to simply bear occasional high prices than to build a transmission line to eliminate price differences. Project selection for market efficiency solutions should seek to minimize the combined system-wide costs of electricity production and transmission. The Commission itself has recognized that generation and transmission compete, and that the goal of good system planning is to select and build the overall most cost-effective portfolio of solutions, both transmission and non-transmission.⁴⁵

⁴⁴ <https://www.fraserinstitute.org/sites/default/files/AlbertaElectricityTransmission.pdf>.

⁴⁵ *See, Bld'g for the Future Through Elec. Reg 'I Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ~ 61,068, at PP 1625-48, *order on reh 'g & clarification*, Order No. 1920-A, 189 FERC ~ 61,126 (2024), *order on reh 'g & clarification*, Order No. 1920-B, 191 FERC ~ 61,026 (2025). *See also, Ensuring the Timely and Orderly Interconnection of Large Loads, Advance Notice of Proposed Rulemaking*, Docket No. RM26-4-000 (Oct. 27, 2025).

D. Other Regions Do Not Calculate Benefits In This Way Or Provide Other Mechanisms To Ensure All Zones Benefit

i. MISO

The PJM Project Selection Methodology was originally modeled upon Midcontinent Independent System Operator's (MISO) weighted gain-no loss metric, with modifications.⁴⁶ A detailed review of the MISO tariff shows that it includes zones where costs increase in the determination of total benefits for the purpose of project selection. Attachment FF provides that for the purpose of Market Efficiency Projects, "[t]he Transmission Provider shall apply the benefits metrics outlined in Attachment FF-7 and sum the results of each of the benefit metrics together to determine the economic benefits of a Market Efficiency Project to the Transmission Provider region."⁴⁷ Attachment FF-7 of the MISO *Open Access Transmission, Energy and Operating Reserve Markets Tariff* provides that Adjusted Production Cost Savings and Avoided Reliability Project Savings are used to determine the benefits used to qualify a market efficiency project for selection. There is no limitation contained in the MISO tariff which limits the sum of benefits to only include zones that benefit. Instead, "[u]nder its 'Weighted Gain-No Loss' proposal, the MISO seeks to ensure that proposed economic projects will have a **regional benefit**."⁴⁸ Further, benefits are "determined in aggregate for all generation and load nodes."⁴⁹

After project selection, MISO, along with other RTOs, allocates costs among zones so that “the cost of any such projects are borne only by those entities that benefit from the proposed upgrade,” but that allocation occurs only after project selection. Critically, MISO is considering the total costs and benefits of the project regionwide at the project selection phase, not only when determining cost allocation.

ii. SPP

Southwest Power Pool’s (SPP) “Balanced Portfolio” project selection methodology does not exclude zones that receive a negative benefit in determining project selection. As approved by FERC, SPP portfolios are treated as meeting the cost-benefit test “when the sum of the net present value of the benefits of the upgrades equals or exceeds the net present value of the costs of the upgrades.”⁵⁰ SPP even includes a further check. In the words of the Commission when approving SPP’s methods: “no zone will be worse off as a result of the adoption of a balanced portfolio.”⁵¹ When a zone’s production costs do increase as a result of

⁴⁶ Compliance filing, PJM Interconnection, LLC, Docket No. ER06-1474-004 (Filed October 9, 2007).

⁴⁷ Attachment FF Section B.1.a.

⁴⁸ Midwest Independent Transmission System Operator, Inc., ER06-18-004, ER06-18-005, 118 FERC ¶ 61,209 (Issued March 15, 2007) (emphasis added).

⁴⁹ Midwest Independent Transmission System Operator, Inc., ER06-18-004, ER06-18-005, 118 FERC ¶ 61,209 (Issued March 15, 2007).

⁵⁰ Initial Order on Compliance, 125 FERC ¶ 61,054.

⁵¹ Initial Order on Compliance, 125 FERC ¶ 61,054, P 21.

trapped generation becoming “untrapped” SPP requires rebalancing of costs to ensure the increased zones don’t pay.⁵² Unlike PJM, SPP still treats those zonal cost increases as a reduction in net benefits at the project selection phase.⁵³ There is no tariff provision that excludes zonal cost increases from its production cost benefits calculation.

iii. NYISO

New York ISO (NYISO) uses a societal benefit metric to evaluate whether a candidate RETP is in the public interest. The primary measure is a region-wide production cost test that asks whether the project reduces total dispatch costs across New York State as a whole. This captures the net change in total dispatch costs across all zones, including zones whose costs increase because of the project. NYISO does not identify capacity cost savings or other non-energy benefits as separate benefit categories in its economic project evaluation framework. Only after a project passes the region-wide production cost test does NYISO proceed to identify which specific zones experience price decreases for the purposes of cost allocation and the opt-in vote.

⁵² Initial Order on Compliance, 125 FERC ¶ 61,054, P 31.

⁵³ Attachment O (Transmission Planning Process) of its Open Access Transmission Tariff (OATT), Section IV.4(d)(iii) ("The adjusted production cost benefit for each Zone shall equal the difference between the adjusted production cost with the potential Balanced Portfolio modeled and without the potential Balanced Portfolio modeled.").

All zones are included in the region-wide production cost test, including those that experience cost increases. Zones harmed by a project are not excluded from the benefit calculation; their negative impacts reduce the measured net benefit and can cause a project to fail the test. Harmed zones are not held financially whole under cost allocation, but their welfare is reflected in the selection decision.

iv. ISO-NE

ISO New England's (ISO-NE) Tariff contains no provision limiting the calculation of benefits for project selection purposes to those zones that benefit. ISO-NE's website describes the purpose of its project selection methodology succinctly. "System Efficiency Transmission Upgrades" (SETUs) are "designed to reduce *overall system production costs*."⁵⁴ ISO-NE uses a societal benefit metric. The primary benefit measure is production cost savings across the full New England system and the surrounding NPCC region. In addition to production cost savings, ISO-NE includes two supplemental benefit categories: avoided transmission losses (the reduction in energy wasted in transmission as a result of the upgrade) and avoided future transmission investment (the cost of other planned transmission upgrades that are no longer needed because of the candidate project). Capacity cost savings are not a separate benefit category in ISO-NE's economic project evaluation framework.

⁵⁴ <https://www.iso-ne.com/system-planning/transmission-planning/setu>.

Production cost savings are calculated on a system-wide basis across all New England load zones. No zone is excluded from the analysis on the basis that it experiences a cost increase as a result of the candidate project. Cost allocation for approved SETUs follows a load-ratio basis across the full region, consistent with ISO-NE's principle that all consumers benefit from improvements to the interconnected regional network.

v. CAISO

Although the California ISO (CAISO) does not conduct market efficiency windows in the same way as many of the other RTOs, it does have its Transmission Economic Enhancement Methodology. CAISO has made its position on this issue clear: “[f]undamentally, net benefits should be the summation of the benefits for all market participants who pay for the project less their costs. Since most projects will enhance the welfare of some market participants while diminishing the welfare of others, a project’s acceptability should be judged based on the impact in aggregate.”⁵⁵ Although CAISO uses a consumer benefit metric rather than a societal one, it does not discriminate among ratepayers based on whether they benefit from a project. The ratepayer benefit calculation reflects the net change in consumer costs across all pricing zones in the

⁵⁵ https://www.caiso.com/documents/transmissioneconomicassessmentmethodology-nov2_2017.pdf.

CAISO footprint, including zones that experience higher costs. No zone is excluded from the calculation because it experiences a cost increase.⁵⁶

E. PJM’s Project Selection Methodology Has Increased All-In Costs For Regionwide Customers

An enhancement proposed by Transource Energy LLC (what PJM referred to as “Project 9A”), yielded the following results as described by the PJM Independent Market Monitor (“IMM”):

Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the benefit/cost ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis. The initial study had a benefit to cost ratio of 2.48, with a capital cost of \$340.6 million. The sum of the positive (energy cost reductions) effects was \$1,188.07 million. The sum of negative effects (energy cost increases) was \$851.67 million. The net actual benefit of the project in the study was therefore \$336.40 million, not the \$1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.⁵⁷

Another example is the 644+908 Multi-Driver project in the COMED-NIPSCO-AEP Area, which was proposed as part of the 2022 Regional Transmission Expansion Plan. The IMM once again showed how the results

⁵⁶ Direct Testimony of Zachary Ming Appendix: Jurisdictional Review of Select Transmission Project Economic Evaluation Frameworks in North America.

⁵⁷ https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, p. 2.

would have drastically changed if PJM accounted for the impact to all consumers rather than just the beneficiaries of the transmission:

The benefit/cost analysis used in the multi driver review is the same flawed benefit/cost analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions to some loads) effects of \$169.8 million. The sum of the present value of negative effects (energy cost increases to other loads), which was ignored in the PJM calculation of benefits, was \$149.1 million. The total benefit of the proposed multi driver project is therefore only \$20.7 million, not the \$169.8 asserted by PJM, even ignoring the use of changes in congestion rather than changes in production costs. Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/cost ratio is 0.24, not 1.99. All \$149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd Zone. Based on the requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi driver project should have been rejected.⁵⁸

The IMM, has repeatedly raised this issue in State of the Market and FERC filings. For example, the IMM has stated that:

[t]he current rules governing the benefit/cost analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules explicitly ignore the increased zonal load costs that a project may create ... These flaws have contributed to PJM approving market efficiency

⁵⁸ Monitoring Analytics, "2024 State of the Market Report for PJM", [2024 State of the Market Report for PJM](#), page 715.

projects with forecasted, and realized, costs that are higher than the forecasted benefits.⁵⁹

Since then, the IMM has repeatedly remarked on the “significant issues with PJM’s benefit/cost analysis that should be addressed prior to approval of additional projects,” reiterating in its annual reports that “PJM’s benefit/cost analysis includes only the decreases in costs to load and ignores the increases in costs to load associated with market efficiency projects.”⁶⁰

F. PJM’s 2014 Update To The Economic Project Selection Methodology Undermined And Conflicted With The Commission’s Reason For Approving The Methodology

As described earlier, the Commission accepted PJM’s 2007 Proposal due to the alignment of the project selection criteria with the cost allocation methodology: “[w]e find this approach reasonable because it would match the project selection process to the existing cost allocation method. That is, it would evaluate the load payment benefits of those loads that will be assigned the costs of the new facilities.”⁶¹ At the time, PJM only ignored zones with energy cost increases if the zone would not be allocated any costs. For regional facilities that would be cost allocated to all zones, PJM did not ignore cost increases for any zones.

⁵⁹ https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, page 2.

⁶⁰ https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-sec12.pdf, page 715.

⁶¹ PJM Interconnection, L.L.C., 123 FERC ¶ 61,051, P 67 (2008).

PJM's 2014 changes undermined the reasoning which supported the approval in the Commission's 2008 Order. Instead of only ignoring energy cost increases in zones if those zones would see no cost allocation, the present rules allocate cost to zones even if they would see cost increases. PJM simply removed the distinction in the definitions of "Load Energy Payment" and "Load Capacity Payment" that formerly had distinguished between the project selection criteria used by each cost allocation methodology. PJM addresses this change by claiming "this modification to the market efficiency benefit calculation will more appropriately align the benefits with the costs of the facilities by placing the cost of such upgrades on the zones where costs are being reduced."⁶² In practice, PJM's 2014 change only served to select more projects, and would then cost allocate those projects to zones if they saw no economic benefit through the load ratio share method, rather than placing the cost of the projects on zones that saw cost decreases.

Therefore, although the PJM economic project selection methodology is flawed in general, the 2014 changes exacerbate the flaw by "increas[ing] the number of projects that could qualify as a market efficiency project."⁶³

⁶² PJM Interconnection, L.L.C., Docket No. ER14-1394, at 8 (Filed February 28, 2014).

⁶³ *Id.*

G. PJM’s Project Selection Methodology Is Inconsistent With The Purpose Of Economic Project Selection

PJM seems to have deviated from the original filings creating the market efficiency planning process. In 2005, Congress made its intentions clear in the Energy Policy Act of the same year.⁶⁴ In the Energy Policy Act, Congress directed the Commission to create incentives inducing increased transmission “for the purpose of benefitting consumers by ensuring reliability and **reducing the cost of delivered power** by reducing transmission congestion.”⁶⁵ Further, it created the National Interest Electric Transmission Corridor (NIETC) program to reduce “congestion that adversely affects consumers.”⁶⁶ In both of these Congressional charges, Congress was concerned with congestion that actually harmed customers, namely, market inefficient congestion that could improve regional customer experience. PJM recognized this Congressional purpose in originally justifying its market efficiency planning process to the Commission.⁶⁷

PJM also recognized that, at the time, “the proposal does not ‘favor’ transmission solutions over generation solutions.”⁶⁸ In fact, PJM stated that the proposal would:

provide substantial information to market participants,
including the amount of generation and demand response

⁶⁴ Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) (“EPAAct”).

⁶⁵ 16 U.S.C. § 824s(a).

⁶⁶ 16 U.S.C. § 824p(a)(2).

⁶⁷ Answer of PJM Interconnection LLC, ER06-1474-000, at 6 (Filed October 18, 2006).

⁶⁸ *Id.* at 3.

that would alleviate constraints without the need for transmission upgrades. This will enable market participants to evaluate whether to provide market solutions to relieve congestion. If other market solutions come forward, alleviating congestion, then PJM will take them into account in developing and modifying its regional transmission plans accordingly.⁶⁹

The original recognition that generation and demand response are substitutes for transmission illustrates that if PJM does not account for zonal energy and capacity cost increases, it is not accurately reflecting the cost that could be avoided with that same local generation. By the same token, the exclusion of costs for zones that see price increases defeats the purpose of economic transmission planning in the first instance. When a utility's practice would defeat the purpose of the core reason behind the practice, it is unreasonable and should be rejected by the Commission.⁷⁰

PJM no longer provides information to the Transmission Enhancement Advisory Committee (TEAC) that would allow the replacement of rate-based transmission with local generation or demand response. PJM no longer allocates costs only to zones that receive benefits. With these carve outs, combined with the original failure to account for all costs, PJM has defeated the purpose of its economic planning regime. The Commission should remedy these deficiencies by

⁶⁹ *Id.* at 3-4.

⁷⁰ See e.g. *Calpine Corp., et al.*, 169 FERC ¶ 61,239, P 141 (2019) (rejecting as “unreasonable” arguments that would “defeat the purpose” of a utility rule).

ordering PJM to include an evaluation of all zonal costs in the project selection criteria. Once this change is implemented, PJM's method will reasonably select only those projects that are truly market efficient.

H. Alignment Of Benefits With Cost Allocation Is Not Sufficient Reason To Ignore Costs

The PA PUC does not dispute that the cost allocation of projects must be aligned with benefits. However, the costs to non-beneficiaries should not be entirely ignored. Regardless of who is paying for the transmission project, it is unjust and unreasonable for PJM to facilitate an unduly discriminatory race-to-the-bottom framework that allows for projects that increase aggregate consumer costs just so a subset of consumers can benefit.

In Zachary Ming's illustrative two-zone example that he created in his testimony titled *Table 2: Illustrative Two-Zone Example – Transmission Project Cost-Benefit Analysis*, attached to this Complaint, benefitting zones in PJM experience a net benefit of \$591 million (before the cost of the transmission itself) while non-benefitting zones experience a net cost of \$788 million.

PJM Method	Lower Voltage	ratio		1.97	Zone 2 Load Energy Payments NPV net benefit (\$591M) ÷ Transmission Project NPV cost (\$300M); project passes PJM 1.25 B/C threshold
	Regional	ratio		1.44	(50% × Zone 2 Load Energy Payments NPV net benefit (\$591M) + 50% × Production Cost NPV net benefit (\$276M)) ÷ Transmission Project NPV cost (\$410M); project passes PJM 1.25 B/C threshold
E3 Method	Lower Voltage	ratio		(0.66)	System Load Energy Payments NPV net benefit (-\$197M) ÷ Transmission Project NPV cost (\$300M); project does not pass
	Regional	ratio		0.13	(50% × System Load Energy Payments NPV net benefit (-\$197M) + 50% × Production Cost NPV net benefit (\$276M)) ÷ Transmission Project NPV cost (\$410M); project does not pass PJM 1.25 B/C threshold

As Mr. Ming observes:

Why not just skip the transmission project altogether simply take \$600 million from the non-benefitting zone and give it directly to the benefiting zone? Both zones would be better off than building the transmission. Clearly such a proposition is nonsensical, but the mere possibility that it exists demonstrates that the *status quo* can yield wasteful transmission investment.⁷¹

Second, under PJM’s current methodology, “regional” market efficiency projects allocate half of transmission costs to all zones, not just beneficiaries. This result shows that the cost allocation is not “aligned” with benefit determination. Forcing zones that experience higher energy costs from market efficiency projects to pay for the transmission lines themselves is unjust and unreasonable.

⁷¹ Direct Testimony of Zachary Ming at 26-27 A30.

VI. REMEDY

A. The Commission Should Order PJM To Revise Its Project Selection Methodology To Consider All Costs To All Zones

To rectify the unjustness, unreasonableness and unduly discriminatory nature of PJM's current framework, PJM should include the impact on all (benefitting and non-benefitting) zones when calculating consumer benefits. This approach will ensure non-discriminatory treatment between all PJM consumers.

The outcome of this change (aside from rectifying the inherent discrimination) will ensure that PJM does not approve projects that increase aggregate consumer costs in PJM. When the impacts to all consumers are considered, only projects that yield a net benefit to all consumers in aggregate will pass PJM's market efficiency test.

PJM should keep the existing formulas for Lower Voltage and Regional Projects and revise only the definitions of "Change in Load Energy Payment" and "Change in Load Capacity Payment" in Schedule 6, section 1.5.7 of the Operating Agreement.⁷² Specifically, PJM should delete the following sentence from the definition of Change in Load Energy Payment:

The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.⁷³

⁷² <https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf>.

⁷³ <https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf>, pp. 597-599.

PJM should also delete the following sentence from the definition of Change in Load Capacity Payment:

The Change in the Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.⁷⁴

With these deletions, PJM's existing benefit formulas would remain the same as they are currently, shown again in **Error! Reference source not found.** below. The only difference is that the benefit formulas will consider the *overall* benefit to PJM customers rather than only focusing on the subset of zones that benefit from the proposed transmission.

Table 1: Current PJM Market Efficiency Benefit Formulas

Project Type	Benefits Formula
Lower Voltage	Change in Load Energy Payment + Change Load Capacity Payment
Regional	$(0.5 * \text{Change in Total Energy Production Cost}) + (0.5 * \text{Change in Load Energy Payment}) + (0.5 * \text{Change in Total System Capacity Cost}) + (0.5 * \text{Change in Load Capacity Payment}),$

This proposed replacement rate would result in a just and reasonable market efficiency selection framework by eliminating the discriminatory treatment that makes PJM's current methodology unjust, unreasonable and unduly discriminatory. As discussed above, PJM's current methodology is unjust, unreasonable and unduly discriminatory because it excludes zones that experience a cost increase

⁷⁴ *Ibid.*

from the consumer benefit calculation while including zones that experience a cost decrease. This asymmetric treatment discriminates between PJM consumers based solely on whether they benefit from a proposed project. Removing the two sentences identified above eliminates this undue discrimination by requiring PJM to calculate consumer benefits on a system-wide basis, treating all zones the same regardless of whether they benefit or are harmed. This is also consistent with the practice of every other North American ISO and RTO reviewed in the Appendix: no other jurisdiction excludes zones with cost increases from its benefit calculation, regardless of the benefit metric—whether societal or consumer—utilized.

This remedy will not eliminate market efficiency projects in PJM. For lower voltage projects, where the benefit formula is based entirely on consumer costs, the PA PUC proposed remedy will only impede projects that would increase aggregate consumer costs across all PJM zones. For regional projects, where the formula weights consumer benefits at 50% alongside a 50% societal component, this remedy reduces the likelihood that a project passes on the strength of consumer benefits to a subset of zones alone. In both cases, the remedy ensures that the consumer component of PJM's benefit calculation reflects the actual impact on all PJM consumers.⁷⁵

⁷⁵ See Attachment A, Direct Testimony of Zachary Ming at pp. 8-13.

PA PUC expert witness Zachary Ming analyzed the Goalders Creek substation expansion, Museville-Smith Mountain upgrade, and the Multi-Driver project in the COMED-NIPSCO-AEP area. These are RTEP proposals 525, 733, and 644+908, respectively.⁷⁶ Of these three, the only impacted proposal would be 644+908, because it has non-benefitting zones measured over the course of the 15-year planning horizon. In fact, it only has one non-benefitting zone, which is COMED. However, to call it non-benefitting is an understatement: PJM estimates it would experience a significant increase in Gross Load Payment for each of the test years it modelled, as shown in Table 1.⁷⁷

Table 2: Change in Net Load Payment across All Zones for RTEP proposal 644+908

Year	Change in Net Load Payment (\$ millions)
2023	+\$15.78
2027	+\$14.33
2030	+\$22.72
2033	+\$17.30

⁷⁶ <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230110/item-05---2022-multi-driver-proposal-window-no-1-update.pdf>; <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-03---market-efficiency-update.pdf>. PJM Transmission Expansion Advisory Committee, 2022 Multi-Driver Proposal Window No. 1 Update (Jan. 10, 2023), available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230110/item-05---2022-multi-driver-proposal-window-no-1-update.pdf>; PJM Transmission Expansion Advisory Committee, Market Efficiency Update (Dec. 8, 2025), available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-03---market-efficiency-update.pdf>.

⁷⁷ See: [appendix---2022-multi-driver-window-1-recommended-solution-644-908-market-efficiency-zonal-summaries.pdf](#).

When extrapolated over the entire planning horizon, this increase in payments reaches almost \$150 million dollars, as estimated by the IMM. Consequently, taking this harm into account would drastically change the cost-benefit analysis for this project, such that it would no longer pass the 1.25 ratio threshold.⁷⁸

The current discriminatory methodology in selecting market efficiency projects can be solved by simple deletions to PJM's Operating Agreement. In Schedule 6, Section 1.5.7 of the Operating Agreement, PJM should delete the following language from the definitions of "Change in Load Energy Payment" and "Change in Load Capacity payment:"

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone without the Economic-based Enhancement or Expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the Economic-based Enhancement or Expansion)]
.... ~~The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.~~

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD without the Economic-based Enhancement or Expansion) * (the number of days in the

⁷⁸ See Attachment A, Direct Testimony of Zachary Ming at pp. 23-24.

study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]. ... ~~The Change in the Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.~~

The proposed deletions result in a reduction in the “Total Annual Enhancement Benefit” as part of PJM’s Benefit-Cost Ratio, effectively treating the increase in Load Energy Payment and Load Capacity Payment as a negative benefit to be included in the sum.

B. Alternatively, The Commission Could Order PJM To Treat Cost Increases For Zones In The Cost Side Of The Benefit-Cost Ratio

Instead of addressing the remedy by deleting the above-referenced language, the Commission could also order PJM to revise its Operating Agreement to add the increase in Load Energy Payment and Load Capacity Payment to the denominator of the Benefit-Cost Ratio, in the definition of Total Enhancement Cost. The resultant definition would be:

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the Economic-based Enhancement or Expansion **plus the Change in Load Energy Payment for the Zones that show an increase in the Load Energy Payment and Change in Load Capacity Payment for the Zones that show an increase in the Load Capacity Payment.**

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion **plus the Change in Load Energy Payment for the Zones that show an increase in the Load Energy Payment and Change in Load Capacity Payment for the Zones that show an increase in the Load Capacity Payment.**

So long as energy and capacity cost changes in all zones are accounted for in the project selection methodology, either treating the changes as a cost or as a negative net benefit are both just and reasonable and should not have a substantial outcome determinative effect. However, by treating the negative benefit on the cost side of the equation, the Economic Project selection criteria would procure marginally fewer projects. This is the case because a marginal transmission project would necessarily have a denominator that is smaller than the numerator. Decreasing the numerator by a marginal amount necessarily decreases the ratio by a smaller amount than if the denominator is increased by the same amount.

VII. FORMAL REQUIREMENTS

- A. Section 206(b)(1) – Clearly Identify The Action Or Inaction Which Is Alleged To Violate Applicable Standards Or Regulatory Requirements**
- B. Section 206(b)(2) – Explain How The Action Or Inaction Violates Applicable Statutory Standards Or Regulatory Requirements**
- C. Section 206(b)(3) – Set Forth The Business, Commercial, Economic Or Other Issues Presented By The Action Or Inaction As Such Relate To Or Affect The Complainant**

As detailed above, the project selection methodology used by PJM is unjust, unreasonable and unduly discriminatory because it selects transmission projects for construction even when they are not cost effective. PJM's Transmission Expansion Advisory Committee's 2025 reevaluation of Transource Project 9A selected from the 2014/2015 RTEP long term window, shows that the combined net cost of the project for the region including both positive and negative Energy Market and Reliability Pricing Benefits as well as the cost of the project itself was \$2.94 Billion. This figure represents the total capital investment required to build the transmission lines and facilities, factoring in 2024 RTEP Window 1 reliability solutions and other cost assumptions.⁷⁹ In other words, the combined net cost of the full project (Original + Alternate or Original + West Only) comes to

⁷⁹ See PJM's Transmission Expansion Advisory Committee's *Market Efficiency Transource Project 9A Update* dated June 4, 2025, at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250708/20250708-informational-only---transource-project-9a-update.pdf>. Last checked July 30, 2026.

\$2.94 billion, reflecting the sum of these capital expenditures. The cost breakdown of the 2025 reevaluation includes: (1) Original 9A: Benefit/Cost ratio 3.74, cost \$430.41 M; (2) Alternate 9A: Benefit/Cost ratio 3.42, cost \$584.57 M; and (3) 9A West Only: Benefit/Cost ratio 3.85, cost \$264.61 M.⁸⁰

D. Section 206(b)(4) – Make A Good Faith Effort To Quantify The Financial Impact Or Burden (If Any) Created For The Complainant As A Result Of The Action Or Inaction

In efforts to reduce congestion costs in the AP South area, Load Serving Entities in Pennsylvania located in several PJM zones including APS (Allegheny and West Penn Power), DUQ, FE-ATSI (Pennsylvania Power Co.), METED, PECO, PENELEC, PLGRP (PPL and UGI-Electric) in aggregate may through selected market efficiency projects be negatively affected by increases in Net Load Payments (NLP). Such increases in pricing in these zones located in Pennsylvania, will lead to increased rates for some Pennsylvania ratepayers. According to the Independent Market Monitor, those negative net benefits totaled \$851.67 million. Inclusion of those increased costs would have reduced the benefit cost ratio of the project from 2.48 to 0.70, meaning the project would not have passed PJM's selection criteria.⁸¹ As congestion costs fluctuate due to other factors including, for example, transmission upgrades, generation buildout, and load growth on either

⁸⁰ *Id.*

⁸¹ https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, p. 2.

side of the constraint, congestion is merely a market signal to address the siting of new generation, and load growth issues. Currently, the market efficiency selection criteria is unjust, unreasonable and unduly discriminatory. PJM's Operating Agreement should be amended to consider costs on both sides of the constraint in determining the inputs to the benefit/cost ratio.⁸²

E. Section 206(b)(5) – Indicate The Practical, Operational, Or Other Nonfinancial Impacts Imposed As A Result Of The Action Or Inaction

PJM's current methodology creates perverse incentives that compound the financial injury. By socializing data center-driven transmission costs to all ratepayers, it insulates states and utilities that attract speculative load growth from overbuilding and stranding asset risk while shifting those risks to neighboring states' ratepayers. It also distorts planning incentives: utilities are incentivized to build for speculative load because stranded asset risk falls on ratepayers, not shareholders, and phantom or duplicative load requests inflate forecasts further. Absent regional reform, state-level remedies like large load tariffs may worsen the problem by magnifying the incentive to overbuild while shifting costs to customers elsewhere in PJM. PA PUC is not aware of any practical, operational, or other nonfinancial impacts should its Complaint be granted. Although PJM's project selection criteria may select marginally more transmission projects than if it used a

⁸² See Attachment A, Zachary Ming's Direct Testimony at pp. 11-12.

full accounting of costs and benefits, because the Complaint would not affect Reliability Projects, there should be no material deleterious effect on reliability.

F. Section 206(b)(6) – State Whether The Issues Presented Are Pending In An Existing Commission Proceeding Or A Proceeding In Any Other Forum In Which The Complainant Is A Party, And If So, Provide An Explanation Why Timely Resolution Cannot Be Achieved In That Forum

The PA PUC is not aware of any existing Commission proceeding in which the issues in the Complaint are pending.

G. Section 206(b)(7) – State The Specific Relief Or Remedy Requested, Including Any Request For Stay Or Extension Of Time, And The Basis For That Relief

The Complaint describes the specific relief requested.

H. Section 206(b)(8) – Include All Documents That Support The Facts In The Complaint In Possession Of, Or Otherwise Attainable By, The Complainant, Including, But Not Limited To, Contracts And Affidavits

The PA PUC submits the Direct Testimony of Mr. Zachary Ming, Partner of E3 as Attachment A and his Curriculum Vitae as Attachment B.

I. Section 206(b)(9) – State (e) Whether The Enforcement Hotline, Dispute Resolution Service, Tariff-Based Dispute Resolution Mechanisms, Or Other Informal Dispute Resolution Procedures Were Used, Or Why These Procedures Were Not Used; (ii) Whether The Complainant Believes That Alternative Dispute Resolution (ADR) Under The Commission’s Supervision Could Successfully Resolve The Complaint; (iii) What Types Of ADR Procedures Could Be Used; And (iv) Any Process That Has Been Agreed On For Resolving The Complaint

The PA PUC communicated its concerns directly with PJM, which declined to introduce the proposed Operating Agreement, Schedule 6 revisions in the PJM stakeholder process through a Problem Statement and Issue Charge.

The PA PUC has not used other dispute resolution mechanisms as these would be unlikely to resolve the dispute. The PA PUC has not contacted the Enforcement Hotline or Dispute Resolution Service or made use of the tariff-based dispute resolution mechanisms. The PA PUC does not view these mechanisms to likely be productive in this dispute, as the issues involved in the Complaint are related to the unjustness, unreasonableness and unduly discriminatory nature of Schedule 6 in an Operating Agreement that is not in a Commission-approved tariff. It would take a supermajority vote of stakeholders to amend Schedule 6 of the Operating Agreement. Further, as PJM has declined to initiate a stakeholder proceeding on this issue and the current language may benefit some voting stakeholders, it is doubtful that a PA PUC initiated Issue Charge or Problem

Statement would be addressed by PJM stakeholders in a timely fashion with a favorable outcome as PJM is focused on other issues currently.⁸³

J. Section 206(b)(10) – Include A Form Of Notice Of The Complaint Suitable For Publication In The Federal Register In Accordance With The Specifications In § 385.203(d) Of This Part. The Form Of Notice Shall Be On Electronic Media As Specified By The Secretary

Attached to this complaint is a form of notice of Complaint that is suitable for publication in the *Federal Register* in accordance with Section 385.203 of the Commission's Rules of Practice and Procedure.

K. Fast Track Processing (Rule 206(b)(11))

Fast Track processing is not required for this Complaint. Nevertheless, PJM conducts Market Efficiency project selections on a yearly basis. The PAPUC requests that the Complaint be addressed expeditiously in order to avoid unnecessary and unreasonable costs being imposed on ratepayers through future transmission projects selected under PJM's current Market Efficiency methodology.

⁸³ See *Comments from PJM Interconnection, LLC*, Docket No. AD26-7-000 (July 14, 2026); *Notice Requesting Post-Conference Comment*, Docket No. AD26-7-000 (July 30, 2026).

L. Communications (Rule 203(b))

Pursuant to Rule 206(c), concurrent with its filing with the Commission, the PA PUC has served copies of this complaint by email on the contacts for PJM as listed on the Commission's list of Corporate Officials:

Christopher O'Hara
Senior Vice President,
General Counsel, Secretary and Chief Compliance Officer
PJM Interconnection, LLC
2750 Monroe Boulevard
Audubon, PA 19403
Telephone: (610) 635-3042
Email: christopher.ohara@pjm.com

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Mark J. Stanisz
Associate General Counsel
PJM Interconnection, L.L.C.
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Telephone: (610) 666-4707
Email: FERCeService@pjm.com

M. Section 206(h) – Fast Track processing.

PA PUC is not requesting fast track processing.

N. Submitted documents

1. Complaint

2. Attachment A: Direct Testimony of Mr. Zachary Ming

3. Attachment B: Curriculum Vitae of Mr. Zachary Ming

4. Certificate of Service

5. Notice of Complaint

O. Correspondence and Communications

All correspondence and communications in this docket should be addressed to the following individuals, whose names should be entered on the official service list maintained by the Secretary in connection with this proceeding:

Kriss E. Brown, Executive Deputy Chief Counsel

Tiffany Tran, Assistant Counsel

Law Bureau

Pennsylvania Public Utility Commission

400 North St., 3rd Floor

(717)787-5000

kribrown@pa.gov

tiftran@pa.gov

VI. Conclusion And Request For Relief

For these aforementioned reasons, the Pennsylvania Public Utility Commission requests that the Federal Energy Regulatory Commission declare PJM's Operating Agreement as unjust, unreasonable and unduly discriminatory and order PJM Interconnection, LLC to modify its Operating Agreement in accordance with the remedies requested herein.

Respectfully submitted,

/s/ Kriss E. Brown

Kriss E. Brown

Executive Deputy Chief Counsel

Pennsylvania Public Utility Commission

(717) 787-4518

kribrown@pa.gov

Dated: August 17, 2026

NOTICE OF COMPLAINT

(August 17, 2026)

Take notice that on August 17, 2026 pursuant to sections 206 and 306 of the Federal Power Act (FPA), 16 U.S.C. 824e and 825e, and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, 18 CFR 385.206, Pennsylvania Public Utility Commission (Complainant) filed a formal complaint against PJM Interconnection, LLC (PJM or Respondent) alleging that Schedule 6, Section 1.5.7 of the PJM's Operating Agreement produces unjust, unreasonable and discriminatory results, which the Commission must modify under FPA Section 206.

Complainant certifies that copies of the complaint were served on the contacts for PJM as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants. The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at <https://www.ferc.gov/>.

This filing is accessible on-line at <http://www.ferc.gov>, using the "eLibrary" link and is available for electronic review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Dated: August 17, 2026.

CERTIFICATE OF SERVICE

Pursuant to Commission Rules of Practice and Procedure Nos. 206(c) and 2010, I hereby certify that I have this 12th day of August, 2026, caused the foregoing document to be served upon the Corporate Officials of Respondent PJM Interconnection, LLC that are identified on the Commission's list maintained pursuant to 18 C.F.R. § 385.2010(k).

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ATTACHMENT A

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

Pennsylvania Public Utility Commission)	
Complainant,)	Docket No. EL26-____-000
)	
v.)	
)	
PJM Interconnection, LLC,)	
Respondent)	

DIRECT TESTIMONY

OF

ZACHARY MING

ON BEHALF OF THE PENNSYLVANIA PUBLIC UTILITY
COMMISSION

August 17, 2026

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AFFIDAVIT OF ZACHARY MING

1. Introduction

Q1. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A1. My name is Zachary Ming. My current position is Partner at Energy and Environmental Economics (“E3”). My business address is 44 Montgomery Street Suite 1250, San Francisco, California 94104.

Q2. PLEASE STATE ON WHOSE BEHALF YOU ARE FILING TESTIMONY.

A2. I am testifying as an expert witness in the areas of civil and environmental engineering, management science and engineering, and economics on behalf of the Pennsylvania Public Utility Commission (“PA PUC”).

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A3. I have a Bachelor of Science degree in Civil and Environmental Engineering (Atmosphere and Energy program) with a Minor in Economics, and a Master of Science degree in Management Science and Engineering (Energy track), both from Stanford University, California. For 13 years I have held various roles at E3, an energy consulting firm specializing in the economics of the electricity system where I am currently a Partner. In addition to full-time consulting work at E3, I have taught a graduate-level course for eight years at Stanford University titled *Electricity Economics*.

1 **Q4. PLEASE DESCRIBE YOUR QUALIFICATIONS AS IT RELATES TO THE**
2 **ECONOMIC EVALUATION OF TRANSMISSION.**

3 A4. In my role as a Partner at E3, I oversee projects involving transmission and resource
4 planning, marginal cost analysis, market design, and rate design. I have authored
5 several reports that evaluate the role that generation and transmission serve in
6 reliably and cost-effectively meeting long-term system needs, including *Resource*
7 *Adequacy for the Energy Transition: A Critical Periods Reliability Framework and*
8 *its Applications in Planning and Markets*,¹ *Long-Run Resource Adequacy under*
9 *Deep Decarbonization Pathways for California*² and *Net-Zero New England:*
10 *Ensuring Electric Reliability in a Low-Carbon Future*.³ I have also developed
11 methods that quantify how generation resources can avoid or defer investments in
12 transmission and distribution infrastructure.⁴ I have worked with utilities to develop
13 transmission rate designs that accurately reflect the costs of the customers being
14 served, including in Nova Scotia and Alberta. Most broadly, I lead E3 teams to
15 support clients to understand the current challenges facing the electricity system
16 and to implement solutions that are economic and reliable.

¹ https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf.

² https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf.

³ https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf.

⁴ https://www.ethree.com/wp-content/uploads/2025/02/2024-ACC-Documentation-v1b_clean.pdf.

1 **Q5. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY**
2 **REGULATORY COMMISSION (“FERC”)?**

3 A5. Yes, I have testified multiple times before FERC. My previous testimony has
4 covered various topics related to transmission, rate design and wholesale markets
5 in PJM, including the transmission tariff for co-located loads,⁵ the capacity market
6 price cap,⁶ the participation of reliability must run (“RMR”) units in the capacity
7 market,⁷ and PJM’s filing to use marginal effective load carrying capability
8 (“ELCC”) as the basis for resource accreditation in the capacity market.⁸ I have also
9 testified to FERC on behalf of MISO in their proposal to implement the direct loss
10 of load (“DLOL”) methodology for resource accreditation,⁹ and on behalf of
11 generators regarding the pay-for-performance construct in ISO-NE.¹⁰ Additionally,
12 I have testified before state, provincial, and territorial public utility commissions in
13 Oregon, Texas, South Carolina, Colorado, New Brunswick, and Puerto Rico on
14 topics relating to reliability, resource adequacy, market design, and rate design.

15 **Q6. WHAT IS THE PURPOSE OF THIS TESTIMONY?**

16 A6. The purpose of this testimony is to demonstrate why PJM’s current methodology
17 for quantifying the economic benefits of candidate market efficiency transmission
18 projects is unjust and unreasonable because it discriminates between consumers in
19 the PJM region. This discrimination occurs because PJM only considers the
20 economic impact of proposed market efficiency projects to benefitting consumers

⁵ Docket Nos. EL25-49-000, EL25-49-001, AD24-11-000, and EL25-20-000.

⁶ Docket EL25-46-000.

⁷ Docket EL24-148.

⁸ Docket ER24-99-000.

⁹ Docket ER24-1638.

¹⁰ Docket EL25-106-000

1 and ignores economic costs to non-benefitting consumers. The result of this
2 discrimination is market efficiency transmission projects that can increase
3 consumer costs in aggregate at a time when a focus on affordability is paramount.
4 My testimony proposes an alternative non-discriminatory methodology that
5 considers the economic impacts to all consumers in PJM.

6 **Q7. PLEASE PROVIDE AN OUTLINE OF YOUR TESTIMONY.**

7 A7. My testimony is organized as follows:

- 8 • In Section 2, I provide background on the PJM transmission planning process
9 with a particular focus on market efficiency projects;
- 10 • In Section 3, I outline why PJM's current method for quantifying the benefits
11 of candidate market efficiency projects is unjust and unreasonable because it is
12 discriminatory;
- 13 • In Section 4, I propose an alternative non-discriminatory methodology for
14 quantifying the benefits of market efficiency projects that considers the
15 economic impacts to all PJM consumers. Beyond my proposed replacement
16 rate, I also provide longer-term considerations for PJM in terms of evaluating
17 market efficiency projects; and
- 18 • In Section 5, I summarize my testimony and recommendations.

1 2. Background

2 **Q8. PLEASE PROVIDE AN OVERVIEW OF TRANSMISSION PLANNING IN PJM.**

3 A8. Transmission planning in PJM primarily occurs through the Regional Transmission
4 Expansion Plan (“RTEP”) process. This is a process run by PJM that identifies and
5 evaluates candidate transmission projects that meet various grid needs. Projects are
6 ultimately approved or rejected by the PJM Board after PJM evaluation and input
7 from stakeholders.

8 **Q9. WHAT TYPES OF PROJECTS ARE EVALUATED THROUGH PJM’S**
9 **TRANSMISSION PLANNING PROCESS?**

10 A9. PJM’s transmission planning process evaluates candidate projects that meet four
11 main categories of system needs:

- 12 • **Reliability:** PJM conducts power flow studies to identify potential future
13 reliability issues such as thermal overloads, voltage violations, and stability
14 concerns. PJM then develops transmission projects to addresses these
15 issues through “baseline” transmission upgrades.
- 16 • **Market efficiency:** Stakeholders can propose candidate transmission
17 projects designed to improve system economics that are not strictly
18 necessary for reliability purposes. PJM uses production cost modeling to
19 simulate how the system operates with and without candidate transmission
20 projects to forecast the economic benefit of the project.

- **Operational:** PJM evaluates projects that transmission owners identify that may not resolve explicit NERC reliability violations but may improve system operations. Examples include enhancing transfer capability between zones, improving PJM’s ability to manage resource outages, and ensuring the system can access sufficient flexibility from resources.
- **Public policy:** PJM evaluates projects that stakeholders propose that are necessary to achieve state or federal mandates, such as renewable portfolio standards. For example, PJM evaluates what transmission projects are required to deliver energy from new policy-driven resources (often remote renewables) to load centers.

Q10. PLEASE PROVIDE MORE DETAIL ON THE MARKET EFFICIENCY CATEGORY.

A10. In transmission planning, “market efficiency” projects are designed to improve system economics by facilitating the dispatch of the lowest cost generation. The configuration of the existing transmission system may, in some cases, prevent the lowest cost generation from dispatching due to constraints on the transmission system. The result is “congestion.” PJM says that its RTEP market efficiency planning process is designed to “identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact.”¹¹

¹¹ PJM Manual 14B: PJM Region Transmission Planning Process, <https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf>, page 53.

1 Transmission planners evaluate the benefits of candidate market efficiency
2 transmission projects through forward-looking analysis that compares grid dispatch
3 costs with and without the project.

4 **Q11. HOW DO MARKET EFFICIENCY PROJECTS RELATE TO THE BROADER**
5 **PURPOSE OF REGIONAL TRANSMISSION ORGANIZATIONS?**

6 A11. Before the creation of Regional Transmission Organizations such as PJM,
7 traditional vertically-integrated utilities operated under a cost-of-service regulatory
8 framework that required them to act prudently. One aspect of prudence entails that
9 utilities seek to provide electricity service to customers at the lowest reasonable
10 cost, subject to meeting standards such as reliability and environmental compliance.

11 The advent of Regional Transmission Organizations in many cases moved
12 the transmission planning function from individual member utilities to the Regional
13 Transmission Organization itself, but the objectives of least-cost planning remain
14 the same. FERC Order No. 890 explained that, when planning to serve load, a
15 prudent transmission provider should consider whether “transmission upgrades or
16 other investments can reduce the overall costs of serving native load,” including
17 upgrades that “reduce congestion (redispatch) costs or integrate efficient new
18 resources.”¹² So, in the context of PJM, it has an obligation to plan transmission in
19 a manner that minimizes the cost of electricity across the region.

¹² <https://www.ferc.gov/sites/default/files/2020-05/890.pdf>, page 310.

1 **Q12. WHAT ARE THE GENERAL METHODS USED ACROSS THE ELECTRICITY**
2 **INDUSTRY FOR QUANTIFYING THE ECONOMIC BENEFITS OF A MARKET**
3 **EFFICIENCY TRANSMISSION PROJECT?**

4 A12. There are two general approaches to quantifying the economic benefits of a
5 transmission project: a societal perspective or a consumer perspective.¹³ The choice
6 between these two perspectives is ultimately a policy decision about whose welfare
7 should be considered.

8 *A societal* approach quantifies the value of a candidate transmission project
9 to both producers (i.e., generators) and consumers (i.e., loads). The societal value
10 includes how much a transmission project can both decrease energy dispatch costs
11 and installed capacity costs. The decrease in dispatch costs is generally calculated
12 by running a production cost model with and without the candidate transmission
13 project and calculating the difference in total production costs between these two
14 cases. The decrease in capacity costs is generally calculated by quantifying how
15 much the transmission reduces the required quantity of installed capacity to meet
16 the reliability requirement due to improved sharing of capacity between
17 transmission zones.¹⁴

18 *A consumer* approach quantifies the value of a candidate transmission
19 project to loads and does not consider the impact to producers (i.e., generators). The
20 benefits to consumers in this approach are generally calculated by quantifying how
21 the *prices* that loads pay for electricity can change with and without the

¹³ <https://www.brattle.com/wp-content/uploads/2021/06/The-Benefits-of-Electric-Transmission-Identifying-and-Analyzing-the-Value-of-Investments.pdf>, page 4.

¹⁴ https://www.ercot.com/files/docs/2024/05/23/E3_ERCOT_Congestion_Cost_Savings_Test_for_Economic_Transmission_Report_March_2024.pdf, page 27.

1 transmission project. Price changes are also calculated using production cost
2 modeling. Within this general method, some common industry approaches account
3 for the fact that changing prices through reduced congestion may reduce the
4 revenues that ISOs collect by selling the financial rights to congestion. Since these
5 revenues are allocated to loads, reductions in these revenues are a cost to
6 consumers.¹⁵ It is important to note that the energy and capacity prices that
7 consumers pay for wholesale electricity are just one portion of the total rates that
8 consumers pay, with the other primary portions being the cost of transmission and
9 distribution to deliver the electricity.

10 These two general approaches (societal and consumer) can yield results that
11 differ quite dramatically from each other. For example, a candidate transmission
12 project could theoretically yield very little societal benefits but very large consumer
13 price benefits if it relieves a small amount of congestion on a particular constraint
14 that significantly reduces energy prices on the other side. On the other hand, it is
15 also possible for a candidate transmission project to provide societal benefits while
16 *increasing* overall energy prices, even before accounting for the cost of the
17 transmission project itself. This can occur when all of the societal benefits accrue
18 to producers (i.e., generators) through higher prices upstream of the new
19 transmission.

¹⁵ *Ibid.*

1 **Q13. HOW ARE THESE CALCULATED BENEFITS USED IN THE SELECTION OF**
2 **MARKET EFFICIENCY PROJECTS?**

3 A13. First, the transmission planner must select one (or a combination) of the benefit
4 approaches that I describe above as the economic benefits of the market efficiency
5 project. Second, the transmission planner must compare these benefits to the cost
6 of the candidate transmission project to calculate a benefit-cost ratio of the project.
7 To account for the uncertainty associated with forecasted benefits, many RTOs set
8 the required benefit-cost ratio threshold at greater than 1.0 (e.g., 1.25).

9 **Q14. HOW DOES PJM CURRENTLY EVALUATE AND SELECT MARKET**
10 **EFFICIENCY PROJECTS?**

11 A14. PJM forecasts benefits for a candidate market efficiency transmission project (as
12 described above) and calculates the net present value of these benefits over a 15-
13 year horizon. PJM then compares these benefits to the net present value of costs of
14 the transmission project over the same 15-year period. PJM requires a benefit-cost
15 ratio of greater than or equal to 1.25 for the project to move forward for approval
16 by the PJM Board.

17 **Q15. WHAT METHOD DOES PJM USE FOR CALCULATING THE BENEFITS OF**
18 **CANDIDATE MARKET EFFICIENCY TRANSMISSION PROJECTS.**

19 A15. PJM's methodology for calculating the benefits of candidate market efficiency
20 projects differs for "regional" projects (at or greater than 230 kV) and "lower
21 voltage" (also known as "subregional") projects (less than 230 kV).¹⁶ PJM's RTEP

¹⁶ Monitoring Analytics, "State of the Market Report for PJM," 2025 Annual State of the Market Report for PJM, pages 778 and 779.

1 and market efficiency studies often focus on 345 kV and above for major
 2 congestion relief. For regional projects, PJM uses a combination of both the
 3 “societal” and “consumer” approaches that I describe above. Specifically, PJM
 4 calculates the average of societal benefits and PJM’s version of consumer benefits
 5 for both energy and capacity markets (described below).¹⁷

6 For “lower voltage” projects, PJM simply uses their version of consumer
 7 benefits of the project.¹⁸

8 An illustration of these formulas is provided in Table 1 below.

9 **Table 1: Current PJM Market Efficiency Benefit Formulas**

Project Type	Benefits Formula
Lower Voltage	Change in Load Energy Payment + Change in Load Capacity Payment
Regional	$(0.5 * \text{Change in Total Energy Production Cost}) + (0.5 * \text{Change in Load Energy Payment}) + (0.5 * \text{Change in Total System Capacity Cost}) + (0.5 * \text{Change in Load Capacity Payment})$

10 Note: Under PJM’s current framework, the Change in Load Energy Payment and Change in Load
 11 Capacity Payment terms only include zones that show a decrease in payment (i.e., zones that
 12 benefit).

13 **Q16. PLEASE PROVIDE MORE DETAIL ON HOW PJM CALCULATES CONSUMER**
 14 **BENEFITS I.E., THE CHANGE IN LOAD ENERGY PAYMENT AND CHANGE**
 15 **IN LOAD CAPACITY PAYMENT.**

16 A16. PJM calculates consumer benefits by calculating the change in load energy payment
 17 and change in load capacity payment by zone.¹⁹ For some zones, load payments
 18 increase (which is a cost to those consumers) and in some zones load payments
 19 decrease (which is a benefit to those consumers). This observation that transmission

¹⁷ PJM refers to consumer costs as “load energy payments” or “load capacity payments”.

¹⁸ PJM Manual 14B: PJM Region Transmission Planning Process, <https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf>, page 112.

¹⁹ PJM calculates the impacts of transmission expansion across all zones in its footprint, including AECO, AEP, APS, BGE, COMED, DAY, DEOK, DOM, DPL, DUQ, EKPC, FE-ATSI, HTP, JCPL, METED, NEPT, OVEC, PECO, PENELEC, PEPCO, PLGRP, PSEG, RECO, and VFT (see [20230511 PJM Zone Map](#)). These zones generally correspond to load-serving entities (“LSEs”) or distribution utilities and are each associated with a locational marginal price (see [PJM Locational Marginal Pricing Map](#)).

1 expansion makes some consumers better off who are downstream of the candidate
2 transmission project and some worse off who are upstream of the candidate
3 transmission project is well-documented in the academic literature.²⁰

4 When calculating the total consumer benefits for both energy and capacity,
5 *PJM only includes zones that experience a benefit* (i.e., decrease in load
6 payments). In other words, PJM excludes zones from the overall benefit calculation
7 that experience an increase in their energy and capacity load payments.²¹

8 **Q17. WHAT IS THE RESULT OF EXCLUDING ZONES THAT EXPERIENCE**
9 **HIGHER LOAD PAYMENTS FROM PJM’S BENEFIT CALCULATION?**

10 A17. The simple result is that PJM’s benefit calculations for market efficiency projects
11 do not in fact represent consumer benefits for all consumers in the PJM region.
12 Instead, they just represent benefits for the subset of consumers who stand to benefit
13 from the project. As a result, PJM’s methodology by definition over-values
14 transmission to consumers in aggregate because it only considers the impact to
15 those who benefit; in some cases, it is possible for PJM’s methodology to show
16 consumer “benefits” for a transmission project that actually *increase* costs for

²⁰ For example, Baldick et al.

(https://www.analysisgroup.com/globalassets/insights/publishing/blue_ribbon_panel_final_report.pdf, page 24) remark:

“One last point to make with regard to benefits is that many transmission projects will not benefit everyone – at least in the short run – and can in fact negatively impact some network users due to the impact on energy prices. In the discussion above, for example, we focused on a local generator who is harmed by a decrease in local prices. There are also circumstances where an exporting region could experience an increase in prices. This would benefit producers and cost consumers in the exporting region. These impacts are transfers, but do represent a real cost to the generators or consumers involved, and therefore can raise opposition to individual projects based upon local interests.”

²¹ PJM Manual 14B: PJM Region Transmission Planning Process, <https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf>, pages 112 & 113.

1 consumers in aggregate across the PJM region. I provide an example to illustrate
2 this later in my testimony.

3 **Q18. IS THERE ANY PRECEDENT FOR PJM’S APPROACH OF ONLY INCLUDING**
4 **CONSUMER IMPACTS FOR A SUBSET OF CONSUMERS WHEN**
5 **EVALUATING COST-EFFECTIVENESS?**

6 A18. No. No other ISO in North America calculates consumer benefits for only a subset
7 of consumers. All ISOs that use a consumer benefit metric (many use a societal
8 benefit metric) include the impact to *all* consumers across their geographic
9 footprint. I provide more detail on the specific methodologies used by other ISOs
10 in the Appendix.

11 **Q19. WHAT IS PJM’S STATED RATIONALE FOR ONLY INCLUDING CONSUMER**
12 **IMPACTS FOR A SUBSET OF CONSUMERS?**

13 A19. PJM has provided at least two reasons for only including consumer impacts for a
14 subset of consumers.

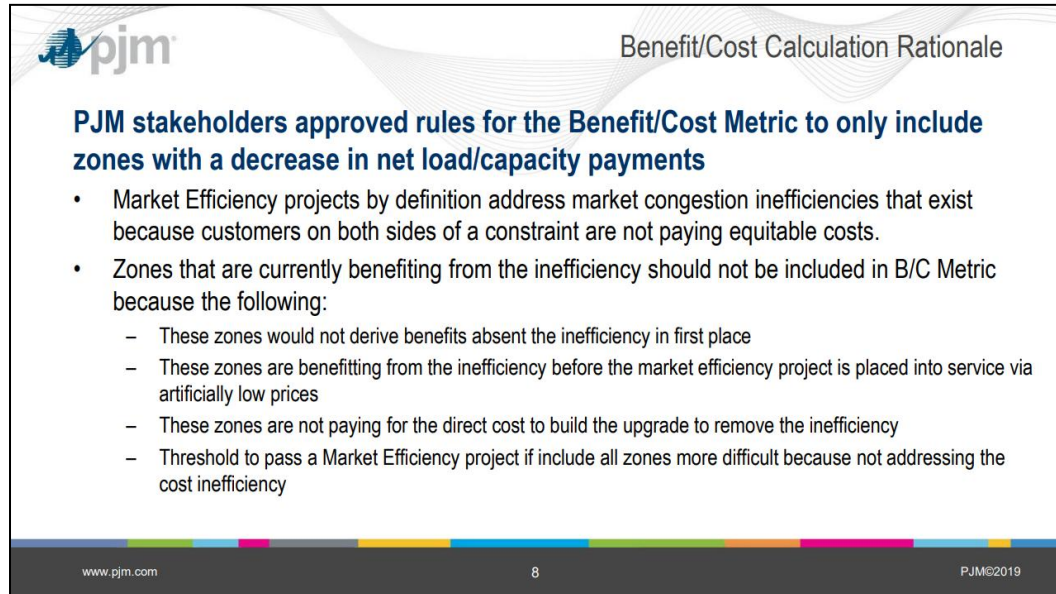
15 First, PJM has stated that “PJM believes this ... market efficiency benefit
16 calculation will more appropriately align the benefits with the [cost allocation] of
17 the facilities...”²² PJM’s argument appears to be that because benefitting zones pay
18 a larger (though not entire) share of market efficiency transmission projects than
19 non-benefitting zones, only the interests of benefitting zones should be
20 considered.²³

²² PJM Transmittal Letter, FERC Docket ER14-1394, 4/30/2014, page 8.

²³ The cost of regional facilities is allocated 50% based on load ratio share across the entire region and 50% to benefitting zones based on their share of the benefits
https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol2.pdf,
page 779.

Second, PJM has provided rationale that appears to characterize congestion as inherently inefficient and inequitable. This is shown in Figure 1.

Figure 1: PJM Market Efficiency Benefit/Cost Calculation Rationale²⁴



Q20. IS CONGESTION INHERENTLY INEFFICIENT?

A20. No, transmission congestion is *not* inherently economically inefficient. Some amount of congestion is a natural and economic characteristic of electricity systems. Seeking to eliminate congestion for its own sake results in transmission investments that cost more than the benefits of relieving the congestion. The Alberta Electric System Operator recently recognized this when it decided to “move away from the [then] current zero-congestion transmission planning standard to an optimally planned transmission planning standard.”²⁵ The Australian Energy Security Board²⁶ has also made similar observations before in saying:

²⁴ https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/mepetf/20190701/20190701-item-05-b-c-ratio-background.pdf?utm_source=chatgpt.com, page 8.

²⁵ <https://aesoengage.aeso.ca/optimal-transmission-planning>

²⁶ Comprised of the heads of the Australian Energy Market Commission, the Australian Energy Regulator, and the Australian Energy Market Operator.

1 *“That said, congestion is common in all regions of the [Australian National*
2 *Energy Market], and for good reason. Building transmission capacity is expensive*
3 *and imposes costs on the communities that the transmission lines run through. If*
4 *not carefully targeted, the cost of building transmission can very often exceed the*
5 *reduction in the cost of congestion. Just like we do not have unlimited numbers of*
6 *hotel rooms because building hotels is expensive, we also do not have unlimited*
7 *transmission capacity.”*²⁷
8

9 For these reasons, no ISOs or utilities currently plan transmission to
10 eliminate or reduce congestion for its own sake. Rather, ISOs and utilities only seek
11 to eliminate or reduce congestion when the cost of the transmission project is less
12 than the (avoided) cost of congestion. When the cost of congestion is less than the
13 cost of the transmission project required to relieve it, the congestion is economically
14 efficient.

15 **Q21. DOES CONGESTION YIELD “ARTIFICIALLY LOW PRICES” AS SUGGESTED**
16 **IN PJM’S SLIDE ABOVE?**

17 A21. PJM’s assertion that locational marginal prices that vary by location yield
18 “artificially low prices” is unfounded. Such an assertion is inconsistent with
19 economic theory and mischaracterizes how electricity markets are designed to
20 function. Prices at a particular location are not artificial but rather reflect the direct
21 result of serving load at a specific location while accounting for the physical
22 realities of transmission and generation. Prices that differ by location are a natural

²⁷ <https://www.datocms-assets.com/32572/1677794694-esb-congestion-management-cost-benefit-analysis.pdf>, page 16.

1 (not artificial) feature of an economically efficient electricity grid that minimizes
2 costs in aggregate for all consumers.

3 **Q22. DID FERC APPROVE PJM'S METHODOLOGY FOR ONLY INCLUDING**
4 **CONSUMER IMPACTS FOR A SUBSET OF BENEFITTING CONSUMERS?**

5 A22. FERC approved PJM's methodology through a "Delegated Letter Order" that was
6 issued by FERC staff under authority delegated by the Commissioners, rather than
7 standard Commission Order that is voted on and issued by the Commissioners
8 themselves.²⁸

²⁸ Delegated Letter Order, Docket No ER14-1394-000 (Issued April 23, 2014).

1 **3. Current Selection Framework is Unjust and Unreasonable**

2 **Q23. DOES PJM’S CURRENT METHOD FOR CALCULATING THE BENEFITS OF**
3 **MARKET EFFICIENCY TRANSMISSION PROJECTS CONSIDER THE**
4 **IMPACTS TO ALL PJM CONSUMERS IN A NON-DISCRIMINATORY**
5 **MANNER?**

6 A23. No. PJM’s methodology for calculating the benefits of market efficiency
7 transmission projects only considers the impacts to consumers in zones that are
8 beneficiaries (i.e. experience lower energy or capacity costs) while ignoring the
9 impacts to consumers in zones that experience higher costs. This discriminatory
10 treatment is unjust and unreasonable and is inconsistent with the mandate of the
11 Federal Power Act.

12 **Q24. WHAT IS THE FEDERAL POWER ACT’S STANDARD ON DISCRIMINATION?**

13 A24. The principle of treating all consumers equally was so important to Congress that
14 it mentions the principle of non-discrimination nineteen times in the Federal Power
15 Act. For example, it states that “no public utility shall ... make or grant any undue
16 preference or advantage to any person or subject any person to any undue prejudice
17 or disadvantage [or] maintain any unreasonable difference ... between localities.”²⁹

²⁹ Federal Power Act § 205(b), 16 U.S.C. § 824d(b).

1 **Q25. HOW DOES PJM'S METHODOLOGY VIOLATE THE FEDERAL POWER**
2 **ACT'S STANDARD ON DISCRIMINATION?**

3 A25. PJM's methodology for calculating the benefits of market efficiency projects only
4 considers the impacts to benefitting consumers and ignores the costs to non-
5 benefitting consumers. This methodology that does not equally consider the
6 impacts to all consumers in PJM is discriminatory and therefore unjust and
7 unreasonable.

8 By discriminating against a subset of loads, PJM has effectively excluded a
9 subset of consumers from their "consumer" benefits metric. Instead of planning
10 transmission in the public interest of all consumers, PJM is effectively acting in the
11 interests of a subset of consumers who would benefit from a particular project, even
12 at the expense of other consumers who may be made even worse off.

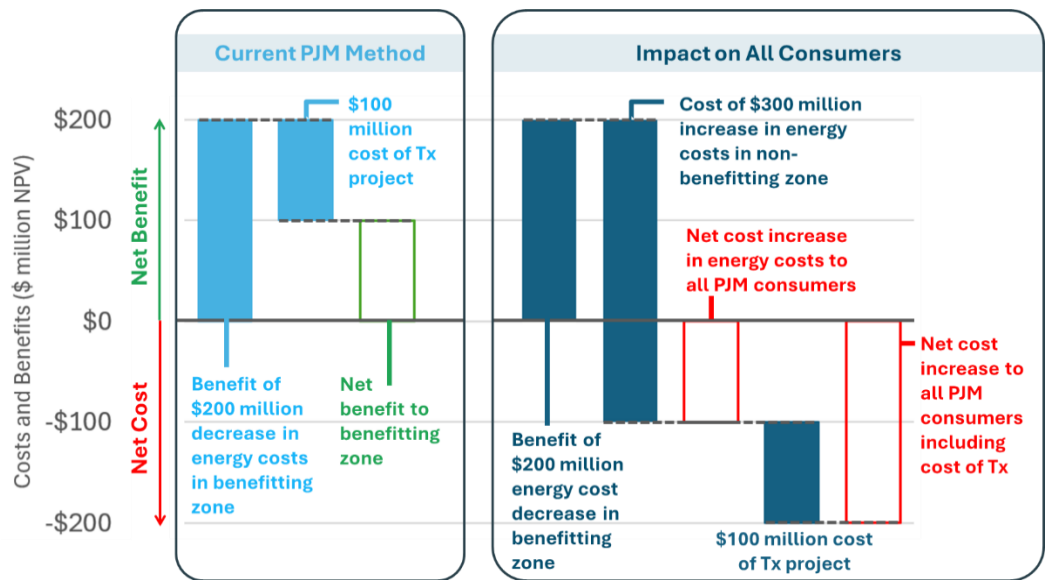
13 **Q26. WHAT IS THE RESULT OF PJM'S METHODOLOGY?**

14 A26. Aside from the unjustness of the discrimination itself, PJM's methodology over-
15 values transmission to consumers in aggregate because it only considers the impact
16 to those who benefit; in some cases, this methodology yields projects that **increase**
17 **costs for consumers in aggregate in PJM**, with costs defined as load energy and
18 capacity costs plus market efficiency transmission project costs. In fact, PJM's
19 methodology can even yield the non-sensical outcome of market efficiency projects
20 that increase load energy and capacity costs across the entire region *before* even
21 counting the cost of the transmission project itself. In other words, PJM consumers
22 in aggregate can be forced to pay for transmission projects that actually increase
23 their energy and capacity costs.

Q27. HOW CAN PJM’S METHODOLOGY YIELD MARKET EFFICIENCY PROJECTS THAT INCREASE CONSUMER COSTS IN AGGREGATE ACROSS PJM?

A27. Imagine a candidate market efficiency project that costs \$100 million and increases consumer energy costs in one zone by \$300 million and decreases consumer energy costs by \$200 million in another zone.³⁰ As illustrated in Figure 2, such a project would pass PJM’s market efficiency test but would increase energy costs for PJM consumers in aggregate. Including the cost of the transmission project itself would *further* increase costs for all PJM consumers.

Figure 2: Illustration of How PJM Method Can Increase Consumer Costs

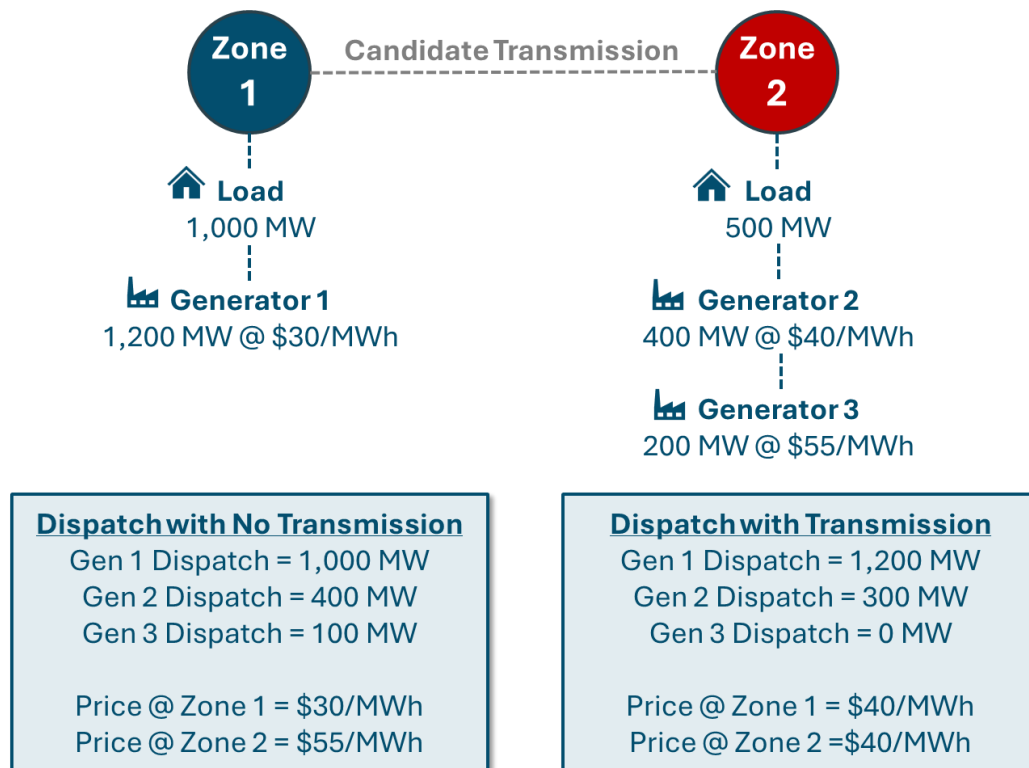


³⁰ All dollar values on a net present value basis

Q28. CAN YOU CREATE AN EXAMPLE SHOWING A MARKET EFFICIENCY PROJECT THAT WOULD BE APPROVED UNDER PJM’S CURRENT METHODOLOGY THAT INCREASES CONSUMER COSTS?

A28. Yes. I have constructed the simplest example possible to illustrate this potential outcome. The graphic below represents a two-zone electricity system with loads and generators in each zone. I have illustrated the dispatch and prices for a system *with* and *without* a candidate transmission project could connect these two zones. These values are explained more in the tables in the subsequent pages.

Figure 3: Two-Zone System Illustration



Using PJM’s existing methodology for evaluating candidate market efficiency projects, I demonstrate in the table below how PJM would calculate a benefit-cost ratio of greater than 1.25 for this project as either a “regional” or “lower voltage” project despite this project increasing consumer costs.

1 **Table 2: Illustrative Two-Zone Example – System Assumptions, Dispatch, and Cost per Hour**

		Units	Zone 1	Zone 2	System Total	Formula / Notes
System Assumptions						
Load		<i>MW</i>	1,000	500	1,500	Hourly load
Generator 1	Capacity	<i>MW</i>	1,200			Capacity of generator in Zone 1
	Marginal Cost	<i>\$/MWh</i>	\$30			Marginal cost of generator in Zone 1
Generator 2	Capacity	<i>MW</i>		400		Capacity of first generator in Zone 2
	Marginal Cost	<i>\$/MWh</i>		\$40		Marginal cost of first generator in Zone 2
Generator 3	Capacity	<i>MW</i>		200		Capacity of second generator in Zone 2
	Marginal Cost	<i>\$/MWh</i>		\$55		Marginal cost of second generator in Zone 2
Scenario A: No Transmission						
Generator 1 Dispatch		<i>MW</i>	1,000			Generator 1 serves all load in Zone 1
Generator 2 Dispatch		<i>MW</i>		400		Generator 2 dispatched at full capacity
Generator 3 Dispatch		<i>MW</i>		100		Generator 3 serves remainder of Zone 2 load
Locational Marginal Price (LMP)		<i>\$/MWh</i>	\$30	\$55		LMP = Marginal Cost of last unit dispatched in each zone
Load Energy Payments		<i>\$/hr</i>	\$30,000	\$27,500	\$57,500	Load × LMP
Generator Margins		<i>\$/hr</i>	\$0	\$6,000	\$6,000	Dispatch × (LMP - Marginal Cost), for each generator, summed by zone
Production Cost		<i>\$/hr</i>	\$30,000	\$21,500	\$51,500	Dispatch × Marginal Cost, for each generator, summed by zone
Scenario B: With Transmission						
Generator 1 Dispatch		<i>MW</i>	1,200			Generator 1 runs at full capacity to serve all load in Zone 1 and exports 200 MW to Zone 2
Generator 2 Dispatch		<i>MW</i>		300		Generator 2 serves 300 MW of Zone 2 load after 200 MW of imports from Zone 1
Generator 3 Dispatch		<i>MW</i>		–		Generator 3 is no longer needed; displaced by cheaper Generator 1 energy
Locational Marginal Price (LMP)		<i>\$/MWh</i>	\$40	\$40		LMPs equalize across zones; set by marginal unit across the regions (Generator 2). Relative to “No Transmission”, this increases prices in Zone 1 and decreases prices in Zone 2
Generator Margins		<i>\$/hr</i>	\$12,000	\$0	\$12,000	Dispatch × (LMP - Marginal Cost), for each generator, summed by zone
Load Energy Payments		<i>\$/hr</i>	\$40,000	\$20,000	\$60,000	Load × LMP by zone
Production Cost		<i>\$/hr</i>	\$36,000	\$12,000	\$48,000	Dispatch × Marginal Cost, for each generator, summed by zone

Table 3: Illustrative Two-Zone Example – Transmission Project Cost-Benefit Analysis

Benefits can be positive or negative depending on the item and are shown in green. Costs can be positive or negative and are shown in red.

		Units	Zone 1	Zone 2	System Total	Formula / Notes
Hourly Impact of Transmission (green cells represent benefits)						
Generator Margins		\$/hr	+\$12,000	– \$6,000	+\$6,000	Generator Margins from Scenario B minus Scenario A, for each zone; positive value represents an increase in margins, which is a benefit to generators
Load Energy Payments		\$/hr	+\$10,000	– \$7,500	+\$2,500	Load Energy Payments from Scenario B minus Scenario A, for each zone; positive value represents an increase in load energy payments, which is a cost to loads
Production Cost		\$/hr	+\$6,000	– \$9,500	– \$3,500	Production Cost from Scenario B minus Scenario A, for each zone; negative value represents a decrease in production costs, which is a benefit to society
Net Present Value (NPV) Calculation Input, Consistent with PJM Transmission Economic Evaluation						
Evaluation Period		years	15	15	15	15-year study horizon consistent with PJM Market Efficiency evaluation
Discount Rate		%	7.2%	7.2%	7.2%	Rate used to discount future benefits and costs (PJM's 2024/2025 discount rate)
Present Value (PV) Factor		factor	8.994	8.994	8.994	$(1 - (1 + \text{Discount Rate})^{-\text{Evaluation Period}}) \div \text{Discount Rate}$
NPV of Impact of Adding Transmission (green cells represent benefits)						
Generator Margins		\$M	+\$945	– \$473	+\$473	Hourly Generator Margins Impact $\times$ 8,760 hrs/yr $\times$ annuity factor (8.994); positive value represents an increase in margins, which is a benefit to generators
Load Energy Payments		\$M	+\$788	–\$591	+\$197	Hourly Load Energy Payment Impact $\times$ 8,760 hrs/yr $\times$ annuity factor (8.994); positive value represents an increase in load energy payments, which is a cost to loads
Production Cost		\$M	+\$473	–\$748	– \$276	Hourly Production Cost Impact $\times$ 8,760 hrs/yr $\times$ annuity factor (8.994); negative value represents a decrease in production costs, which is a benefit to society
Transmission Project Net Present Value (NPV) Costs						
Transmission Project NPV Costs		\$M			+\$300	Assumption: Present value of capital and fixed cost of the transmission project
Transmission Net Economic Benefits (green cells represent net benefits)						
Total Consumer Net Benefit		\$M			– \$497	System Load Energy Payments cost (\$197M) + Transmission Project Cost (\$300M); consumers experience \$497M net cost, which is a -\$497 net benefit
Total Societal Net Benefit		\$M			– \$24	Production Cost NPV net benefit (\$276M) – Transmission Project Cost (\$300M); society experiences \$24M net cost, which is a -\$24M net benefit
Benefit-Cost (B/C) Ratios						
PJM Method	Lower Voltage	ratio			1.97	Zone 2 Load Energy Payments NPV net benefit (\$591M) $\div$ Transmission Project NPV cost (\$300M); project passes PJM 1.25 B/C threshold
	Regional	ratio			1.44	$(50\% \times \text{Zone 2 Load Energy Payments NPV net benefit } (\$591\text{M}) + 50\% \times \text{Production Cost NPV net benefit } (\$276\text{M})) \div \text{Transmission Project NPV cost } (\$300\text{M})$; project passes PJM 1.25 B/C threshold
E3 Method	Lower Voltage	ratio			(0.66)	System Load Energy Payments NPV net benefit (-\$197M) $\div$ Transmission Project NPV cost (\$300M); project does not pass
	Regional	ratio			0.13	$(50\% \times \text{System Load Energy Payments NPV net benefit } (-\$197\text{M}) + 50\% \times \text{Production Cost NPV net benefit } (\$276\text{M})) \div \text{Transmission Project NPV cost } (\$300\text{M})$; project does not pass PJM 1.25 B/C threshold

1 **Q29. IS THE POTENTIAL FOR OUTCOMES LIKE THIS MERELY THEORETICAL?**

2 A29. No. There are multiple real-world projects in PJM where the concerns that I raise
3 above have occurred. For example, an enhancement proposed by Transource
4 Energy LLC (what PJM referred to as “Project 9A”), yielded the following results
5 as described by the PJM Independent Market Monitor (“IMM”):

6 *“Project 9A was considered a subregional project based on its voltage level,*
7 *meaning that changes in forecasted system costs were not considered for purposes*
8 *of estimating the benefit/cost ratios. Instead, only reductions in zonal load costs*
9 *were considered as a benefit of the project. Any increases in zonal load costs were*
10 *ignored in the analysis. The initial study had a benefit to cost ratio of 2.48, with a*
11 *capital cost of \$340.6 million. The sum of the positive (energy cost reductions)*
12 *effects was \$1,188.07 million. The sum of negative effects (energy cost increases)*
13 *was \$851.67 million. The net actual benefit of the project in the study was therefore*
14 *\$336.40 million, not the \$1,188.07 used in the study. Using the total benefits*
15 *(positive and negative) to compare to the net present value of costs, the benefit to*
16 *cost ratio was 0.70, not 2.48. The project should have been rejected on those*
17 *grounds.”³¹*

18
19 Another example is the “Project 644+908” Multi-Driver project in the
20 COMED-NIPSCO-AEP area, which was proposed as part of the 2022 Regional
21 Transmission Expansion Plan. The Independent Market Monitor once again
22 showed how the results would have drastically changed if PJM accounted for the
23 impact to all consumers rather than just the beneficiaries of the transmission:

24 *“The benefit/cost analysis used in the multi driver review is the same flawed*
25 *benefit/cost analysis that PJM uses for evaluating Market Efficiency projects.*
26 *PJM’s assumed benefit of the combined project was calculated as the sum of the*

³¹ https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, page 2.

1 *present value of positive (energy cost reductions to some loads) effects of \$169.8*
2 *million. The sum of the present value of negative effects (energy cost increases to*
3 *other loads), which was ignored in the PJM calculation of benefits, was \$149.1*
4 *million. The total benefit of the proposed multi driver project is therefore only*
5 *\$20.7 million, not the \$169.8 asserted by PJM, even ignoring the use of changes*
6 *in congestion rather than changes in production costs. Using the total positive and*
7 *negative effects to compare to the net present value of costs in the PJM's analysis,*
8 *the benefit/cost ratio is 0.24, not 1.99. All \$149.1 million of the increases in energy*
9 *costs (negative benefits) would be paid by load in the ComEd Zone. Based on the*
10 *requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi*
11 *driver project should have been rejected.”³²*

12 **Q30. BESIDES YOURSELF, HAVE OTHERS MADE ARGUMENTS THAT IT IS**
13 **UNJUST AND UNREASONABLE TO ONLY INCLUDE BENEFITS FOR A**
14 **SUBSET OF CONSUMERS IN THE PJM REGION?**

15 A30. Yes. The IMM has repeatedly raised this issue in its State of the Market and FERC
16 filings. For example, the IMM has stated that:

17 *“[t]he current rules governing the benefit/cost analysis of competing transmission*
18 *projects do not accurately measure the relative costs and benefits of transmission*
19 *projects. The current rules explicitly ignore the increased zonal load costs that a*
20 *project may create ... These flaws have contributed to PJM approving market*
21 *efficiency projects with forecasted, and realized, costs that are higher than the*
22 *forecasted benefits.”³³*

23 **Q31. ONE RATIONALE PJM HAS PROVIDED FOR ITS EXISTING**
24 **METHODOLOGY IS TO “ALIGN” THE MARKET EFFICIENCY BENEFIT**

³² Monitoring Analytics, “2024 State of the Market Report for PJM”, 2024 State of the Market Report for PJM, page 715. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf

³³ https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-162_20201110.pdf, page 2.

1 **DETERMINATION WITH COST ALLOCATION. IS THIS RATIONALE**
2 **COMPELLING?**

3 A31. No, this rationale is not compelling for two reasons.

4 First, regardless of who is paying for the transmission project, it is unjust
5 and unreasonable for PJM to facilitate a discriminatory race-to-the-bottom
6 framework that incentivizes consumers to pursue projects in their own interest that
7 ultimately increase costs for everybody. In other words, inefficiently building
8 transmission from one zone to another will decrease prices in the downstream zone.
9 This itself will increase the economics of building additional transmission to a yet
10 further downstream zone, which increases prices in the original downstream zone.

11 In the illustrative two-zone example that I created above, benefitting zones
12 experience an energy market benefit of \$591 million (before the cost of the
13 transmission itself) while non-benefititting zones experience an energy market cost
14 of \$788 million. Why not just skip the transmission project altogether and simply
15 take \$600 million from the non-benefititting zone and give it directly to the
16 benefitting zone? Both zones would be better off than building the transmission.
17 Clearly such a proposition is nonsensical, but the mere possibility that it exists
18 demonstrates that the status quo can yield wasteful transmission investment.

19 Second, under PJM's current methodology, "regional" market efficiency
20 projects allocate half of transmission costs to *all* zones, not just beneficiaries. This
21 shows that the cost allocation is not "aligned" with benefit determination by only
22 allocating costs to the zones that benefit. Forcing zones that experience higher
23 energy costs to pay for the transmission lines that cause them adds insult to injury.

1 Q32. ANOTHER RATIONALE PJM HAS PROVIDED FOR ITS EXISTING
2 METHODOLOGY IS THAT MARKET EFFICIENCY PROJECTS ADDRESS
3 “MARKET CONGESTION INEFFICIENCIES” AND THAT “ZONES THAT ARE
4 CURRENTLY BENEFITTING FROM THE INEFFICIENCY SHOULD NOT BE
5 INCLUDED IN THE B/C RATIO BECAUSE ... THESE ZONES WOULD NOT
6 DERIVE BENEFITS ABSENT THE INEFFICIENCY IN THE FIRST PLACE.”³⁴ IS
7 THIS RATIONALE COMPELLING?

8 A32. No. PJM’s rationale above appears to be implying that congestion is inherently
9 “inefficient” and that, by extension, less congestion is more efficient. However, as
10 I describe above, congestion itself is not necessarily inefficient, and in fact some
11 congestion *is* efficient. Economic efficiency seeks to maximize societal benefits.
12 To the extent that the cost of congestion is less than the transmission project
13 required to relieve it, then the congestion is efficient and is part of a least-cost
14 electricity system.

15 Q33. WHAT IS YOUR OVERALL ASSESSMENT OF PJM’S CURRENT
16 METHODOLOGY FOR CALCULATING THE BENEFITS OF MARKET
17 EFFICIENCY TRANSMISSION PROJECTS?

18 A33. PJM’s methodology for calculating the benefits of market efficiency transmission
19 projects is unjust and unreasonable because:

- 20 • It discriminates between benefitting and non-benefitting consumers;
- 21 • It can yield projects that increase aggregate consumer costs in PJM. At a
- 22 time when electricity system affordability is a paramount concern, it is

³⁴ https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/mepetf/20190701/20190701-item-05-b-c-ratio-background.pdf?utm_source=chatgpt.com, page 8.

1 unreasonable for PJM to use planning methods that unnecessarily increase
2 consumer costs;

- 3 • It has no precedent in any other RTO, each of which consider system-wide
4 impacts under either a societal or consumer benefits perspective.
- 5 • It does not recognize that some congestion is efficient and present in a least-
6 cost electricity system. It is for this reason that no utilities or RTOs in North
7 America seek to eliminate or minimize congestion for its own sake.

8

4. Proposed Replacement Rate

Q34. HOW SHOULD PJM RECTIFY THE SHORTCOMINGS OF THEIR CURRENT MARKET EFFICIENCY BENEFITS DETERMINATION FRAMEWORK?

A34. To rectify the unjust and unreasonable design of PJM's current framework, PJM should include the impact of all (benefitting and non-benefitting) zones when calculating consumer benefits of market efficiency projects. This approach will ensure non-discriminatory treatment between all PJM consumers.

Q35. WHAT IS THE OUTCOME OF YOUR PROPOSED CHANGE?

A35. The outcome of my proposed change (aside from rectifying the inherent discrimination) will very simply ensure that PJM does not overvalue market efficiency projects, avoiding the outcome where PJM identifies market efficiency projects that increase aggregate consumer costs in PJM.

Q36. PLEASE PROVIDE THE SPECIFIC CHANGE THAT PJM SHOULD IMPLEMENT IN ITS OPERATING AGREEMENT.

A36. To rectify the unjustness and unreasonableness of the current Operating Agreement, PJM should revise the definitions of "Change in Load Energy Payment" and "Change in Load Capacity Payment" in Schedule 6, Section 1.5.7 of the Operating Agreement.³⁵

Specifically, PJM should delete the following sentence from the definition of Change in Load Energy Payment:

³⁵ <https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf>.

1 *“The Change in the Load Energy Payment shall be the sum of the Change in the*
2 *Load Energy Payment only of the Zones that show a decrease in the Load Energy*
3 *Payment.”*³⁶
4

5 PJM should also delete the following sentence from the definition of
6 Change in Load Capacity Payment:

7 *“The Change in the Load Capacity Payment shall be the sum of the change in the*
8 *Load Capacity Payment only of the Zones that show a decrease in the Load*
9 *Capacity Payment.”*³⁷
10

11 With those deletions, PJM’s existing benefit formulas would remain the
12 same as they are currently, shown again in Table 4. The only difference is that the
13 benefit formulas will consider the *overall* benefit to PJM customers rather than only
14 focusing on the subset of zones that benefit from the proposed transmission.

15 **Table 4: Current PJM Market Efficiency Benefit Formulas**

Project Type	Benefits Formula
Lower Voltage	Change in Load Energy Payment + Change Load Capacity Payment
Regional	(0.5 * Change in Total Energy Production Cost) + (0.5 * Change in Load Energy Payment) + (0.5 * Change in Total System Capacity Cost) + (0.5 * Change in Load Capacity Payment)

16 **Q37. WOULD YOUR PROPOSED REPLACEMENT RATE RESULT IN A JUST AND**
17 **REASONABLE MARKET EFFICIENCY PROJECT SELECTION**
18 **FRAMEWORK?**

19 A37. Yes. The proposed replacement rate would result in a just and reasonable market
20 efficiency selection framework by eliminating the discriminatory treatment that
21 makes PJM's current methodology unjust and unreasonable.

³⁶ <https://www.pjm.com/pjmfiles/directory/merged-tariffs/oa.pdf>, pages 597-599.

³⁷ Ibid.

1 As discussed above, PJM's current methodology is unjust and unreasonable
2 because it excludes zones that experience a cost increase from the consumer benefit
3 calculation while including zones that experience a cost decrease. This asymmetric
4 treatment discriminates between PJM consumers based solely on whether they
5 benefit from a proposed project. Removing the two sentences identified above
6 eliminates this discrimination by requiring PJM to calculate consumer benefits on
7 a system-wide basis, treating all zones the same regardless of whether they benefit
8 or are harmed.

9 My proposed change is also consistent with the practice of every other
10 North American ISO and RTO reviewed in the Appendix. No other jurisdiction
11 excludes zones with cost increases from its benefit calculation, regardless of the
12 benefit metric—whether a societal or consumer perspective.

13 **Q38. WOULD IMPLEMENTING YOUR PROPOSED REPLACEMENT RATE TO THE**
14 **PJM OPERATING AGREEMENT HAVE ANY BROADER IMPLICATIONS ON**
15 **THE FRAMEWORKS USED IN OTHER RTO/ISO'S?**

16 A38. No. As the jurisdictional review in the Appendix demonstrates, PJM is currently
17 the *outlier* among all RTO/ISOs in its evaluation of market efficiency
18 transmission projects. No other RTO/ISO excludes zones with cost increases from
19 its benefit calculation. Rectifying this discriminatory treatment in PJM's current
20 framework would bring PJM's methodology in-line with other RTO/ISOs and
21 would not have any broader implications on the frameworks in other RTO/ISOs.

1 **Q39. WOULD YOUR REPLACEMENT RATE ELIMINATE OR IMPEDE MARKET**
2 **EFFICIENCY PROJECTS IN PJM?**

3 A39. My proposed replacement rate will not eliminate market efficiency projects in PJM.
4 For lower voltage projects (where the benefit formula is based entirely on consumer
5 costs), my proposed replacement rate would only eliminate projects that would
6 make consumers in aggregate worse off due to the combination of energy, capacity,
7 and transmission costs. For regional projects (where the benefit formula weighs
8 consumer and societal costs each at 50%), my proposed replacement rate would
9 impede projects that would make consumers in aggregate worse off but not entirely
10 eliminate these projects due to the consideration of societal benefits. In both cases,
11 my remedy ensures that the consumer component of PJM's benefit calculation
12 appropriately reflects the impact on all PJM consumers. Projects that reduce
13 consumer costs for all PJM consumers would not be impacted.

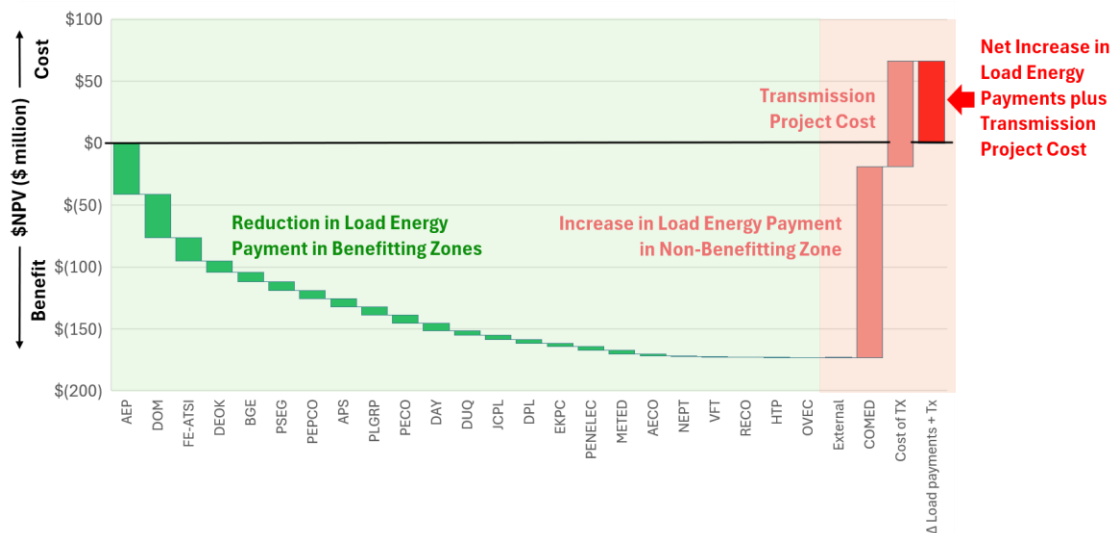
14 **Q40. WOULD RECENT MARKET EFFICIENCY PROJECTS BE IMPACTED BY**
15 **YOUR PROPOSED CHANGE?**

16 A40. I received data from PJM and reviewed three recent candidate market efficiency
17 projects that PJM evaluated in its recent Regional Transmission Expansion
18 Planning (RTEP) process. Of those, only one would have had a different approval
19 outcome under my proposed remedy.

20 Specifically, I analyzed the Goalders Creek substation expansion,
21 Museville-Smith Mountain upgrade, and the Multi-Driver project in the COMED-
22 NIPSCO-AEP area. These are RTEP proposals 525, 733, and 644+908,

1 respectively.³⁸ Of these three, the only impacted proposal would be 644+908 (the
 2 Multi-Driver project in the COMED-NIPSCO-AEP area). As the graph below
 3 shows, the cost to the non-benefitting zone (COMED) is nearly as large as the
 4 aggregate benefits to all benefitting zones, and once the cost of the transmission
 5 project itself is included this project results in a \$66 million net present value cost
 6 in aggregate on all PJM consumers.

7 **Figure 4: Costs and Benefits of COMED-NIPSCO-AEP Multi-Driver Transmission Project**



8 This analysis shows that every zone except COMED would experience a benefit
 9 (i.e. decrease in load payment), totaling approximately \$170 million; while
 10 COMED customers would experience a cost increase of around \$150 million. The
 11 aggregate load payment benefits to all zones are thus approximately \$20 million,
 12

³⁸ <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230110/item-05---2022-multi-driver-proposal-window-no-1-update.pdf>; <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-03---market-efficiency-update.pdf> PJM Transmission Expansion Advisory Committee, 2022 Multi-Driver Proposal Window No. 1 Update (Jan. 10, 2023), available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230110/item-05---2022-multi-driver-proposal-window-no-1-update.pdf>; PJM Transmission Expansion Advisory Committee, Market Efficiency Update (Dec. 8, 2025), available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-03---market-efficiency-update.pdf>.

1 which is significantly less than the \$85.5 million transmission project cost. This
2 finding that the costs of this transmission project outweigh the benefits is consistent
3 with the IMM's assessment of this project as I previously quoted.³⁹

4 Based on my analysis here, I reach the same conclusion as the IMM did:
5 this project should have been rejected, because after accounting for the impact to
6 *all* customers (including those harmed in COMED), the costs of the projects
7 outweigh the benefits.

³⁹ “Using the total positive and negative effects to compare to the net present value of costs in the PJM’s analysis, the benefit/cost ratio is 0.24, not 1.99.” Monitoring Analytics, “2024 State of the Market Report for PJM”, 2024 State of the Market Report for PJM, page 715.
https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf

1 **Long-Term Considerations**

2 **Q41. ARE THERE OTHER FACTORS THAT YOU WOULD RECOMMEND THAT**
3 **FERC CONSIDER IN SETTING POLICY FOR HOW PJM EVALUATES**
4 **MARKET EFFICIENCY PROJECTS?**

5 A41. Beyond the immediate remedy that I propose to rectify the unjust and unreasonable
6 flaw of the current PJM methodology, FERC should also consider more structural
7 changes to the framework that relate to long-term economic efficiency.

8 **Q42. PLEASE DESCRIBE THE CONCEPT OF “ECONOMIC EFFICIENCY” AS IT**
9 **RELATES TO TRANSMISSION.**

10 A42. “Economic efficiency” is a general concept in economics that refers to maximizing
11 societal value, or equivalently, minimizing societal costs. Notably, a framework
12 that evaluates economic efficiency captures impacts to all members of society:
13 producers and consumers.

14 As I describe above in the Background section, a common approach to
15 valuing market efficiency transmission projects quantifies the “societal” value of
16 how much a transmission project can decrease energy dispatch costs and installed
17 capacity costs. If the transmission project costs less than the societal benefits it
18 creates, it is economically efficient.

19 Because the societal benefits of transmission can differ from how consumer
20 prices change, any framework values transmission using consumer price benefits
21 has the potential to over or undervalue transmission relative to its societal value.
22 When transmission projects are overvalued relative to their societal value, this can
23 lead to transmission investments that are economically inefficient, meaning they

1 increase societal costs. When transmission projects are undervalued relative to their
2 societal value, this can lead to transmission projects not moving forward that have
3 the potential to decrease societal costs.

4 **Q43. DOES PJM'S METHOD THAT USES CONSUMER BENEFITS RESULT IN**
5 **PROJECTS THAT ARE ECONOMICALLY INEFFICIENT?**

6 A43. PJM's methodology can approve economically inefficient transmission projects
7 because it does not use societal benefits as the sole metric for quantifying the
8 benefits of market efficiency projects. Since societal value provides the economic
9 basis for efficiency, PJM's approach can (ironically) yield market efficiency
10 transmission projects that are not efficient.

11 **Q44. CAN YOU PROVIDE AN EXAMPLE OF USING SOCIETAL BENEFITS FROM**
12 **ANOTHER JURISDICTION?**

13 A44. Yes, MISO's methodology is a good counterexample. MISO evaluates economic
14 transmission projects through its annual MISO Transmission Expansion Plan
15 ("MTEP") process. Projects intended primarily to address economic needs are
16 designated Market Efficiency Projects ("MEPs"). To qualify, an MEP must satisfy
17 a minimum regional benefit-to-cost ratio of 1.25-to-1 using the benefit metrics
18 specified in Attachment FF-7 of the MISO Tariff. Benefits are evaluated over a
19 long-term planning horizon of up to 20 years.⁴⁰

⁴⁰ Midcontinent Independent System Operator ("MISO"), Open Access Transmission, Energy and Operating Reserve Markets Tariff; Transmission Expansion Planning Protocol: https://docs.misoenergy.org/miso12-legalcontent/Attachment_FF_-_Transmission_Expansion_Planning_Protocol.pdf, pages 40 – 43 and 513 – 518 (pdf).

1 The principal benefit metric is Adjusted Production Cost ("APC") savings,
2 which measures the reduction in total generation production costs across the MISO
3 footprint resulting from the project. APC savings are distinct from changes in load
4 energy payments, which reflect market settlement outcomes rather than changes in
5 underlying production costs. In addition to APC savings, MISO's tariff recognizes
6 other benefit categories, including avoided reliability project costs and certain
7 MISO-SPP settlement-related impacts, where applicable.

8 Importantly, APC benefits are calculated on a footprint-wide basis: in
9 computing the net benefits of a project, MISO sums APC savings across all zones,
10 whether a given zone's APC savings are positive or negative.⁴¹ Zones experiencing
11 increased production costs resulting from a project remain part of the analysis when
12 net benefits are determined. Only after the economic evaluation is complete does
13 MISO turn to cost allocation, where it looks solely to benefiting zones, allocating
14 MEP costs only to zones that exhibit a net positive present value of benefits over
15 the evaluation period.⁴²

16 **Q45. WHY DOES PJM USE CONSUMER BENEFITS INSTEAD OF SOCIETAL**
17 **BENEFITS FOR VALUING MARKET EFFICIENCY TRANSMISSION**
18 **PROJECTS?**

19 A45. The decision to use societal benefits (that promote economic efficiency) vs.
20 consumer benefits is ultimately a policy decision. In many cases, the decision to

⁴¹ MISO, Economic Planning Whitepaper, [MISO Economic Planning Whitepaper651689.pdf](#), 2024, page 23 (pdf).

⁴² MISO, Transmission Planning Business Practices Manual, BPM-020-r33: <https://cdn.misoenergy.org/BPM-020%20Transmission%20Planning113822.zip>, page 167 (pdf).

1 use consumer benefits is based on the motivation to minimize consumer costs,
2 without regard for the welfare of generators.

3 However, planning transmission that just focuses on consumer costs
4 without regard for the welfare of generators can actually have the unintended long-
5 run impact of *increasing* consumer costs. This is because this framework can create
6 a less attractive investment environment for generators. If a prospective generator
7 knows that the RTO will plan transmission with the goal of reducing market prices,
8 it may internalize this as a form of “regulatory risk” that subsequently increases its
9 cost of capital (entry). In the long-run, these higher investment costs will be passed
10 on to consumers, counter-acting the premise of planning transmission to their
11 benefit in the first place. For example, prominent energy economist Dr. Steven Stoft
12 remarks that:

13 *Investors take account of the cost of expropriations by factoring that*
14 *possibility into future investment decisions. This demonstration effect will*
15 *not be confined to the load pocket in question. It is impossible to predict*
16 *what the cost of this will be, but the resulting investment risk premiums will*
17 *affect the rate of return on all capital in the affected load pockets, not just*
18 *the new investment. This is a consequence of a market-clearing electricity*
19 *price. Probably the most sensible guess is that all of the money transferred*
20 *to load from existing generators will be lost to load through higher risk*
21 *premiums. In conclusion, it is inefficient to eliminate all congestion, and it*
22 *is wrong to focus on short-run consumer cost reductions when planning*
23 *transmission investments. As with any type of productive investment, the*
24 *goal should be to minimize the total cost of production and delivery. If the*
25 *market is competitive or the regulation effective, these costs savings will be*
26 *passed through to consumers.*⁴³

27
28 For this reason, economists often advocate for using societal benefits to
29 value transmission, because it makes the RTO a neutral party (“benevolent

⁴³ Transmission Investment in a Deregulated Power Market, Steven Stoft, Chapter 4 in Competitive Electricity Markets and Sustainability, 2006, page 6.

1 planner”) with respect to market participants, rather than a quasi-consumer-
2 advocate who plans the system in their specific interest.⁴⁴

3 **Q46. IN LIGHT OF THIS OBSERVATION, ARE THERE BROADER CHANGES TO**
4 **PJM’S MARKET EFFICIENCY PROJECT-SELECTION FRAMEWORK THAT**
5 **MAY WARRANT CONSIDERATION IN THE FUTURE?**

6 A46. Yes. While my proposed replacement rate does not recommend that PJM adopt the
7 use of societal benefits to value market efficiency transmission projects, this is an
8 option that PJM could consider in the future.

9 There are two ways that PJM could more directly consider societal benefits
10 of transmission. First, PJM could simply use societal benefits as the sole benefit
11 metric for valuing market efficiency transmission projects. Such an approach would
12 simply apply 100% weight to the production cost savings portion of the energy
13 market benefit and capacity market benefit, without separate weight or
14 consideration for changes in load customer payments. Another approach would use
15 societal costs as part of a two-part test. For example, PJM could require that a
16 candidate market efficiency project must be cost effective using both societal

⁴⁴ https://www.analysisgroup.com/globalassets/insights/publishing/blue_ribbon_panel_final_report.pdf. See pages 17 to 20. They specifically describe one of the fundamental principles of planning and cost allocation as follows:

“An appropriate standard of measurement of the benefits of transmission is aggregate societal benefits within the geographic region or market being examined. This is the same concept that economists use when they describe “social welfare.” It focuses on the question of whether a particular upgrade or set of transmission enhancements provide net positive benefits to the system being analyzed. It does not focus on who, within that system, benefits or loses from a particular investment. (Economists call these “distributional” impacts, or economic transfers from one group to another within the system being analyzed.) Certainly, economic transfers (including energy price effects pre- and post-introduction of a new transmission element in the system) can be considered as part of the analysis guiding allocation of costs, but these should be secondary to considerations of whether there are net benefits if the project is built in the first place.”

1 benefits *and* consumer benefits. This approach would ensure that PJM does not
2 build economically inefficient transmission (due to the societal benefits screen) or
3 transmission that increases consumer costs (due to the consumer benefits screen).

4 **Q47. WHY DO YOU NOT INCLUDE EITHER OF THESE AS RECOMMENDATIONS**
5 **IN YOUR PROPOSED REPLACEMENT RATE?**

6 A47. These broader policy design choices, while important for PJM to consider, are
7 distinct from the narrower defect of discriminatory treatment between PJM
8 consumers addressed in this testimony.

1 **5. Recommendations & Summary**

2 **Q48. IN LIGHT OF THE ARGUMENTS YOU MAKE, DO YOU HAVE A**
3 **RECOMMENDATION?**

4 A48. Yes. I recommend that FERC order PJM to consider the economic impact to all
5 zones (benefitting and non-benefitting) when calculating aggregate consumer
6 benefits for market efficiency transmission projects.

7 **Q49. PLEASE SUMMARIZE YOUR TESTIMONY.**

8 A49. Yes. The key takeaways of my testimony are:

- 9 • PJM evaluates "market efficiency" transmission projects designed to
10 improve system economics by allowing the lowest cost generation to
11 dispatch through reduced congestion;
- 12 • In valuing the consumer benefits of candidate market efficiency
13 transmission projects, PJM only includes the impacts to consumers that
14 experience a net benefit and exclude the impact to consumers that
15 experience a net cost;
- 16 • This unjust differentiation between different consumers in PJM is
17 discriminatory, and PJM's methodology is therefore unjust and
18 unreasonable;
- 19 • The result of this discrimination is market efficiency projects that overvalue
20 transmission and can increase aggregate consumer electricity costs in PJM;
- 21 • To rectify the unjust and unreasonableness of PJM's current framework,
22 PJM should simply include the economic impact of all zones (benefitting

1 and non-benefitting) when calculating consumer benefits. This approach
2 will ensure non-discriminatory treatment between all PJM consumers and
3 ensure that PJM does not build market efficiency transmission projects that
4 increase aggregate consumer electricity costs in PJM; and
5 • In the longer-term, PJM could also consider more structural changes to
6 valuing the benefits of market efficiency projects that focuses more on
7 societal benefits and less on consumer benefits.

8 **Q50. DOES THIS CONCLUDE YOUR TESTIMONY?**

9 A50. Yes.

Appendix: Jurisdictional Review

Jurisdictional Review of Select Transmission Project Economic Evaluation Frameworks in North America

This appendix reviews how other major ISOs and RTOs in North America evaluate economic transmission projects, which are analogous to PJM’s “Market Efficiency” project category. The review focuses specifically on two dimensions that are central to this testimony: (1) the benefit metric used, and (2) the zones included in the benefit calculation. This jurisdictional review is summarized in Table 5 below.

Table 5: Summary of Transmission Economic Evaluation Frameworks in North America

ISO/RTO	Program and Project Type	Benefit Metric	Zones Included
PJM (current)	Program: Regional Transmission Expansion Plan (RTEP) Project Type: Market Efficiency Projects	Lower Voltage: Consumer Load energy and capacity payments Regional: Hybrid of societal and consumer 50% Production and capacity cost savings and 50% load energy and capacity payments	Consumer: Benefitting zones only Societal: All zones
MISO	Program: MISO Transmission Expansion Plan (MTEP) Project Type: Market Efficiency Projects	Societal Production cost savings, avoided reliability project costs	All zones
SPP	Program: Integrated Transmission Plan (ITP) Project Type: Economic Projects	Societal Production cost savings (termed Adjusted Production Cost), any other quantifiable benefit	All zones
NYISO	Program: Comprehensive System Planning Process (CSPP) Project Type: Regulated Economic Transmission Projects (RETP)	Societal Production cost test required first	All zones
ISO-NE	Program: System Efficiency Needs Assessment (SENA) Project Type: System Efficiency Transmission Upgrades (SETUs)	Societal Production cost savings, avoided transmission losses, avoided future transmission investment	All zones
CAISO	Program: Transmission Planning Process (TPP) Project Type: Economic Projects	Consumer Load energy payment that excludes generator impacts	All zones
ERCOT	Program: Regional Transmission Plan (RTP) Project Type: Economic Transmission Projects	Both societal and consumer Production cost savings (societal) or load energy cost (consumer); project passes if either test passes	All zones
AESO	Program: Optimal Transmission Planning (OTP) Project Type: Economic Projects (effective 2027)	Societal Production cost savings, avoided capacity costs, and avoided reliability project costs	All zones

MISO

Planning Program

MISO evaluates economic transmission projects through its annual MISO Transmission Expansion Plan (“MTEP”). The MTEP is a non-siloed planning process that considers reliability, economic, and policy needs together across a range of future scenarios. Projects that address primarily economic needs are designated Market Efficiency Projects (“MEPs”). Projects that address a combination of economic, reliability, and policy needs are designated Multi-Value Projects (“MVPs”). This appendix focuses on the MEP category, which is most analogous to PJM's Market Efficiency projects.

Study Horizon & Methodology

Benefits are evaluated over a long-term horizon of up to 20 years. MISO uses multiple future scenarios to account for uncertainty in load growth, fuel prices, and generation mix. The analysis uses capacity expansion modeling to identify the resource portfolio in each scenario, followed by production cost modeling to quantify dispatch savings.

Benefit Metric

MISO uses a societal benefit metric. The primary benefit measure is production cost savings, which is the reduction in the total cost of generating electricity across the footprint, calculated by comparing dispatch costs with and without the candidate project. Production cost savings are different than changes in load energy payments; the two measure different things and cannot be combined.

Zone Inclusion

Benefits are calculated across all zones in the MISO footprint. Zones that experience higher production costs as a result of the project are included in the analysis and their negative impacts are not excluded from the benefit calculation. The distribution of production cost savings across zones does inform cost allocation: zones that experience a net cost increase are not required to pay for MEPs, while all customers share the cost of MVPs.

SPP

Planning Program

SPP evaluates economic transmission needs through its annual Integrated Transmission Plan (“ITP”). The ITP assesses reliability, economic, and policy needs in parallel. For economic needs, SPP identifies transmission constraints that create significant, recurring congestion costs and evaluates candidate projects to relieve those constraints. Candidate projects must demonstrate cost-effectiveness over both a near-term and a long-term horizon to be included in the final portfolio of recommended projects.

Study Horizon & Methodology

1 SPP evaluates benefits in select study years: years 2, 5, and 10 of the planning
2 horizon. Results are linearly interpolated between study years and extended out to
3 a 40-year horizon. The analysis uses up to three futures to account for uncertainty
4 in key variables such as load growth and generation mix.

5 **Benefit Metric**

6 SPP uses a societal benefit metric. The primary measured benefit is the reduction
7 in total production costs, known as Adjusted Production Cost (“APC”) savings,
8 calculated across all SPP pricing zones. The “adjustment” refers to accounting for
9 purchases and sales of energy with other balancing authorities. SPP may also
10 consider other quantifiable benefits where data supports them, though additional
11 benefit categories are not enumerated with the same specificity as in MISO.
12 Capacity cost savings are not a separately identified benefit category in SPP’s
13 economic project evaluation framework.

14 **Zone Inclusion**

15 APC savings are calculated across all SPP pricing zones. Zones that experience
16 higher costs as a result of a candidate project are not excluded from the calculation.
17 The benefit reflects the net system-wide change in dispatch costs.

18

19 **NYISO**

20 **Planning Program**

21 NYISO evaluates economic transmission needs through the Congestion
22 Assessment and Resource Integration Study (“CARIS”), the economic planning
23 component of its Comprehensive System Planning Process (“CSPP”). CARIS
24 identifies and ranks congested transmission elements across a 10-year planning
25 period and evaluates the cost-effectiveness of generic solutions, including
26 transmission, generation, demand response, and energy efficiency, using the
27 Production Cost Savings Test as the primary benefit metric. When CARIS
28 identifies a cost-effective need, developers may propose specific projects to address
29 it.

30 **Study Horizon & Methodology**

31 The CARIS study is conducted using a forward-looking production cost model over
32 a multi-year planning window. NYISO does not specify a fixed study horizon for
33 economic projects in the same way as other ISOs reviewed here.

34 **Benefit Metric**

35 NYISO uses a societal benefit metric for its primary economic evaluation. The
36 Production Cost Savings Test is the key metric used in CARIS: it measures the
37 system-wide reduction in dispatch costs that would result from addressing
38 identified congestion and is the basis on which NYISO evaluates and ranks generic
39 solutions. NYISO also calculates a system-wide Gross Load Cost metric, which
40 measures the change in total consumer energy payments, but this is used for
41 informational purposes only and does not determine whether a solution advances.

1 Only after a solution is identified as cost-effective through CARIS does NYISO
2 proceed to the separate RETP cost recovery process. In this step, a proposed project
3 must demonstrate that the sum of zonal load savings in benefitting zones exceeds
4 the project's revenue requirement, and an 80% supermajority of beneficiary load
5 must vote to proceed before regulated cost recovery is granted.

6 **Zone Inclusion**

7 All zones are included in the CARIS region-wide production cost test, including
8 those that experience cost increases. Zones harmed by a project are not excluded
9 from the benefit calculation; their negative impacts reduce the measured net benefit
10 and can cause a project to fail the test.

11 The RETP cost recovery eligibility determination considers only zones with net
12 load savings, for the purpose of assessing whether sufficient beneficiary support
13 exists for regulated cost recovery. Zones harmed by a project bear none of the costs
14 and have no vote, but their welfare is fully reflected in the CARIS economic
15 evaluation that precedes the cost recovery process.

16

17 **ISO-NE**

18 **Planning Program**

19 ISO-NE evaluates economic transmission needs through its System Efficiency
20 Needs Assessment (“SENA”), governed by Section 17 of Attachment K of the
21 Open Access Transmission Tariff. Projects that address economic needs are
22 designated System Efficiency Transmission Upgrades (“SETUs”), formerly called
23 Market Efficiency Transmission Upgrades (“METUs”). ISO-NE identifies
24 congested transmission elements and evaluates candidate upgrades through a
25 competitive request for proposal (“RFP”) process when annual congestion costs
26 exceed the tariff threshold (currently \$4.3 million per year).

27 **Study Horizon & Methodology**

28 ISO-NE evaluates candidate upgrades over a 10-year planning horizon using a two-
29 pass production cost model. For each candidate transmission project, ISO-NE
30 compares production costs for the region with and without the proposed upgrade.
31 A single study year, corresponding to the last year of the 10-year horizon, is used
32 as the basis for the benefit calculation. Results are converted to a present value for
33 comparison against project costs.

34 **Benefit Metric**

35 ISO-NE uses a societal benefit metric. The primary benefit measure is production
36 cost savings across the full New England system and the surrounding NPCC region.
37 In addition to production cost savings, ISO-NE includes two supplemental benefit
38 categories: avoided transmission losses (the reduction in energy wasted in
39 transmission as a result of the upgrade) and avoided future transmission investment
40 (the cost of other planned transmission upgrades that are no longer needed because
41 of the candidate project). Capacity cost savings are not a separate benefit category
42 in ISO-NE's economic project evaluation framework.

Zone Inclusion

Production cost savings are calculated on a system-wide basis across all New England load zones. No zone is excluded from the analysis on the basis that it experiences a cost increase as a result of the candidate project. Cost allocation for approved SETUs follows a load-ratio basis across the full region, consistent with ISO-NE's principle that all consumers benefit from improvements to the interconnected regional network.

CAISO

Planning Program

CAISO evaluates economic transmission needs through its annual Transmission Planning Process ("TPP"), which addresses reliability, policy, and economic needs in an integrated planning cycle approved by the CAISO Board of Governors. Within the TPP, economic needs are identified through Economic Planning Studies that assess congestion and evaluate candidate projects.

Study Horizon & Methodology

CAISO conducts production cost studies for two study years: 5 years and 10 years after the project in-service date. Benefits for the years between the 5-year and 10-year studies are estimated through linear interpolation. Beyond 10 years, benefits are held constant at the 10-year value. Net present values are then calculated over the expected lifetime of the project. CAISO also evaluates sensitivity scenarios by varying key assumptions such as load growth, fuel prices, and hydro conditions, depending on data availability for the specific project.

Benefit Metric

CAISO uses a consumer benefit metric for planning purposes, assessed through the Transmission Economic Assessment Methodology ("TEAM"), which CAISO has used since 2004. Although TEAM was originally designed to assess multiple perspectives including a full societal one, CAISO has in practice relied on the ratepayer perspective, which measures the net change in what electricity consumers pay and excludes the welfare of merchant generators. The rationale is that ratepayers bear the cost of transmission investment and their welfare is therefore the relevant measure for planning decisions. For inter-regional projects with impacts extending beyond the CAISO footprint, CAISO also considers a broader regional societal perspective.

Zone Inclusion

Although CAISO uses a consumer benefit metric rather than a societal one, it does not discriminate among ratepayers based on whether they benefit from a project. The ratepayer benefit calculation reflects the net change in consumer costs across all pricing zones in the CAISO footprint, including zones that experience higher costs. No zone is excluded from the calculation because it experiences a cost increase.

ERCOT

Planning Program

ERCOT evaluates economic transmission needs through its annual Regional Transmission Plan (“RTP”). The RTP addresses both reliability and economic needs. Economic analysis is conducted for select future study years within the planning horizon. Candidate projects are identified based on their potential to address significant, recurring congestion, and benefits and costs are compared on a present-value basis.

Study Horizon & Methodology

ERCOT evaluates benefits in select future study years chosen to represent a range of plausible system conditions. Results for each study year are levelized and discounted to a present value over the expected life of the project.

Benefit Metric

ERCOT uses a dual-test framework: it calculates both system-wide production cost savings and system-wide consumer energy cost savings. Capacity cost savings are not a separate benefit category in either test. A project is recommended if it passes *either* test. The rationale for including the consumer energy cost test alongside the production cost test is that load bears 100% of transmission costs in ERCOT, giving consumer impacts particular weight in planning decisions. Including the production cost test alongside the consumer test ensures that projects that only transfer wealth from generators to consumers, without creating system-wide efficiency gains, still face scrutiny.

Zone Inclusion

Both the production cost test and the consumer cost test are calculated on a system-wide basis across all ERCOT zones. Neither test excludes zones that experience cost increases as a result of the project. The net system-wide change is used in both cases.

AESO

Planning Program

The Alberta Electric System Operator (“AESO”) is transitioning to a new Optimal Transmission Planning (“OTP”) framework, effective in 2027. Historically, Alberta operated under a planning standard that required the near-elimination of transmission congestion regardless of cost. The OTP framework replaces this with an economic planning standard that requires the AESO to weigh the benefits of transmission expansion against its costs, in recognition that some congestion is efficient when the cost of relieving it exceeds the benefits of doing so.

Study Horizon & Methodology

1 Under the OTP framework, benefits will be evaluated over a long-term planning
2 horizon using multiple future scenarios, consistent with a least-regrets planning
3 approach. The analysis will draw on capacity expansion modeling to determine the
4 evolving resource mix and production cost modeling to quantify dispatch savings.
5 The specific study years and scenario methodology are still being finalized as part
6 of the 2027 implementation.

7 **Benefit Metric**

8 The OTP framework uses a societal benefit metric. Benefit categories include
9 production cost savings, avoided capacity costs, and avoided reliability project
10 costs, which are consistent with the benefit categories used by MISO. The
11 framework is designed as a total-surplus analysis that does not prioritize the welfare
12 of any particular class of market participant. The specific weighting and
13 methodology for combining these benefit categories are still being finalized as part
14 of the 2027 implementation.

15 **Zone Inclusion**

16 Benefits are assessed across the entire Alberta footprint. No zone or class of market
17 participant is excluded from the analysis or given preferential weight. The
18 framework does not differentiate between benefitting and non-benefitting zones for
19 purposes of the benefit-cost determination.

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

Pennsylvania Public Utility Commission)
Complainant,)
)
v.)
)
PJM Interconnection, LLC,)
Respondent)

Docket No. EL26-____-000

CERTIFICATE OF ZACHARY MING

I, Zachary Ming, declare under penalty of perjury that I am the author of the foregoing testimony, that the facts set forth herein are true and correct to the best of my knowledge, and that if asked the same questions contained in the text, I would give the answers contained in the testimony.

/s/ Zachary Ming

August 17, 2026

Zachary Ming

Dated

ATTACHMENT B

ENERGY AND ENVIRONMENTAL ECONOMICS, INC.

San Francisco, CA

Partner

Mr. Ming leads E3's market design practice, with an emphasis on electricity systems operating under higher penetrations of renewable energy. He also has extensive expertise in resource planning, reliability and resource adequacy, regulatory and rate design issues, and distributed resource cost effectiveness. Recent projects include testifying before the Puerto Rico Energy Bureau on the topic of cost allocation and rate design, testifying before the Public Service Commission of South Carolina on PURPA rates, and testifying before the New Brunswick Energy & Utilities Board on cost allocation. Mr. Ming has also authored white papers for the Regulatory Assistance Project on rate design and worked with utilities to develop innovative new rates such as wholesale rates to facilitate flexible green hydrogen customers in Nova Scotia. Mr. Ming has testified before FERC on six different topics and has testified before regulators in Texas, Colorado, Oregon, South Carolina, New Brunswick, and Puerto Rico. Mr. Ming has been the lead author on several high-profile resource planning studies including *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California* and *Resource Adequacy in the Pacific Northwest*.

Mr. Ming teaches a graduate level course at Stanford University titled *Electricity Economics* that provides a foundation of economic principles on the topics of regulation, planning, and operation of electric utilities, with a particular emphasis on emerging electricity sector topics such as renewable energy, energy storage, distributed resources, and market design. Mr. Ming holds an M.S. in management science and engineering (energy and environment track) and a B.S. in civil and environmental engineering (atmosphere and energy) from Stanford University.

Select projects at E3 include:

- **Puerto Rico Energy Bureau, Cost of Service and Rate Design Expert Support, 2025:** Mr. Ming wrote and submitted an expert report to the Puerto Rico Energy Bureau on cost allocation and rate design, advising the Bureau on these topics in support of LUMA's 2025 rate case — the first such proceeding since 2015. E3 supported the Bureau and Hearing Examiner, serving as lead expert on cost allocation, revenue allocation, and rate design, including evaluating LUMA and stakeholder filings and developing background training materials for the Bureau.
- **PJM Transmission Tariff, Constellation, 2025:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on the co-location of loads with generators in PJM. The testimony identifies three configurations of co-located loads (firm, generator-contingent, and interruptible) each uniquely impacting transmission costs and reliability. The testimony proposes targeted tariff structures that align with rate design principles.
- **Transmission Rate Design Analysis, AltaLink, 2017-2021:** Mr. Ming conducted rate design and regulatory analysis on the existing wholesale transmission tariff in Alberta and proposed alternative designs that were more aligned with cost-of-service principles.
- **Reliability Risk Model Assessment, PJM, 2021-2025:** Mr. Ming led a team that provided a detailed technical review of the probabilistic reliability risk model used by PJM to calculate capacity requirements and resource accreditation values (including renewables, storage, and thermal) for use in

the PJM capacity market. Elements of the model that were reviewed include data inputs, assumptions, algorithms, methods of use, and results. Through this process, E3 made multiple suggestions for improvement to PJM staff.

- **PJM Marginal Effective Load Carrying Capability Testimony, Calpine, 2023:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission supporting PJM’s proposal to accredit the capacity of resources in the capacity market using a marginal effective load carrying capability (marginal ELCC methodology). Mr. Ming argued that this approach would 1) ensure reliability 2) provide economically efficient signals for entry and exit 3) was fair and technology-neutral and 4) was simple and acceptable.
- **PJM Capacity Market Price Cap Testimony, Calpine, 2025:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on the appropriate price cap in the PJM capacity market. Mr. Ming argued that a reduced price cap would hinder the ability of the market to deliver long-term reliability goals. In subsequent testimony, Mr. Ming argued that any reduction in price cap should be accompanied by an increase in the price floor, a settlement that was ultimately adopted.
- **PJM Reliability Must Run Testimony, Calpine, 2024:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on the participation of reliability must run (“RMR”) units in the PJM capacity market. Mr. Ming argued that units receiving out-of-market payments should not participate in the capacity market due to the price suppression effects on other generators.
- **ISO-NE Pay-for-Performance Testimony, NEPGA 2025:** Mr. Ming submitted expert testimony to the Federal Energy Regulatory Commission on behalf of the New England Power Generators Association (NEPGA) on the pay-for-performance pricing mechanism in the ISO-NE capacity market. Mr. Ming argued that the existing mechanism that allowed fully performing units to be penalized during certain scarcity events was unjust and unreasonable and proposed an alternative framework that rectified this shortcoming.
- **Xcel Colorado Resource Adequacy Study and Testimony, 2025:** Mr. Ming performed a study for Xcel Colorado to calculate the required planning reserve margin (PRM) and resource effective load carrying capability (ELCC) values for the utility. Mr. Ming testified before the Colorado Public Utilities Commission on this study.
- **New Brunswick Power Cost Allocation Study, 2023:** Mr. Ming developed a model to analyze allocation of costs to customer classes using four different cost allocation methodologies: average and peak, average and peak with time-of-use, probability of dispatch, and marginal cost. Mr. Ming testified as an expert before the New Brunswick Energy and Utilities Board, participated in oral hearings, and was cross examined by intervening stakeholders.
- **PURPA Expert Witness Testimony, South Carolina Office of Regulatory Staff, 2023:** Mr. Ming reviewed Public Utilities and Regulatory Policy Act (PURPA) filings submitted by South Carolina’s investor-owned utilities on behalf of the Office of Regulatory Staff. Mr. Ming reviewed for adherence to rate design best practices and application of avoided cost principles for both energy, capacity, and renewable integration costs. Mr. Ming testified before the South Carolina Public Service Commission to provide an overall assessment as well as recommendations for improvement.
- **Market Design Reform Analysis, Public Utility Commission of Texas, 2022-2023:** Mr. Ming led analysis to evaluate the portfolio, reliability, and cost impacts of various market design reform proposals being contemplated in the ERCOT market. E3 published these findings in a report, and Mr. Ming publicly presented these results before the Commissioners at an open meeting and to state legislators.⁴⁵
- **Net Zero New England, Calpine, 2020:** Mr. Ming advised on a comprehensive economy-wide decarbonization analysis with a specific focus on the electricity sector. The analysis focused on the

⁴⁵ <https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=2>

operating challenges at higher penetrations of renewables and the role of firm generation in the New England ISO under a net-zero carbon target.⁴⁶

- **ISONE Capacity Market Design, Confidential Client, 2022:** Mr. Ming, on behalf of a confidential client, presented recommendations to the New England ISO (ISONE) on methods and improvements to better reflect winter reliability risks, particularly due to fuel constraints, in reliability risk modeling used in their capacity market.
- **Capacity Market Design, NYISO, 2022:** Mr. Ming advised the New York ISO (NYISO) on best practices for the adoption of a marginal effective load carrying capability (ELCC) framework within their capacity market construct. In 2022, NYISO became the first ISO to receive FERC approval for the implementation of a marginal ELCC framework. E3 also advised on technical implementation details including best modeling practices to balance both accuracy and simplicity.
- **Capacity Market Design, MISO, 2023:** Mr. Ming was retained by the Midcontinent Independent System Operator (MISO) to provide expert testimony regarding MISO's filing before FERC to implement a "direct loss of load" methodology for use in their capacity market. Mr. Ming also led a team that provided advice on other topics including best practices for assessing local reliability requirements and determining which hours should be utilized in assessing reliability requirements.
- **Capacity Value, Oregon Public Utility Commission, 2020-2022:** Mr. Ming developed a best practices framework for assessing the capacity value of for use in various Commission proceedings. Mr. Ming publicly testified before Commissioners at an open meeting to present results and answer questions.
- **Santee Cooper, the State of South Carolina, 2019-2020:** Mr. Ming managed an engagement with the State of South Carolina to advise on the potential sale of Santee Cooper, a state-owned utility with significant debt due to the abandonment of the V.C. Summer nuclear units 2 & 3. Mr. Ming testified before the South Carolina legislature to present the pros and cons of a potential sale, management arrangement, or reform of the utility.
- **Offshore Wind Reliability Analysis, Confidential Client, 2022:** Mr. Ming led a team to evaluate the reliability contribution of offshore wind in the PJM market for a confidential client. The team utilized detailed renewable output profiles to calculate effective load carrying capability (ELCC) values across a number of different future years and scenarios. The analysis determined that while offshore wind could make meaningful contributions to reliability, there remained a strong role for firm resources to ensure reliability across all conditions.
- **Firm Generation in Microgrids, Mainspring Energy, 2021:** Mr. Ming developed a report for Mainspring Energy evaluating the role of firm generation in local microgrids in California. E3 evaluated several different microgrid configurations including solar + storage, solar + fuel cell, and solar + Mainspring to determine that the lifecycle economics of solar + Mainspring were superior to alternative options, while providing equivalent emission and reliability outcomes.⁴⁷
- **Renewable Reliability Value Analysis, Lincoln Electric System, 2022:** Mr. Ming oversaw a team that calculated renewable capacity values for Lincoln Electric System (LES) within the context of the Southwest Power Pool (SPP) market. The team calculated a forecast of ELCC values for wind, solar, and battery storage, which were provided to LES for use in their 2022 integrated resource plan.⁴⁸
- **Renewable Effective Load Carrying Capability Analysis, Salt River Project, 2022:** Mr. Ming advised on a project to calculate the renewable effective load carrying capability (ELCC) values for wind, solar, and battery storage for Salt River Project (SRP). These values were used in SRP's 2022 integrated resource plan.

⁴⁶ https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf

⁴⁷ <https://www.ethree.com/wp-content/uploads/2021/03/The-Role-of-Firming-Generation-in-Microgrids-E3-and-Mainspring-Energy.pdf>

⁴⁸ <https://www.les.com/sites/default/files/resource-items/irp-report.pdf>

- **Boulder Canyon Dam Pumped Storage Value Analysis, Los Angeles Department of Water and Power, 2019:** Mr. Ming led a team to evaluate the economics of converting Boulder Canyon Dam into a pumped storage facility to provide value integrating the increasing penetration of renewables in the Western interconnection.
- **Wholesale Market Tariffs, Nova Scotia Power, 2020-2021:** Mr. Ming developed testimony to support reforms to existing wholesale market tariffs to ensure they were consistent with best practices in competitive markets across North America.
- **Capacity Market Design, PJM, 2020-2021:** Mr. Ming provided advice to PJM on the incorporation of the effective load carrying capability (ELCC) metric into the PJM capacity market as a method to quantify the contribution of renewable energy and storage resources. Mr. Ming presented publicly the findings of the project at a PJM stakeholder workshop
- **Whitepaper Series, Regulatory Assistance Project, 2022-2023:** E3 worked with RAP to publish a series of whitepapers targeted to Chinese policymakers on topics related to energy and electricity. The whitepapers were published in English and Chinese and covered the topics of time-of-use ratemaking, integrating real-time pricing into rates, the value of long-term contracting, efficient capacity market mechanisms, the role of clean firm generation in a decarbonized electricity system, and the role of demand response and energy efficiency participation in capacity markets.
- **ERCOT Market Design, NRG, 2021:** Mr. Ming developed a whitepaper outlining a proposal to implement a load-serving entity reliability obligation (LSERO) product in the ERCOT market to both improve reliability and make the state less susceptible to scarcity pricing.⁴⁹
- **California Hydrogen and CCS, Confidential Client, 2022:** Mr. Ming led analysis to evaluate the potential role and value of both hydrogen and carbon capture and sequestration (CCS) in California under the incentives of the Inflation Reduction Act.
- **Pathways to Net-Zero Carbon, Omaha Public Power District, 2021:** Mr. Ming led a study on behalf of OPPD to analyze pathways to net-zero carbon. The study found that significant quantities of wind, solar, and battery storage would be components of a least-cost/least-regrets resource plan, supplemented by firm resources for reliability such as natural gas or hydrogen. Mr. Ming led a series of six public stakeholder workshops to provide an opportunity for transparency and public input.
- **Long-Run Resource Adequacy under Deep Decarbonization Pathways for California, 2018-2019:** Mr. Ming authored a report analyzing the resource adequacy requirements of a high-renewable electricity system, consistent with California's long-term decarbonization goals of 80% by 2050. The report demonstrated that despite significant additions of renewable energy and storage, significant quantities of firm capacity were still needed to maintain sufficient reliability.
- **Reliability Value of Demand Response in California, CAISO, 2019-2022:** Mr. Ming led an effort to study the reliability impacts of demand response in the California electricity system using the effective load carrying capability (ELCC) methodology. The study showed that current methods overvalue the reliability value by 25-50%. Mr. Ming presented the findings publicly at multiple stakeholder workshops.
- **Resource Adequacy in the Pacific Northwest, Public Generating Pool, 2018-2019:** Mr. Ming authored a report analyzing the resource adequacy requirements of the Pacific Northwest under various low carbon electricity systems, including 100% carbon-free. This report was presented to multiple stakeholders and utilities in the region and has led to further discussions around resource adequacy coordination and planning.
- **Once-Through Cooling Retirement Analysis, Los Angeles Department of Water and Power, 2017:** Mr. Ming managed a project analyzing the reliability implications of retiring three once-through cooling natural gas power plants in the Los Angeles basin and replacing them with a combination of clean

⁴⁹ https://www.ethree.com/wp-content/uploads/2021/09/LSE-Reliability-Obligation-E3-ERCOT-Whitepaper_2021-09-29.pdf

resources including solar, storage, energy efficiency, and transmission. The results of this study were used to support the decision to retire all three plants and replace them with clean resources.

- **Planning Reserve Margin Study, Nova Scotia Power, 2019:** Mr. Ming led analysis to evaluate the required planning reserve margin (PRM) necessary to achieve a 1-day-in-10 year reliability standard in the province of Nova Scotia. The study also evaluated the contribution of several intermittent and energy-limited resources toward the PRM including solar, wind, energy storage, and demand response. This report was published publicly and formed a basis for Nova Scotia Power's 2020 integrated resource plan.
- **Integrated Resource Planning Support, Confidential Mid-Size Utility, 2018:** Mr. Ming managed a project evaluating the potential replacement of coal resources with renewable, energy storage, and natural gas resources in order to achieve decarbonization targets for a confidential mid-size utility.
- **Net Energy Metering Analysis, Various Clients, 2014-2017:** Mr. Ming performed analysis and published reports for various state utility commissions (California, Nevada, New York, South Carolina) evaluating the costs and benefits of net energy metering policies.
- **Heat Pump Analysis, New York State Energy and Research Development Authority, 2017:** Mr. Ming performed analysis on the costs and benefits of electric heat pumps to replace oil and natural gas heating in New York state as well as increase the efficiency of existing air conditioners. This work was published in a public report that led to the development of policies to incentivize heat pump adoption.
- **Resource Adequacy Program Design, Calpine, 2016:** Mr. Ming performed analysis on behalf of Calpine and presented to the California Public Utilities Commission (CPUC) to recommend the use of the effective load carrying capability (ELCC) metric in the Resource Adequacy (RA) program for wind and solar resources. The CPUC ultimately adopted this recommendation along with several market design features proposed by E3.
- **California Avoided Cost Calculator, California Public Utilities Commission, 2016-2018:** Mr. Ming led an update of the avoided cost forecast used to conduct cost and benefit analysis for demand-side programs in California, including energy efficiency, demand response, and distributed generation.
- **Title 24 Building Standard Development, California Energy Commission, 2016-2017:** Mr. Ming developed a forecast of future energy costs for the State of California used to establish building energy efficiency standards under Title 24.
- **Resource Value of Solar, Oregon Public Utilities Commission, 2016:** Mr. Ming contributed to expert testimony on the resource value of solar before the Oregon Public Utilities Commission.
- **Policy and Technology Scenario Analysis, Confidential Large U.S. Utility, 2015:** Mr. Ming modeled policy and technology-change scenarios for a large U.S. utility as part of their strategy planning process.

GENERAL ELECTRIC

Renewable Energy Development Program (REDP) Intern

Schenectady, New York

Summer 2012

CITIGROUP

Commodities Summer Analyst

Houston, Texas

Summer 2011

OGE ENERGY CORP (Enogex)

Capacity Management Intern

Oklahoma City, Oklahoma

Summer 2010

MAP ROYALTY

Engineering Intern

Oklahoma City, Oklahoma

Summer 2009

Education

Stanford University

M.S., Management Science and Engineering (Energy and Environment)

Stanford, California

2013

Stanford University

B.S., Civil and Environmental Engineering (Atmosphere and Energy)

Minor in Economics

Stanford, California

2012