UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Industrial Energy Consumers of America; American Forest & Paper Association; R Street Institute; Glass Packaging Institute; Public Citizen; PJM Industrial Customer Coalition; Coalition of MISO Transmission Customers; Association of Businesses Advocating for Tariff Equity; Carolina Utility Customers Association, Inc.; Pennsylvania Energy Consumer Alliance; Resale Power Group of Iowa; Wisconsin Industrial Energy Group; Multiple Intervenors (NY); Arkansas Electric Energy Consumers, Inc.; Public Power Association of New Jersey; Oklahoma Industrial Energy Consumers; Large Energy Group of Iowa; Industrial Energy Consumers of Pennsylvania; Maryland Office of People's Counsel; Pennsylvania Office of Consumer Advocate; Consumer Advocate Division of the Public Service Commission of West Virginia; and Missouri Industrial Energy Consumers

v.

Avista Corporation; Idaho Power Company; MATL LLP; NorthWestern Corporation; PacifiCorp; Portland General Electric Company; Puget Sound Energy, Inc.; Duke Energy Florida, LLC; Florida Power & Light Company; Tampa Electric Company; Dominion Energy South Carolina, Inc.; Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.; Louisville Gas and Electric Company and Kentucky Utilities Company; Southern Company Services Inc., as agent for Alabama Power Company, Georgia Power Company, Georgia Power Company and Mississippi Power Company; Arizona Public Service Company; Black Hills Power, Inc.; Black Hills Colorado Electric Utility Company, LP; Cheyenne Light, Fuel & Power Company; El Paso Electric Company, NV Energy, Inc.; Public Service Company of Colorado; Public Service Company of New Mexico; Tucson Electric Power Company; UNS Electric, Inc.; California Independent System Operator, Inc.; Southwest Power Pool, Inc.; PJM Interconnection, L.L.C.; Midcontinent Independent System Operator Inc.; New York Independent System Operator, Inc.; and Independent System Operator of New England Inc.

Docket No. EL25-44-000

COMMENTS OF RMI

RMI[1] submits these comments in response to the January 7, 2025 notice[2] inviting comments to the complaint filed on December 19, 2024 by the above-captioned Complainants.[3] In our comments, we affirm the issues highlighted by Complainants and illustrate how spending on local transmission has risen in recent years, in part driven by what we call a "regulatory gap."

---

[1] RMI is a 501(c)3 not-for-profit organization whose mission is to transform the global energy system to secure a clean, prosperous, zero-carbon future for all.

[2] Federal Energy Regulatory Commission (FERC)**,** *Notice of Extension of Time,* Docket No. EL25-44-000 (Jan. 7, 2025).

[3] FERC, *Complaint of Consumers for Independent Regional Transmission Planning for All FERC-Jurisdictional Transmission Facilities at 100 kV and Above*, Docket No. EL25-44-000 (Dec. 19, 2024).

We then leverage recommendations from our new report, *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight*, to explain how the Commission can close the regulatory gap to make transmission spend in the US more affordable and efficient. These recommendations build on the Complainants' request and include requiring "regional-first planning" (mandatory right-sizing consideration for all local projects), establishing an independent transmission monitoring authority, reforming the formula ratemaking process, standardizing local project definitions and tracking, and strengthening state input and influence at the regional planning level.

Introduction

RMI appreciates the opportunity to provide comments on this timely complaint. We affirm the issues highlighted by Complainants—notably, that spending on transmission projects that are subject to less regulatory scrutiny has accelerated in recent years. This trend has resulted in unjust and unreasonable rates for consumers in that they are being charged for significant spending on transmission that is lacking sufficient oversight at the federal, regional, and state levels. We documented this trend and the implications for consumers in our recently released report, *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight* ("*Mind the Regulatory Gap*"), which we also filed with the Commission in Docket No. AD22-8-000 as an informational filing on December 12, 2024.[4] This report draws on evidence from Docket No. AD22-8-000 as well as interviews conducted with a diverse range of stakeholders from across 18 states, including state regulatory commissioners and staff, state consumer advocates, academics, and advocates.

[4] Claire Wayner, Kaja Rebane, and Chaz Teplin, *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight*, RMI, 2024, https://rmi.org/insight/mind-the-regulatory-gap

In our comments below, we draw on insights from our *Mind the Regulatory Gap* report to both affirm the assertions made by the Complainants and lay out a framework for how the Commission can implement a robust regulatory framework that would ensure sufficient oversight of *all* types of transmission projects. Given that spending on transmission is only increasing and has hit record-high levels in recent years,[5] yet at the same time the US has hit a record *low* of high-voltage lines installed,[6] we believe it is urgent that the Commission act in a timely manner on this complaint to rectify the uneven landscape that currently exists with respect to transmission project oversight.

A. Local Transmission Spending Has Been Increasing in Recent Years

As we illustrate in our *Mind the Regulatory Gap* report, and as the Complainants assert, spending on local projects has increased significantly in recent years. In our report, we synthesize multiple data points provided by various commenters in Docket AD22-8-000 and at the FERC technical conference on this topic in October 2022.[7] Regionally, these include a shift in spending on local (Supplemental) projects in the PJM Interconnection from 9% of total spend from 2005-2013 to 73% of total spend from 2014-2021.[8] In MISO, local (Other) projects have increased from 54% of total spend in 2017 to 78% in 2022.[9] In CAISO, 63% of projects from

[5] According to the US Energy Information Administration (EIA), "spending on electric transmission systems nearly tripled from 2003 to 2023, increasing to $27.7 billion." See "Grid infrastructure investments drive increase in utility spending over last two decades," US EIA, November 18, 2024, https://www.eia.gov/todayinenergy/detail.php?id=63724

[6] According to a report last year from Grid Strategies and Americans for a Clean Energy Grid (ACEG), "only 55 new miles of high-voltage transmission were constructed in 2023." See Nathan Shreve, Zachary Zimmerman, and Rob Gramlich, *Fewer New Miles: The US Transmission Grid in the 2020s*, Grid Strategies with support from ACEG, July 2024, https://cleanenergygrid.org/wp-content/uploads/2024/07/GS_ACEG-Fewer-New-Miles-Report-July-2024.pdf

[7] FERC, "Technical Conference on Transmission Planning and Cost Management," Docket No. AD22-8-000 (October 6, 2022), https://www.ferc.gov/news-events/events/technical-conference-transmission-planning-and-cost-management-10062022

[8] Claire Wayner, "Increased Spending on Transmission in PJM — Is It the Right Type of Line?," RMI, March 20, 2023, https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/

[9] FERC, "Pre-Technical Conference Statement of Jennifer Easler, Consumer Advocate, Iowa Office of Consumer Advocate — Division of Iowa Department of Justice, Panel 2: Local Transmission Facility Cost Management

2018 to 2022 were local (self-approved).[10] In ISO-NE, spending on local (asset condition) projects increased eightfold from 2016 to 2023.[11]

Nationally, we have also seen evidence of the increased shift in spending to local projects. In the Commission's *State of the Markets 2021* report, since 2014, the percentage of spending on transmission projects with voltages of 230 kilovolts (kV) or higher has been steadily decreasing, from 72% in 2014 to 34% in 2021.[12] This is indicative of the shift in spending to local projects, as local projects are frequently built at lower voltages. In an analysis released in 2023, the Brattle Group found that 90% of recent transmission spending has been on lower-voltage reliability projects, with 50% of all spending going to local projects.[13] And, in the Commission's Notice of Proposed Rulemaking (NOPR), "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," the Commission directly acknowledged how the "vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities."[14]

The increase in spending on local projects in recent years has occurred alongside an increase in *overall* transmission spending, which has driven costs up for ratepayers without clear benefits. The US Energy Information Administration (EIA) found in 2024 that spending on the

---

Practices," Docket No. AD22-8-000 (October 4, 2022), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221004-5150&optimized=false

[10] FERC, "Summary Statement of Simon Hurd on Behalf of the California Public Utilities Commission," Docket No. AD22-8-000 (September 16, 2022), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220916-5185&optimized=false

[11] FERC, "Comments of Massachusetts Municipal Wholesale Electric Company, New Hampshire Electric Cooperative, Inc., Connecticut Municipal Electric Energy Cooperative, and Vermont Public Power Supply Authority," Docket No. AD22-8-000 (March 23, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20230323-5173&optimized=false

[12] *State of the Markets 2021*, FERC Office of Energy Policy and Innovation Division of Energy Markets Assessments, April 21, 2022, https://www.ferc.gov/media/report-2021-state-markets

[13] *Annual U.S. Transmission Investments, 1996-2023*, Brattle Group, 2023, https://www.brattle.com/wp-content/uploads/2023/07/Annual-US-Transmission-Investments-1996–2023.pdf

[14] Federal Energy Regulatory Commission, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," Docket No. RM21-17-000 (April 21, 2022), p. 35 at 40.

electric transmission system has nearly tripled from 2003 to 2023.[15] In our *Mind the Regulatory Gap* report, we document how transmission and distribution expenses comprise an increasing portion of residential bills nationwide, from 10% in 2005 to 24% in 2020.[16]

While transmission spending has been increasing, the US has seen a record low installation of high-voltage transmission projects. An analysis by Grid Strategies published in 2024 found that while transmission spending hit an all-time high in 2023, the US built only "20% as much new transmission [mileage-wise] in the 2020s as it did in the first half of the 2010s." Only 55 miles of new high-voltage transmission were added in 2023, compared to a record 4,000 miles in 2013.[17]

Based on this data, it is clear that while transmission spending is on the rise in the US, investment is going toward lower-voltage, local projects and not toward high-voltage, regional projects. This results in spending that raises ratepayers' bills without the inherent efficiencies that result from regional and interregional transmission planning that the Commission itself has acknowledged.[18]

B. A Regulatory Gap is Driving the Increased Spending on Local Transmission

One of the principal drivers of this increased local transmission spending that we document in our report is what we refer to as a "regulatory gap," or an opportunity for local projects to avoid sufficient oversight from federal, regional, or state entities.

---

15 "Grid infrastructure investments drive increase in utility spending over last two decades," US EIA, November 18, 2024, https://www.eia.gov/todayinenergy/detail.php?id=63724

16 Claire Wayner et al., *Mind the Regulatory Gap*, p. 13

17 Shreve et al., *Fewer New Miles*, Grid Strategies, July 2024

18 Docket No. RM99-2-000, "Regional Transmission Organizations," p. 486, Federal Energy Regulatory Commission, December 20, 1999, https://www.ferc.gov/sites/default/files/2020-06/RM99-2-000.pdf; and as cited in Docket No. AD22-8-000, "Pre-Conference Comments of Joshua C. Macey, Assistant Professor at the University of Chicago Law School," p. 4, October 3, 2022, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221003-5020&optimized=false.

On the federal level, most transmission spending today receives rate approval under the Commission's formula ratemaking option. As we explain more in our report, formula rates do not allow for the project-level scrutiny necessary to ensure that local projects are prudent—the Commission instead assumes prudency for all expenditures presented as part of formula rate proceedings, with the burden placed on third parties to prove otherwise. This allows local projects to receive rate approval by the Commission with limited, if any, review. While there are instances where the Commission has found local projects to suffer from data inaccuracies, in most cases, state regulatory bodies and consumer advocates do not have sufficient data access or resources (staff, financial, etc.) to intervene meaningfully in each formula rate case. They often find themselves at an information asymmetry, in which there is not enough information in the formula rate case to scrutinize utility investments at the project level. Moreover, as we explain later in our comments, **the best level to address local planning is on a streamlined regional basis rather than on a piecemeal project-by-project basis in rate cases**. This position was reiterated by several of our interviewees in preparing our *Mind the Regulatory Gap* report.

On the state level, many states legislatively exempt certain types of local projects from receiving certificates of public convenience and necessity (CPCNs), including rebuilds of existing transmission infrastructure or projects occurring below a certain voltage threshold.[19] This results in many state public utility commissions not hearing about local projects until they are already in rates approved by the Commission.

While one of the recommendations in our report included states expanding their CPCN requirements to incorporate more local projects, we note that many of our interviewees, including state regulatory commissioners and staff, explicitly mentioned how **relying solely on**

[19] See "Exhibit 5: State-Level CPCN Review Authority by Voltage" on p. 23 of RMI's *Mind the Regulatory Gap* report.

CPCNs for local transmission oversight is insufficient to close the regulatory gap. In CPCN proceedings, commissioners and staff remarked how they are often unable to have an understanding on the "bigger picture" landscape within which local projects reside, as CPCN proceedings are each focused on a single project. Given the limited view of each proceeding, commissioners and staff are unable to, for instance, assess the potential for local projects to be right-sized to also address regional needs. Local projects can also span multiple state boundaries, resulting in an uneven landscape for state regulators.

Our interviewees consistently reiterated how the regulatory gap **must be closed at the regional level** through enhanced regional planning and right-sizing. This does not preclude the CPCN as an important tool for state regulators to weigh in and rule on the need for and prudence of local projects. Regional planners are *not* the same as regulators, and state regulators must still retain the important function of issuing CPCNs for local projects. However, this must be accompanied by revisions to regional planning processes, which only the Commission can undertake.

The current review of local projects on the regional level is minimal. Most regional planners today perform a basic "do-no-harm analysis" to ensure that local projects do not threaten grid reliability before allowing local projects to be built. This analysis does not scrutinize the prudence or need of a local project, nor in many cases does it look at the potential for local projects to be "right-sized" to also address regional needs. While the Commission in Order No. 1920 included requirements for enhancing transparency of local projects and considering right-sizing opportunities as part of long-term planning, these provisions still fall short of creating a robust landscape for local project review at the regional level. For instance, the Commission exempted asset management projects from the transparency requirements, even though these projects often constitute the majority of local spending. The Commission also applied the right-sizing consideration requirement to only long-term planning and not *all* timescales of regional planning. **These Order No. 1920 provisions, while important steps in the right direction, are not enough to ensure that local planning is maximally synergistic with regional planning.**

C. Action Must Be Taken by the Commission to Close the Regulatory Gap

As we show in our report, actions at the federal, regional, and state levels are needed to close the regulatory gap and ensure that consumers' rates are just and reasonable. Failure to close the regulatory gap will likely result in continued upward spending by utilities on local transmission projects, at the expense of ratepayers and without the full benefits that regional projects provide.[20]

We believe that the Complainants lay out a series of reforms that will begin to meaningfully close the regulatory gap. First, we agree with the Complainants' request that all transmission projects 100 kV or higher, including those "reaching the end of operational life," be planned at the regional or interregional level and that such regional planning be "conducted by an independent transmission system planner."[21] We believe that this voltage threshold would align well with the definition of the Bulk Electric System[22] and that the Complainants include sufficient exemptions to allow for utility and operational flexibility (distribution facilities, emergency rebuilds/*force majeure* circumstances, and merchant transmission[23]). As we noted earlier, regional and interregional planning has significant potential for enhanced efficiencies compared to local planning, so streamlining as much transmission investment through those

[20] For an illustration of the multiple benefits regional transmission can provide, see Tyler Farrell, Celia Tandon, Beverly Bendix, and Chaz Teplin, *High Voltage, High Reward Transmission*, RMI, 2025, https://rmi.org/insight/high-voltage-high-reward-transmission/

[21] Complaint at p. 43.
[22] Complaint at p. 209.
[23] Complaint at p. 239.

pathways is critical. We also agree with the Complainants' definition of an Independent Transmission Planner for each Order No. 1000 region[24] and affirm that independence is critical for ensuring just and reasonable rates result from regional planning. With that said, we believe that the Commission must take additional action to continue to close the regulatory gap.

a. **Require regional-first planning.**

First, the Complainants' proposed relief still leaves some of the regulatory gap open. For instance, establishing a voltage threshold could result in a shift in spending to projects that fall below 100 kV. To ensure that this outcome does not happen, we recommend that the Commission **require right-sizing consideration for all local projects at all timescales of planning** (not just long-term planning, as was established in Order No. 1920). This requirement must apply to all types of local projects, including asset management projects, to ensure maximum effectiveness. Given the increasing aging of the grid and the potential synergies between replacing aging assets and addressing near-term demands of the grid, we believe that the Commission's exemption of asset management projects in Order No. 890 is worthy of revisiting, to the extent that asset management projects can be designed to also meet regional needs. The recent passage of Resolution EC-3 at the February 2025 National Association of Regulatory Utility Commissioners (NARUC), which calls on the Commission to "act swiftly to put in place effective and robust transmission cost management and oversight processes for 'end of life' or 'asset condition' transmission projects,"[25] further underscores the need for the Commission to revisit this exemption.

---

[24] Complaint at p. 232.

[25] "EC-3 ERE-3 Resolution on Electricity Consumers' Need for Effective Oversight of Costs for Replacing Aging or Obsolete Transmission Infrastructure," sponsored by Commissioner Patrick Scully, passed by the Committee on Energy Resources and the Environment on February 24, 2025, and the Committee on Electricity on February 25, 2025, adopted by the NARUC Board of Directors on February 26, 2025. https://pubs.naruc.org/pub/A37E3860-

In our report, we refer to this mandatory right-sizing requirement as *regional-first planning*, an approach to planning that requires regional projects be planned and prioritized ahead of local projects. We provide more detail about regional-first planning in our report.[26] At a high level, the process proceeds as such: (1) utilities submit local needs, (2) the regional planning entity identifies the regional needs in addition to local needs, (3) the regional planning entity identifies the best solutions to address both local and regional needs in consultation with utilities and other stakeholders, and (4) utilities have the option to submit additional local projects to address local needs that remain unaddressed by those solutions identified by the regional planning entity in the previous stage of planning. Notably, any additional local projects submitted by utilities would need to be carefully scrutinized by state and federal regulators to ensure that such spending is necessary. If the Commission accepts the 100 kV threshold proposed by the Complainants, then the last step in our regional-first planning process flow would apply only to projects below 100 kV.

b. **Establish an independent transmission monitoring authority.**

We also recommend that the Commission **establish an independent transmission monitoring authority**, either at the regional or federal level, to ensure that adequate scrutiny of transmission spending is occurring. Such an authority could, for instance, annually summarize transmission spending trends across planning regions and identify areas where transmission spending may continue to be inefficient (e.g., if one region sees spending shift to be below 100 kV). This authority has been referred to by various terms in past Commission proceedings, including an Independent Transmission Monitor (ITM).[27] We believe that the record in these

---

ECFF-DBA3-13A7-BA3B120910C2?_gl=1*msfch9*_ga*MTk3NzYzODUzLjE3NDAwNzE3OTk.*_ga_QLH1N3Q1NF*MTc0MDY4OTA5MS41LjEuMTc0MDY4OTU3NC4wLjAuMA

[26] Claire Wayner et al., *Mind the Regulatory Gap*, p. 35.
[27] See FERC Docket No. AD22-8-000.

proceedings has squarely established the Commission's legal authority to create such a monitoring authority, either sitting at the federal (e.g., a new office within the Commission) or regional (e.g., requiring each regional planning entity to establish a monitoring authority) level. Several interviewees in our report remarked how important the independent monitoring function is to provide them (including state regulators and consumer advocates) with sufficient data and information to understand transmission spending trends. In addition to producing annual summaries of transmission spending trends, such a monitoring authority could also provide state regulators and consumer advocates with information on specific transmission projects on an as-requested basis.

c. **Reform the formula ratemaking process to ensure adequate scrutiny and appropriate incentives.**

We also recommend that the Commission reform its formula ratemaking process to ensure that local projects are receiving adequate scrutiny. For projects that are not regionally planned and/or reviewed by a state regulatory entity (e.g., issued a CPCN by a state PUC), we recommend that the Commission **remove the presumption of prudence** for these projects and require utilities to submit documentation of the need and prudence of such project investments. This will ensure that projects that have not been reviewed by state regulators and/or regional planning entities do not "slip through the cracks" in the formula ratemaking process. We encourage the Commission to survey each state regulatory entity on a regular basis to best understand each state's transmission project review requirements, including CPCN requirements, and ensure that the Commission presumes prudence only for those projects that receive adequate regulatory scrutiny through other venues.

The Commission could also consider other amendments to the ratemaking process to further incentivize regional investment that we document in our report, such as **lowering the**

allowed return on equity (ROE) for local projects. Local projects often do not face the same level of investment risk that regional projects may face (e.g., smaller in scale, built on an existing right-of-way, lower-voltage, etc.). As a result, local projects may not require the same ROE that regional or interregional transmission investments may require. The Commission could also **remove the RTO membership ROE adder for local projects** that do not have a right-sizing analysis performed, since these projects are not meaningfully integrated into plans at the regional level as we explained earlier in our comments (i.e., only a do-no-harm analysis is performed in most cases). More broadly, the Commission could investigate opportunities to recalculate utility ROEs in general. Recent research, including from RMI, has shown how utility ROEs continue to be overinflated relative to market performance.[28] Finally, the Commission could **lower the evidentiary standard for parties interested in raising challenges as part of formula rate cases**. This would enable greater public participation by interested and relevant entities who may otherwise struggle to participate. We encourage the Commission to seek input from state regulators and consumer advocates on this point in particular, including on the current evidentiary standard and how it could be made less onerous to intervene.

d. Standardize local project definitions and tracking.

As we describe in our report, each Order No. 1000 planning region uses different terminology to refer to local projects and types of local projects. In addition, each utility within each planning region may use its own terminology to refer to drivers and criteria associated with their local projects. This can result in a challenging landscape for state regulators and consumer

[28] "...evidence suggests that allowed utility ROEs have become increasingly generous over the past few decades. In fact, since the 1990s they have fallen less than prevailing interest rates and costs of capital. Evidence also clearly suggests that ROEs are higher than the return investors require." For more information and for recommendations on how ROE can be calculated in a more accurate and equitable manner, see Joe Daniel et al., *Rebalancing "Return on Equity" to Accelerate an Affordable Clean Energy Future*, RMI, 2025, https://rmi.org/rebalancing-return-on-equity-to-accelerate-an-affordable-clean-energy-future/

advocates, whose jurisdiction may span multiple planning regions. We recommend that the Commission **require each region to standardize its terminology for local project drivers and criteria** used by utilities across its regional footprint. Such standardized terminology should be used in all local project presentations and documentation at the regional planning level (e.g., the series of three meetings required by the Commission under Order No. 1920). The Commission should then publish and regularly update a list of terminology utilized by each regional planning entity. We believe that this recommendation still allows for regional flexibility (e.g., each region could utilize its own set of terminology) while creating a landscape that is easier for state regulators, consumer advocates, and other stakeholders to navigate.

In addition, the Commission should **require regular data sharing and publication of transmission spending**, on at least an annual basis, for local, regional, and interregional projects. Data should be shared at a project level and published on both the regional planning entity website *and* the Commission's website (with the latter being an aggregate of data from across all regional planning entities, such as a schedule under Form 1). Currently, data transparency and accessibility standards vary *widely* across Order No. 1000 planning regions. Moreover, Commission-shared data (e.g., Schedules 422 and 424 of Form 1) often has significant gaps (e.g., most cells are left blank), making such data unusable for understanding project-level investments and overall spending trends.

The Commission could update its requirements for Form 1 data sharing to **require that utilities leave no cells blank** unless such information is deemed CEII by the Commission (in which case the Commission should note in the dataset where such data has been redacted. The Commission could also update Schedule 422 to include the following fields to better equip consumer advocates and regulators with knowledge of transmission spending trends: (1) distinguish among original project proposal date (i.e., date introduced at regional planner and/or state regulatory entity), original proposed in-service date, and date energized (to get a sense of any construction delays), (2) distinguish between original proposed capex budget and final capex spend (to allow a sense of any cost overruns), (3) type of transmission infrastructure investment (e.g., line, transformer, substation), (4) whether the investment was open to a competitive solicitation, (5) whether the investment was subject to a cost-benefit analysis (and, if so, additional details on the analysis's findings), (6) category of project using its regional planning entity's terminology (e.g., if in PJM, Baseline, Supplemental, Network Upgrade, etc.), (7) cost allocation details at the transmission owner zonal level, and (8) whether the investment is a new build, reconductoring, or rebuild of an existing line. Such additional data fields should not be significantly burdensome to utilities to submit data on. For instance, in PJM, most of this data is already available in PJM's online TC Planner tool.[29]

e. **Strengthen state input and influence at the regional level.**

A final recommendation from our report we would like to highlight is the importance of strong roles for state regulators and consumer advocates within the regional planning entity. Ensuring the regional planning entity's independence is just the first step toward best-practice regional planning. In many regions, states have expressed concern at their lack of consultation as part of and integration into regional planning processes. Transmission plans are often finalized and approved by RTO Boards, for instance, without final consultation and approval by state entities. We recommend that the Commission **consider establishing a pathway for state regulators to submit regular input to the Commission on issues pertaining to regional planning** under a mechanism that is less burdensome than a Section 206 filing under the Federal Power Act. The Commission hearing state input regularly (e.g., annually) could enable the Commission to better understand what amendments to regional planning processes need to

[29] "Transmission Cost Planner," PJM, tcplanner.pjm.com

happen to ensure best outcomes are occurring. Such input could happen through written comments on an annual or *ad hoc* basis or via an established forum, such as the Federal-State Current Issues Collaborative.[30] The Commission could also **establish regional entities for consumer advocates**, similar to the Consumer Advocates of the PJM States (CAPS) model in PJM, which has provided demonstrable benefits to state consumer advocates in the PJM region to better engage at the RTO.[31]

Conclusion

In conclusion, we affirm the concerns expressed by the Complainants that local transmission spending has accelerated with little oversight at the federal, regional, and state levels. As we document in our *Mind the Regulatory Gap* report, such spending is in part driven by a regulatory gap, which the Commission has an important role in closing. Action must be taken at the federal, regional, *and* state levels to fully address the regulatory gap.

To that end, we affirm the requests for relief that the Complainants identify, including requiring all projects 100 kV and higher, including those at the end of their operational life and with limited exceptions, to be planned at the regional level by an independent transmission planner. In addition, we include in these comments five additional recommended actions that the Commission can take to further close the gap. This includes (1) establishing a regional-first planning regime in all Order No. 1000 planning regions by requiring right-sizing consideration for all timescales of planning, (2) establishing an independent transmission monitoring authority at the regional or federal level, (3) reform the formula ratemaking process to ensure adequate scrutiny and appropriate incentives as well as lowering the burden of intervention for relevant

[30] FERC, "Federal-State Current Issues Collaborative," Docket No. AD24-7-000, https://www.ferc.gov/federal-state-current-issues-collaborative

[31] Multiple interviewees in our report writing process remarked on the positive impacts of the CAPS model and how it should be scaled to all Order No. 1000 planning regions.

stakeholders, (4) standardize local project definitions and tracking, including public data sharing, and (5) strengthen state regulator and consumer advocate input and influence at the regional level.

For the foregoing reasons, RMI respectfully requests that the Commission consider these comments in deciding how to respond to this complaint and related dockets (Docket No. AD22-8). Unless the Commission takes rapid action, consumers will continue to bear the burden of increasing transmission spending without adequate oversight by regulatory entities, subjecting them to unjust and unreasonable rates.

Respectfully submitted,

/s/ Claire Wayner

Claire Wayner
Senior Associate
RMI
2490 Junction Pl, Suite #200
Boulder, CO 80301
cwayner@rmi.org