UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Management	)))))	Docket No. AD22-8

Comment of the Harvard Electricity Law Initiative[1]

Utility transmission investment decisions hinge on the Commission rates and rules. Over the past several years, utilities' capital expenditures on local facilities have spiked, in part because Commission regulation does not hold utilities accountable for their decisions or expenditures. Utilities spend without prior approval from any regulator and without consequences for delays, cost overruns, or imprudence. Costs flow through to customer bills without meaningful scrutiny and often without disclosure until they appear in a formula rate update.

Customers have little recourse. The information asymmetry between a utility and its customers prevents meaningful participation in planning processes and rate proceedings. Rate case shortcuts deny consumers the protections of section 205 and make a section 206 challenge all but impossible. Customers, stakeholders, and state regulators have no hope of successfully challenging utility-planned projects, opposing prudence, or building a long-term record about the utility's performance. As Paul Joskow summarized, "for all intents and purposes the [Commission's transmission] regulatory process is a model of cost pass-through regulation with little scrutiny of costs."[2] The only risk utilities face is that a Commission audit

[1] The Harvard Electricity Law Initiative is an independent organization based at Harvard Law School's Environmental & Energy Law Program. These comments do not represent the views of Harvard University or Harvard Law School.
[2] Paul L. Joskow, MIT Center for Energy and Environmental Policy Research, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, p. 13 (Mar. 2019).

might discover a costly accounting mistake or potential fraud. But audits are infrequent, and they do not investigate the efficiency or prudence of utilities' investments or consider whether utility decisions unduly discriminate against utility competitors or result in unjust and unreasonable rates for customers.

The Commission is a utility regulator that has ample authority to better protect consumers. Our responses to the Commission's post-technical conference questions suggest two overarching goals for reforms: 1) expand utility disclosures and 2) enable transmission customers and stakeholders to viably challenge rates. The Commission can achieve the first goal by revisiting Order No. 890, amending formula rate protocols, and/or empowering ratepayer transmission monitors (RTMs). But additional disclosures will be worthless without mechanisms for holding utilities accountable. Currently, cost recovery is automatic, regardless of need, project alternatives, or cost overruns. We suggest that the Commission issue a policy statement describing a new approach for reviewing utility transmission expenditures. We outline a policy that would respect state oversight, involve state regulators in cost recovery decisions, and give consumers a chance of successfully challenging utility rates.

We also urge the Commission to ensure that formula rates are not a mechanism for evading oversight. Transmission customers paying formula rates ought to be afforded the same protections as consumers paying stated rates. To restore a meaningful role for section 205 in annual formula rate proceedings, the Commission could require utilities earning formula rates to disclose information sufficient to make a *prima facie* case that the cost recovery it seeks would result in just and reasonable rates if it sought recovery through stated rates. Imposing this transparency standard on utilities would not change the mechanics of formula rates. Utilities would still recover costs included in annual update filings without prior Commission review. Disclosure would facilitate ratepayer challenges, and the *prima facie* standard provides the Commission with a means for evaluating whether disclosure is sufficient. If a utility fails to meet that standard, it can still recover its costs but it must remedy the disclosure deficiency.

Transparency is needed to facilitate meaningful customer review and provide the Commission with a basis for presuming that the utility's transmission rates are just and reasonable. In other contexts, when the Commission relies on presumptions of justness and reasonableness, it does so based on factual evidence or economic principles.[3] The Commission currently presumes that allowing utilities to recover every dollar they seek from ratepayers results in just and reasonable rates. Presuming a monopolist's cost-based rates are just and reasonable violates basic economic assumptions of utility regulation. While the Commission has broad discretion under section 205, it may not "simply choose not to regulate rates."[4]

With the reforms we have outlined above, the Commission would continue to rely on customers and stakeholders to bring transmission rate and planning issues before the Commission rather than proactively reviewing these matters under section 205. Alternatively, the Commission could take a more drastic approach by ending automatic pass-through of utility-planned capital expenses and instead reviewing a limited set of those expenses for prudence. This restoration of direct oversight would prevent recovery of self-planned capital expenses through existing formula rate processes. Rather than imposing this reform, we suggest that the

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[3] *See, e.g.,* Morgan Stanley Capital Group v. Public Util. Dist. No. 1 of Snohomish County, 554 U.S. 527, 530 (2008) (summarizing that the Commission presumes freely negotiated contracts result in just and reasonable rates); Montana Consumer Counsel v. FERC, 659 F.3d 910, 914–17 (9th Cir. 2011) (explaining that the Commission presumes market-based rates are just and reasonable only when the seller demonstrates it does not have market power); Order No. 697-A, 123 FERC ¶ 61,055 at P 111 (adopting a rebuttable presumption that RTO/ISO market monitoring is sufficient to address market power concerns and ensures just and reasonable rates).

[4] Texaco v. FPC, 417 U.S. 380, 394 (1974) (quoting Texaco v. FPC, 474 F.2d 416, 422 (D.C. Cir. 1972) and noting the FPC does not challenge this aspect of the D.C. Circuit's judgment).

Commission provide utilities with a choice: either adopt a RTM or prove prudence and lose automatic pass-through of self-planned capital expenses.

A dormant regulatory concept supports limiting the scope of these reforms to self-planned projects, including asset replacements, local expansions, and non-RTO regional investments. Distinguishing between investments based on the planning entity is consistent with the Commission's "independent entity variation" policy, which recognizes that an RTO is "less likely to act in an unduly discriminatory manner than a transmission provider that is a market participant."[5] As applied to transmission rates, the Commission could find that greater oversight is warranted for utility-planned projects than projects approved by an independent RTO board and vetted through a Commission-approved stakeholder process.

Enhancing oversight of local planning and rates will partially remedy the perverse incentives biasing utilities in favor of local projects. As a utility regulator, FERC must scrutinize "the nature and adequacy of the incentives and pressures that influence private management in making the critical economic decisions."[6] The Commission is in the process of doing so through multiple ongoing proceedings.[7] In this proceeding, the Commission can partially address the unjustifiable profit gap between local and regional investments. A recent case study of transmission investment in PJM shows that utilities earn 16 to 24 percent higher returns per

[5] Order No. 2003, 104 FERC ¶ 61,103 at P 827 (2003).

[6] Alfred Kahn, THE ECONOMICS OF REGULATION, VOL II at 47 (1970).

[7] Relevant open dockets include: RM21-17 (long-term planning); RM22-14 (generator interconnection reforms); RM22-10 (extreme weather reliability planning standard); RM22-16 (vulnerability assessments); RM20-10 (incentives); RM21-3 (cybersecurity incentives); RM22-7 (permitting); AD22-5 (dynamic line ratings); and AD23-3 (interregional transfer capability). The Commission has finalized Order No. 881, Managing Transmission Line Ratings, 177 FERC ¶ 61,179 (2021). Meanwhile, the U.S. Department of Energy is also in the midst of numerous transmission financing and planning efforts. See U.S. Department of Energy, Notice of Intent, Building a Better Grid Initiative To Upgrade and Expand the Nation's Electric Transmission Grid To Support Resilience, Reliability, and Decarbonization, 87 Fed. Reg. 2769 (Jan. 19, 2022).

dollar invested in local projects as compared to regional projects.[8] This disparity is driven by the shorter timelines of local project development and lower cancellation rates. Our comment focuses on the regulatory construct that insulates local development from risks by eliminating the scrutiny ordinarily applied to utility decisions and expenditures. By de-risking local transmission, the Commission has created an attractive investment opportunity that funnels undue profits to utility shareholders. Our proposals in this comment attempt to arm customers with information that they can use to defend themselves against exploitation.

There is a more straightforward remedy to this local bias. The Commission could set lower ROEs for local projects or for in-kind replacements. A lower ROE would be commensurate with the lower risk profile of these projects and would therefore appropriately compensate utilities. Recent research shows that ROEs approved by state regulators and the Commission are providing much greater risk-adjusted returns on equity than utilities historically received.[9] Yet, as their ROEs are increasing, utilities are reducing their risks by focusing jurisdictional investments on local projects. The rewards provided by regulators are out of sync with utilities' real-world risks.

Before proceeding to our responses to the Commission's questions, we acknowledge that the Commission may have limited resources to expend on transmission oversight. Our proposed reforms account for this constraint. If the Commission does nothing else, it should demand that utilities provide data that would facilitate a form of yardstick competition. The Commission already has

[8] Claire Wayner, RMI, "Increased Spending on Transmission in PJM – Is It the Right Type of Line?" (Mar. 20, 2023).

[9] Albert Lin, Pearl Street Station Finance Lab, "Electricity Bills Too High? Then, Get The ROE in Line," (Aug. 2022) (citing David C. Rode and Paul S. Fishbeck, "Regulated Equity Returns: A Puzzle," 133 ENERGY POLICY 110891 (Oct. 2019) and linking to Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited" (May 2021, preliminary version)).

decades of utility-specific data about transmission investments, yet it does not appear to track utility performance or consider utility performance in its regulation. Our understanding is that utility compliance with existing reporting mechanisms (such as Form 1) is insufficiently standardized, and that the data is not granular enough to easily track project-by-project performance. It simply cannot be the case that transmission development and asset maintenance are immune from analytics, or that utility-specific performance is irrelevant to the Commission's obligations as a utility regulator. Because competition does not discipline local transmission decisionmaking and costs, regulation must "assur[e] good performance."[10] Yet Commission regulation is indifferent to whether it is motivating efficiency or rewarding wastefulness and reckless spending. Commission orders do not reflect which utilities consistently develop projects on-time and on-budget and which do not. Utility-specific performance metrics would shed light on poor performers and allow customers, state regulators, and the Commission to take appropriate action. We urge the Commission to begin collecting data that can answer material questions about utility performance.

Local Transmission Planning Under Order No. 890 and Planning for Asset Management Projects

1. Local "planning" processes are forums where utilities to divulge limited information about self-planned projects. In Order No. 890, the Commission seemed to intend something different. Because it could not "rely on the self-interest of transmission providers to expand the grid in a non-discriminatory manner,"[11] the

[10] Alfred E. Khan, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, Vol. 1, 20 (1970) ("The essence of regulation is the explicit replacement of competition with governmental orders as the principal institutional device for assuring good performance. . . . Price regulation is the heart of public utility regulation.").

[11] Order No. 890, 118 FERC ¶ 61,119 at P 422 (2007).

Commission ordered utilities to "coordinate with customers, neighboring transmission providers, affected state authorities, and other stakeholders in order to ensure that transmission plans are not developed in an unduly discriminatory manner."[12] The Commission expected that planning processes would "provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers."[13] But actual compliance appears to have generally failed to live up to that vision. Instead, as the Commission then feared, local processes are typically "limited to the mere exchange of information and then review of transmission provider plans after the fact."[14]

a. With regard to local planning criteria, the record shows that stakeholders "simply don't have enough information" to propose alternatives to utility projects or question utility decisions.[15] Even when utilities match local planning criteria to specific projects, the record shows that stakeholders have no insight into "criteria that go into th[e] decision making process, like end of life for facilities, or cost considerations, or public policy considerations, or all of those other considerations

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[12] *Id.* at P 438.
[13] *Id.* at P 488.
[14] *Id.*
[15] Technical Conference Transcript at 60:13−16 (Chair Chandler, Kentucky PSC: "Because we can't understand how they're using their criteria, there's no way to replicate or be able to determine whether they're identifying those correctly, and whether they actually exist."); *id.* at 28:4–7 (Chair Chandler making a similar observation about the PJM M-3 local process); *id.* at 56:23–57:2 (Lisa McAlister, General Counsel for Regulatory Affairs, American Municipal Power: explaining that stakeholders have not proposed alternative projects because "we simply don't have enough information . . . we don't [know] how those replacements are prioritized. We don't know whether replacement versus maintenance decisions, how those are made, how assets rank relative to other assets on the system."); *id.* at 63:16–64:11 (Bill Pezalla, Old Dominion Electric Cooperative). Filings in Docket RM21-17 also discuss lack of transparency in local planning processes. *See* Oct. 12, 2021 comments of: Michigan PSC at pp. 8–10, Pennsylvania PUC at pp. 16–18, Office of the Ohio Consumers' Counsel at pp. 12–15, New Jersey BPU at pp. 4–7, National Association of Regulatory Utility Commissioners (NARUC) at pp. 48–49, Transmission Access Policy Study Group at pp. 24–25, American Municipal Power at pp. 24–32, California Municipal Utilities Association at pp. 8–9, Resale Power Group of Iowa at pp. 4–11.

that might come into play behind the scenes where [the utility] selects one project over another."[16]

The Commission should ensure that any new transparency requirements about local planning criteria provide value to customers. Ideally, transparency would facilitate participation by customers and stakeholders in an actual planning process. But there are numerous barriers and deterrents to stakeholder engagement in planning,[17] including that the utility makes the planning decisions and can choose to ignore stakeholder input.[18]

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[16] Technical Conference Transcript at 30:6–21 (Dan O'Hagan, Assistant General Counsel & Manager of Regulatory Compliance, Florida Municipal Power Agency: "As part of the 890 process we get the baseline reliability criteria from the transmission providers, and then the transmission provider specific engineering criteria for their projects, and that's all. We don't get other criteria that go into that decision making process like end of life for facilities, or cost considerations, or public policy considerations, or all of those other considerations that might come into play behind the scenes where they select one project over another. . . . We don't know the why they chose project A over the B, C, D, et cetera."); *id* at 57:11–12 (Lisa McAlister, American Municipal Power: "We don't have a lot of insight into how the decision making has actually happened.").

[17] Technical Conference Transcript at 118:23–119:4 (Greg Poulos, Consumer Advocates of PJM States: "We have the money to hire an expert. I just don't know what our expert would do with only 10 days to review projects, no ability to ask the questions, and no expectation that they're going to respond to us."); *id.* at 33:6–10 (Lisa McAlister, American Municipal Power: "To really have a meaningful opportunity to have a back and forth you need more than just the ability to submit comments. There has to be some actual requirement that the transmission owners respond."); *id.* at 57:18–23 (Lisa McAlister: " I know that [utilities] use a lot of proprietary tools you know to rank how they're going to do their local planning. . . . I'm simply saying that those are proprietary and you know can't share the information has been something that's been thrown out to us, and you know PJM does have a process where you can request the CEII information, but it's been a barrier to be able to gather the information."); *id.* at 189:23 (Michael Haugh, Office of the Ohio Consumers' Counsel: "A lot of times we don't know what we don't know."); *id.* at 191:21–192:7 (Chairman Gerwatowski, Rhode Island Public Utilities Commission: "If we get information, the question is what would we do with it. . . . Suppose that we in the states, maybe it's NESCOE, maybe it's that one state that's looking at information. We'd hire someone and we'd start asking. Well at that moment the lawyers descend with their shields and swords, and it becomes a fight. And so it's not really conducive to a cooperative effort that tries to get to the right answer."). Comments filed on August 17, 2022 in Docket No. RM21-17 raise concerns about CEII preventing participation. *See* Comment of Southern Renewable Energy Association at p. 28; Comments of the Colorado Office of the Utility Consumer Advocate at pp. 25, 29; Comments of Pine Gate Renewables at pp. 15–16; Initial Comment of American Municipal Power at pp. 21–22; Initial Comments of Joint Consumer Advocates at p. 22.

[18] Utility control can be enshrined in utility tariffs. *See, e.g.,* NorthWestern Corporation, Montana OATT, Attachment K, Preamble, p. 1 ("The Transmission Provider retains the responsibility for the local planning process and Local Transmission Plan and may accept or reject, in whole or in part, the

Nonetheless, transparency about planning criteria could protect consumers. Disclosures might help customers and stakeholders assess whether utility projects are unnecessary, excessive, or duplicative or whether the utility unreasonably overlooked lower cost alternatives, such as maintenance or non-transmission alternatives.[19] Ultimately, this information might be relevant for successfully challenging transmission rates or building a record that could ultimately protect customers from utility abuses.[20] For example, the Commission could require utilities to:

- Disclose all local planning criteria and provide timely updates;
- Identify which planning criteria are driving each expansion or asset replacement project;
- Explain how planning criteria and other factors inform project prioritization and selection; and
- File local planning criteria under section 205.

comments of any stakeholder unless prohibited by applicable law or regulation"); The PJM OATT requires utilities to "review and consider comments that are received within 10 days of the [Planning] Meeting" and does not require the utility to respond to any comments ("may respond or provide feedback as appropriate)." PJM OATT, Attachment M-3 sec.(c). *See also* Technical Conference Transcript at 106:5–17 (Greg Poulos, Consumer Advocates of PJM States: "The transmission owners . . . have said we have no control of whether we're going to do the grid enhancing technologies. You have no input on this. It is our ability to do this. And some have done it. And there are some programs going forward, but it has been very clear even in a discussion which we're having about dynamic line rating, that the transmission owners will have all control over the process, whether PJM likes it, whether stakeholders like it, we do not have any say in whether it will happen based on that the consolidated transmission owner agreement and some of the provisions in there."); *id.* at 160:24–161:5 (Adrienne Mouton-Henderson, Clean Energy Buyer's Association: "The stakeholder process is a check the box exercise . . . it's not real. We don't get a lot to say, and then when we do say it no one is really listening.").

[19] NERC criteria "only establishes a floor or minimum requirements for the purposes of designing and planning power transmission infrastructure." They do not set "any upper limits or requirements [for utilities] to plan their transmission infrastructure to be capital cost efficient, in line with good planning practices." Consumer Advocates of PJM States, *Expert Consultation on PJM Supplemental Transmission Projects: Standards and Oversight* (Sep. 2019).

[20] Evidence could be relevant for future Commission rulemakings, for instance.

On the last point, local planning criteria that drive transmission expansion and asset replacement projects undoubtedly "directly affect" jurisdictional rates.[21] The Commission has legal authority to impose this filing requirement. Although the Commission might not have the capacity to scrutinize local planning criteria in the near term, there may long-term benefits to instituting this new filing requirement. Having all local planning criteria on file would facilitate comparisons across the industry by customers or other parties that could lead to improvements.[22] Eventually, such efforts might inform Commission-enforced minimum standards. The Commission routinely reviews technical transmission rules to ensure they result in just and reasonable rates and not unduly discriminatory service. Local planning criteria should be similarly evaluated.

There may also be shorter term implications for customers. The record shows that some utilities in MISO may be "cooking the books" with local criteria in order to saddle interconnecting generators with additional costs.[23] In addition, filing requirements would facilitate scrutiny of utility investments and prevent utilities from charging customers for projects driven by unreleased planning criteria.[24] For example, at a MISO-hosted local planning meeting in February 2023,[25] Entergy disclosed a $160 million 230 kV line.[26] Seven years earlier, MISO had found that essentially the same line (identical voltage and termination points) would have a

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[21] FERC v. Electric Power Supply Ass'n, 577 U.S. 260, 276 (2016).
[22] Presumably utilities have their own forums for sharing planning practices. But utilities do not hold monopolies on good ideas. Sharing planning criteria and matching those criteria to decisions might facilitate outside analysis.
[23] Technical Conference Transcript at 72:23–73:16.
[24] *See* Initial Comment of Alliant Energy, Consumers Energy, and DTE Electric, Docket No. RM21-17, Oct. 12, 2021 at p. 25 (noting that "transmission owners can unilaterally change their local planning criteria and there is very little review of those changes, even though such changes can have a significant effect on transmission expansion costs imposed on customers").
[25] MISO, South Subregional Planning Meeting, Meeting Materials (Feb. 3, 2023).
[26] MTEP23 Project Information for Louisiana Utilities (Feb. 3, 2023).

benefit-cost ratio of 2.3 and approved it as an "economic" project in its regional plan.[27] But before construction started, MISO cancelled the project. It found that the benefit-cost ratio dropped to 0.2 due mostly to subsequent transmission development and the presence of a new natural gas power plant in the vicinity.[28] At the February 2023 meeting, a stakeholder asked an Entergy representative why it was proposing a project that MISO had cancelled just two years earlier due to its low benefit-cost ratio. Entergy responded that the project was now needed due to a new local planning criteria about resilience. No documentation about this criteria appears on Entergy Louisiana's OASIS.[29]

This new resilience criteria — which Entergy claims justifies reviving a recently cancelled $160 million investment[30] — is driving $2.1 billion in new local projects that will be paid for by Entergy Louisiana ratepayers.[31] Stakeholders noted that the scale of Entergy's proposed projects, which total almost $4 billion across its Texas and Louisiana utilities and include two 500 kV projects costing $2.5 billion,[32] suggest that Entergy is circumventing MISO's regional planning process. By designating projects as local, Entergy evades MISO's competitive bidding process, avoids the risk that MISO cancels a project down the line, and escapes scrutiny MISO applies to costs of regional projects.

[27] MISO, Waterford-Churchill 230 kV Economic Project Withdrawal (Oct. 9, 2020); MISO determined that the project would "improve import capability" and would "provide operational flexibility" and "enhanced resilience." *Id.;* MTEP16 at p. 105.
[28] MISO, Waterford-Churchill 230 kV Economic Project Withdrawal (Oct. 9, 2020).
[29] The only version of Entergy Louisiana's local planning criteria we could find is from 2007: Entergy Transmission Local Planning Criteria.
[30] For the project at issue, Entergy provided three bullet points outlining the project need. Two of those bullets reiterate MISO's 2016 findings and the third alludes to the missing resilience local planning criteria.
[31] Entergy Louisiana proposed a total of $2.7 billion of local projects, and provided that "resilience" is a major driver of $2.1 billion in projects.
[32] Entergy Louisiana proposed a $1.4 billion project that includes 60 miles of new 500 kV lines and new 230 kV lines. *Id.* Entergy Texas proposed a $1.1 billion project that includes 150 miles of 500 kV lines. MTEP23 Project Information for Texas Utilities (Feb. 3, 2023).

Publishing the new resilience criteria would not remedy all of the deficiencies of this so-called planning process. At the first of its three annual local-plan presentations, Entergy disclosed only project termination points, estimated costs, and high-level justifications.[33] Stakeholders could do little with the information Entergy provided. However, given that this criteria is driving $2.1 billion in local expansion projects in Louisiana alone, a filing requirement would fill one significant gap in Entergy's inadequate process.[34]

b. In the regional planning and cost allocation NOPR, the Commission expressed "concern[] that local transmission planning processes may lack adequate provisions for transparency and meaningful input from stakeholders."[35] "[L]ack of minimal standards or specified procedures to implement these principles may contribute to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes."[36] The Commission also expressed "concern" that "many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating whether those replacement transmission facilities could be modified (i.e., right sized) to more efficiently or cost-effectively address regional transmission needs."[37] The Commission's proposed reforms aimed primarily at identifying

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[33] *Id.*

[34] In PJM, a 2019 analysis found that "TOs do not appear to be making regular or periodic updates to their standards," and "there is little to no PJM oversight or due-diligence on how and when the criteria are being submitted, or what is being submitted as part of the criteria. It appears that PJM does not enforce uniformity or minimum standards on the planning criteria that the TOs are submitting to PJM which are eventually published on PJM's website. TO planning criteria vary significantly on details and frequency at which planning criteria are published." Consumer Advocates of PJM States, *Expert Consultation on PJM Supplemental Transmission Projects: Standards and Oversight* (Sep. 2019).

[35] Regional Planning NOPR at P 398.

[36] *Id.*

[37] *Id.* at P 399.

opportunities to incorporate into the regional planning process needs identified in local planning processes.

Regardless of the Commission's approach in a final regional planning rule, the Commission should establish minimum transparency standards for local planning processes. There is no justification for confidentiality. Local planning is not subject to competition, and all projects are paid for by the utilities' captive ratepayers. There are no trade secrets that deserve protection. The Commission should exercise its broad authority to require utility disclosures.[38]

Specific disclosure requirements are necessary because the general transparency directive in Order No. 890 has proven insufficient.[39] The record shows that existing disclosures are insufficient. Stakeholders and regulators "have no idea" whether utilities are prioritizing "certain asset conditions over others" because utilities only give information to only provide "the appearance of transparency, and . . . it's not enough to have an appreciation for how they're actually doing local planning."[40]

We do not intend to provide an exhaustive list of relevant data that might immediately benefit customers, stakeholders, and state regulators and allow the Commission to build a long-term record of utility performance. For each project, the utility should provide at least the following information: projected budget, in-service

[38] *MISO, et al.*, 143 FERC ¶ 61,149 at P 84 (2013) (noting that "the Commission has discretion to prescribe the manner in which public utilities are to make available their books and records to the Commission" and that it has "authority to require utilities to make available detailed information regarding their formula rates and inputs") (citing 16 U.S.C. §§ 825, 825h; Order No. 667, 70 Fed. Reg. 75,592 at P 52 (2005); *Idaho Power Co.*, 115 FERC ¶ 61,281, at P 29 (2006)).

[39] In Order No. 890, the Commission required utilities to "include sufficient detail to enable Transmission Customers to understand . . . [t]he methodology, criteria, and processes used to develop transmission plans." Order No. 890, Appendix C, Pro Forma Open Access Transmission Tariff, Attachment K.

[40] Technical Conference Transcript at 28:8–15; *id.* at 137:17–20 (Nick Guidi, Southern Environmental Law Center: "So if any lines are upgraded, or rebuilt, or just completely wholesale replaced, there's no CPCN for a lot of those. So they don't show up until they're just an expenditure line item in a retail rate case."). *See also supra* notes 15–18.

dates, quantifiable and qualitative project benefits, transmission and non-transmission alternatives considered, relevant local planning criteria, permits anticipated to be requested from local, state, and federal agencies, specific transmission customers (if any) that are expected to directly benefit from the project, and details of consultations with customers, neighboring transmission owners, and regional planning entities about the project. In addition, the utility must provide a detailed narrative explanation of the methodology the utility used to select each project.

The Commission should also extend Order No. 890 to include asset replacement projects. In Order No. 890, the Commission overlooked the possibility that utilities might unduly discriminate by failing to expand the grid at all. In the regional planning NOPR, the Commission recognized that in-kind replacements "may result in the development of duplicative or unnecessary transmission facilities that increase costs to consumers" because they fail to account for regional needs.[41] It is also possible that in-kind replacements do not account for local needs, and the utility may nonetheless replace existing assets to avoid disclosure or permitting requirements or for other reasons.

The Commission should not rely on the self-interest of transmission providers to choose between in-kind replacement and expansion projects in a nondiscriminatory manner. Local transmission needs may be changing rapidly due to growth of distributed energy resources (DERs). The Commission has acknowledged that DERs can affect transmission needs and rates.[42] Utilities that oppose DER adoption may be inclined to discount their potential impacts on local transmission needs. Such a utility could unduly discriminate against DER owners (who may be utility

[41] Regional NOPR at P 399.

[42] *See, e.g., ISO New England, et al.*, 178 FERC ¶ 61,115 at P 7 (2022) (noting that a generation project connected to the distribution system necessitated transmission upgrades).

competitors) by rebuilding its local transmission system without accounting for the potential growth of DERs. Disclosure requirements would allow customers and other stakeholders to build a record that may be relevant to local planning and useful for future rate challenges or other proceedings against the utility.

c. No response.

2. As discussed above, the Commission should close the asset management loophole. The Commission's policies provide utilities with what amounts to a blank check that may be worth hundreds of billions of dollars over the next few decades. Without an obligation to disclose project justifications, timelines, or budgets, utilities are wholly unaccountable for their asset replacement decisions and spending. Regulators have no basis for evaluating the utility's performance, and customers have no recourse for escalating bills. Blindly trusting the monopolist with billions of dollars of customer money is inconsistent with basic assumptions of utility regulation and shreds the consumer protections embedded in the FPA.

a. Without any paper trail documenting the utility's asset replacement decisions, regulators and customers have no basis for determining whether the utility is acting prudently. While there is no doubt that transmission infrastructure is aging, it is plausible that utility self-interest is driving capital expenditures and discounting the potential value of maintenance to existing facilities. Moreover, the Commission has recently recognized that supply and demand are changing rapidly, potentially affecting transmission needs and rendering a rebuild project obsolete.[43] The current laissez faire approach sets up a double dip windfall. Utilities might

[43] *See, e.g.,* Regional NOPR at P 171.

profit from an asset replacement project today and later profit by revisiting that project down the line, such as by reconductoring it to increase its capacity.[44] Without any record evidence on asset replacement projects, stakeholders will have no basis for later challenging utility expenditures, and regulators will have no basis for later questioning the utility's judgment.

We do not have experience with the California procedures and so do not express an opinion on whether they provide a national model. The Commission should ensure that its policies are not incentivizing utilities to rebuild last century's local transmission system rather than invest in its future. At the very least, the Commission should require utilities to document asset replacement decisions, including whether to expand a line's capacity, why additional maintenance was not a viable alternative to replacement, and whether to implement twenty-first century solutions, such as grid-enhancing technologies and non-transmission alternatives. As discussed in our response to 1.b, growth of distributed energy resources may be changing local transmission needs. While many DER issues are regulated by states, the Commission has exclusive authority over transmission planning — as well as terms and conditions of service — and should not shirk its responsibility to ensure just and reasonable and not unduly discriminatory rates with the hope that states will exert greater oversight in permitting processes.

b. No response.

3. The Commission should impose project-specific disclosure requirements. The evidence shows that stakeholders lack project-specific information or that utilities

[44] *See* Technical Conference Transcript at 64:6–11 (Bill Pezalla, Old Dominion Electric Cooperative expressing this concern).

make it available in unusable formats.[45] In response to 1.b, we provide a non-exhaustive list of project-specific information utilities should disclose during the planning process. We reiterate that there is no justification for secrecy. Confidentiality benefits utilities and harms all other interests. The Commission should err on the side of over-disclosure and transparency.

We see three main benefits of this additional transparency. First, under the theory that "sunlight is said to be the best of disinfectants; electric light the most efficient policeman,"[46] disclosure might lead to different outcomes.[47] Developing project-specific data, analysis, and justifications might cause the utility to adopt different internal project development processes or reevaluate particular projects. Second, project-specific disclosures will provide customers, state regulators, and

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[45] Technical Conference Transcript at 30:9–14, 31:4 (Dan O'Hagan, Assistant General Counsel & Manager of Regulatory Compliance, Florida Municipal Power Agency) (explaining that at its planning meeting, one utility only reveals a few of its planned projects and "[t]he rest of it just shows up in the [Florida Reliability Coordinating Council] FRCC data base, and it is difficult for us, and especially for some of the smaller stakeholders just from time and resources, to be able to glean from that what the projects are because we only see differences in ratings, or differences in impedances, or differences in the way things connect and have to compare that to last year's models to be able to identify a difference. And that's difficult to do, and a time consuming thing to do. And if they're not identifying those projects for us, and it's take that difficult time to find those, it becomes very difficult to both keep a check on those, and then identify again as I sound like a broken record, but start identifying solutions in the regional process."); *id. at* 76:23–77:3 (Jennifer Easler, Iowa Office of Consumer Advocate: "[W]hen a utility wants to replace a [ ] line because of age and condition, the regulator is hard pressed to say no. What we really need is the review ahead of time to make sure that those aging condition projects are being fed into the overall solution."). *See also supra* notes 15–18.

[46] Louis D. Brandeis, "What Publicity Can Do," HARPER'S WEEKLY (Dec. 20, 1913).

[47] *See also* Technical Conference Transcript at 211:1–23 (Chairman Gerwatowski, Rhode Island Public Utilities Commission: "I worked for a utility . . . for 28 years . . . I'm certain that utilities . . . will tell you with sincerity that they have procurement programs, they do variances, they look at alternatives, and they care about costs. But I can say that if you look past in the history and you never see a disallowance, and you never see anything that's been challenged . . . And that is the history for the past 10 to 15 years. Then the utility is going to lose sight of that, and it's not going to be a priority, and they're not going to be thinking about it, and the engineer is not going to be thinking about it, the financial folks aren't going to be thinking about it because there's no risk. And I think one of the parts about having an independent monitor here is that it suddenly brings if oh, there is a risk here. We've got to be paying closer attention to it.").

other stakeholders with information needed to track projects and spending and ultimately challenge utility-filed rates or bring another action against the utility. Third, the Commission could accumulate and analyze this data to develop long-term performance assessments of each utility. Ultimately, the Commission might account for utility performance in its regulations.

As we discuss in more detail in our response to questions 6 and 7, Commission policies have made it all but impossible for customers to challenge transmission rates. Lack of information is a key obstacle to viably protesting a utility rate. Secrecy shields utilities from scrutiny and renders customers powerless. Because project-specific disclosures might affect local planning outcomes and could inform rate cases, utilities should be required to disclose project-specific information in both proceedings. As discussed, disclosures should cover expansion and asset replacement projects.

Project Implementation and Variance Analysis

4. No response.

Independent Transmission Monitor

5. A Ratepayer Transmission Monitor (RTM) would provide technical expertise to customers and stakeholders that lack the capacity and resources needed to track utility transmission plans and expenditures.[48] Customers and state-recognized

[48] Technical Conference Transcript at 85:13–86:5 (James McLawhorn, Public Staff, North Carolina Utilities Commission: "We simply do not have the expertise on staff. . . . We do not have particular transmission expertise on staff, and we desperately need something like an independent transmission monitor. . . . we can ask [for] information, and we can get information, but to try to evaluate that we don't have access to the models. We need someone who has some expertise in that area who can assist us in that review, both for IRP purposes, for CPCN purposes."); *id.* at 43:20–23 (Lauren Azar: "I can tell you that Wisconsin, unlike many other states, actually does have transmission modelers, but they don't have the ability to model on a much more regional basis."); *id.* at 189:19–190:2 (Michael Hough, Office of the Ohio Consumers' Counsel: "The one issue that we

ratepayer advocates would contract with a utility-specific RTM and define its scope of work, although an RTM must perform the functions specified by a final rule on RTMs. PJM's tariff provisions that fund Consumer Advocates of the PJM States (CAPS) provide a model for funding an RTM through a transmission tariff.[49]

The Commission's "independent entity variation" policy provides a basis for requiring an RTM only for utility-run planning processes.[50] Alternatively, the Commission could encourage utilities to adopt an RTM, rather than imposing it through a section 206 proceeding. For instance, for any utility that adopts an RTM through a section 205 filing, the Commission could continue to presume that all of its transmission costs are prudently incurred and would allow it to recover those costs via formula rates. For utilities without an RTM, the utility would have to prove that its self-planned projects are prudent. In response to question 7, we suggest additional criteria for narrowing the scope of projects. That burden of proof would prevent utilities from automatically recovering capital costs of self-planned projects through existing formula rate processes.

The RTM's data gathering and analysis would help the Commission fill an important gap in its transmission rate oversight. To ensure just and reasonable rates, the Commission relies on stakeholder involvement and ratepayer challenges. The Commission's transparency rules in planning processes and formula rate proceedings attempt to empower customers and ratepayer advocates so they can

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have, and I think it's been stated before as consumer advocates we have smaller offices. We have limited resources . . . the independent transmission monitor is someone that can come in and help us walk through and explain."); *id.* at 116:4–21 (Jennifer Easler: "I think for consumer advocates, having enough resources is just a constant problem. And when we transferred authority over transmission to the federal level we didn't really think about well how are we going to do everything both at the local level and then at the federal level. . . .").

[49] *See* PJM Tariff, Schedule 9-CAPS; *PJM Interconnection*, 154 FERC ¶ 61,147 (2016), *reh'g denied*, 157 FERC ¶ 61,229 (2016).

[50] *See supra* note 5.

viably participate and challenge utility decisions.[51] Evidence shows, however, that customer and stakeholder involvement has not been an adequate substitute for direct oversight.[52] So long as the utility follows its own rate formula, it will recover every dollar it spends. An RTM, combined with new disclosure mandates, could counteract the information asymmetry between a utility and its customers and enable meaningful participation in planning processes and rate proceedings.

Independent Transmission Monitors (ITMs) would have limited roles in regional planning processes run by an RTO or other planning entity that is independent of transmission owners. An ITM would: 1) publish periodic “State of the Network” reports and 2) monitor the regional planning process for evidence of undue discrimination.

a. For utility-run planning processes, we suggest that the Commission set a minimum scope of work for RTMs and allow customers and stakeholders to provide additional duties. During a utility-run planning process, an RTM's minimum scope of work would include: participating in stakeholder meetings; reviewing utility-disclosed information; assessing estimated project costs, benefits, and drivers; suggesting project alternatives (including non-transmission alternatives); and providing feedback to the utility on behalf of customers and stakeholders. Following

[51] *See, e.g.,* Order No. 890 at P 471 (“This information should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.”); *MISO, et al.*, 139 FERC ¶ 61,127 at P 15 (“The lack of a formal discovery process and procedures to require the transmission owner to answer a party's reasonable information requests may make the formula rate protocols unjust and unreasonable”); *MISO, et al.*, 143 FERC ¶ 61,149 at P 83 (“To be just and reasonable, the MISO formula rate protocols must be revised to provide interested parties with the information necessary to understand and evaluate the implementation of the formula rate for either the correctness of inputs and calculations, or the reasonableness of the costs to be recovered in the formula rate.”).
[52] *See supra* notes 15–18.

the completion of the plan, the RTM would write a report evaluating both the utility's plan and the planning process. The RTM would also track utility projects to alert customers and stakeholders of delays and cost overruns. We assume that enhanced disclosure requirements (see responses to questions 1, 2, and 3) will facilitate the RTM's analysis and there would be no need for the utility to provide additional data to the RTM. If the utility is not providing sufficient data, an RTM should be allowed to file a complaint with the Commission.

For planning processes run by an independent entity, the ITM's role would be more limited. Under current regional planning rules, RTOs are supposed to discipline incumbents by allowing non-incumbent developers to propose and build projects, re-evaluating project benefits and costs prior to construction, and tracking costs during construction. There is no need for an ITM to perform duplicative work.

We propose two tasks. First, the ITM would gather evidence of potential undue discrimination by tracking how the regional planning entity: 1) accounts for utility-defined local needs, 2) evaluates projects proposed by non-incumbent developers, and 3) responds to stakeholder feedback. Second, the ITM would publish periodic "State of the Network" reports that would provide objective, data-driven accounts of the regional network. These reports would document constraints, outages, and other physical properties and parameters of the network, including an evaluation of transmission facility ratings.[53] ITM reports would also catalogue implementation of non-wires solutions, such as operational practices and adoption of grid-enhancing technologies, and identify opportunities for additional deployment. The reports would provide stakeholders and the Commission with an independent assessment of

[53] In Order No. 881, the Commission required utilities to share line ratings and methodologies with market monitors. Utilities should also share that information with ITMs. To the extent that ITMs and market monitors might then be performing duplicative work, these entities should decide among themselves how to efficiently use their resources. Order No. 881, 177 FERC ¶ 61,179 at P 331 (2021).

the regional network, akin to periodic market monitor reports. We justify the need for these ITM functions in response to question 5.b.

b. RTMs and ITMs will protect consumers by gathering and synthesizing information that might be relevant to customers, stakeholders, and state regulators. RTMs and ITMs will help ensure that Commission-jurisdictional rates and processes are just and reasonable and not unduly discriminatory.

RTMs will help counteract the information asymmetry between utilities and customers. As we discuss elsewhere in this filing, the Commission should order utilities to disclose additional information in utility-run planning processes and formula rate annual update proceedings. An RTM will provide information to customers and stakeholders that is digestible and useful. The RTM's technical expertise will benefit customers in regulatory proceedings.[54] By enhancing stakeholder involvement in planning processes and customer challenges in rate proceedings, an RTM will help the Commission ensure just and reasonable rates.

ITMs will protect transmission customers and non-incumbent developers from undue discrimination and identify the most cost-effective non-transmission solutions to congestion and other network issues. The Commission's planning rules provide transmission providers with "significant discretion"[55] in setting evaluation criteria for potential transmission solutions,[56] which can facilitate unduly

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[54] A 2019 report published by Consumer Advocates of PJM States (CAPS) found that state regulators and consumer advocates typically lack the technical skills to evaluate local transmission need and costs and that the recent increase in volume of local projects has heightened the need for additional technically competent staff. Consumer Advocates of PJM States, *Expert Consultation on PJM Supplemental Transmission Projects: Standards and Oversight*, at pp. 18–19 & 22–23 (Sep. 2019).
[55] Order No. 890 at P 26.
[56] *See, e.g.,* Order No. 1000-A, 139 FERC ¶ 61,132 at P 267 (2012) (declining "to adopt standard procedures in the regional transmission planning process for evaluating backbone transmission facilities or for addressing transmission upgrades that have a short planning and construction cycle and that can be adapted to fill economic or reliability needs as they arise in the ordinary course of

discriminatory conduct and implementation of sub-optimal solutions that benefit incumbents. While that theoretical concern about undue discrimination is sufficient to justify Commission action,[57] a recently revealed agreement between PJM and its transmission owning members highlights an urgent need for oversight. The confidentiality agreement allowed PJM utilities to develop section 205 filings with the assistance of PJM.[58] Through their confidential collaboration on local planning and cost allocation, PJM utilities and PJM expanded the scope of utility-planned projects and scaled back regional competition.[59] This anti-competitive result emphasizes the need for an independent watchdog to guard against the possibility that the "broad discretion" inherent in regional transmission planning may allow a transmission provider to collude with its transmission-owning members in order to "discriminate in subtle ways against [their] competitors."[60]

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system operations"); *id.* at P 271 (declining to require analyses of loop flow in planning processes); *id.* at P 283 (affirming that transmission providers may use "flexible criteria or bright-line metrics" to determine which projects are in the regional plan).

[57] Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 688 (D.C. Cir. 2000) (citing Associated Gas Distributors v. FERC, 824 F.2d 981, 1008–09 (D.C. Cir. 1987)); National Fuel, 468 F.3d 831, 839–844 (D.C. Cir. 2006); Louisiana Pub. Serv. Comm'n v. FERC, 551 F.3d 1042, 1045 (D.C. Cir. 2008); Sacramento Mun. Util. Dist. v. FERC, 616 F.3d 520, 542 (D.C. Cir. 2010); Order No. 1000-A at P 9 (The Commission "need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination."); *id.* at P 58 ("The court [in *National Fuel*] specifically stated that the Commission could choose "to rely solely on a theoretical threat"); *id.* at PP 63–65, 80.

[58] In a proceeding about cost allocation, various parties have made representations to the Commission about the arrangement in FERC Docket No. EL21-39. LSP Transmission Holdings II, Comment in Support (Feb. 9, 2021); PJM Interconnection, Motion for Leave to File Answer and Answer (Feb. 25, 2021); Indicated Transmission Owners, Answer (Mar. 4, 2021); Silver Run Electric, Response to Request for Abeyance (Mar 5. 2021); Indicated Transmission Owners, Motion for Leave to File Answer and Answer (Mar. 22, 2021).

[59] *See, e.g,, PJM Interconnection*, 154 FERC ¶ 61,096 (2016) (accepting PJM transmission owners' proposal to allocate all costs of certain projects to the host transmission owner and thus exempting such projects from competition), *reversed*, Old Dominion Electric Cooperative, et al. v. FERC, 898 F.3d 1254 (D.C. Cir. 2018); *PJM Interconnection*, 172 FERC ¶ 61,136 (2020) (accepting transmission owners' proposed changes to local planning over the objections of stakeholders who filed a different proposal) (appeal pending before the D.C. Circuit).

[60] Order No. 890 at P 68.

In addition, evidence in other proceedings demonstrates that transmission owners, and not RTO/ISOs, decide whether to implement modern operational practices or deploy grid-enhancing technologies.[61] Transmission-owning utilities are generally disincentivized from adopting cost-effective technologies and using accurate line ratings because these measures may reduce the need for profitable capital expenditures.[62] An ITM would aim to expose such potentially self-interested behavior by transmission owning utilities.

c. No response.

d. An RTM should be able to perform its duties based on information that utilities release pursuant to future Commission disclosure rules. As discussed in response to questions 1, 2, and 3, the Commission should subject utilities' local planning processes to sweeping disclosure rules. There is little justification for confidentiality when there is no competition and captive ratepayers pay for all project costs. The Commission has legal authority to specify disclosure requirements and prohibit utilities from withholding information.[63] We also suggest that the Commission consider revisiting its current CEII policy, particularly with

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[61] *See, e.g.,* Order No. 881, 177 FERC ¶ 61,179 at P 9 (2021) ("requir[ing] RTOs/ISOs to establish and maintain the systems and procedures necessary to *allow transmission owners* in their regions to electronically update transmission line ratings on at least an hourly basis") (emphasis added).
[62] *Id.* at P 68 (summarizing comment of Potomac economics that "transmission owners have little or no economic incentive to provide temperature-adjusted ratings"); *id.* at P 79 (summarizing comment of Industrial Customer Organizations "that some transmission line ratings may be deliberately understated because transmission owners may have a profit incentive to calculate understated transmission line ratings in order to benefit local generation"); *id.* at P 312 (summarizing comment of New England State Agencies "that transmission owners may have an incentive to be overly conservative with transmission line ratings methodologies because there is no financial incentive for more efficient operation of existing transmission assets and there is significant incentive for transmission owners to build new transmission lines and substations and include these new assets in their rate base").
[63] *Supra* note 38.

regard to local facilities, which the Commission imposed weeks after the September 11 attacks.[64]

ITMs should have access to all transmission system information. To the extent utilities and RTO/ISOs are unwilling to supply relevant information, the ITM should be allowed to file a complaint with the Commission.

e. The Commission should not mandate an automatic sunset provision in tariffs instituting an RTM or ITM, and it should reject any utility efforts to include such a condition. Contracts between RTMs and customers, or between ITMs and RTOs, ought to have a reasonable term to ensure that ratepayers are not locked in to an ineffective transmission monitor.

f. RTMs and ITMs would be funded through relevant tariffs. For an RTM, the captive ratepayers that pay for a utility's local projects would set the RTM's budget, establish the RTM's duties, and appoint the RTM. The Commission could issue pro forma tariff provisions that set a default RTM budget and scope of work and allow a transmission customer committee to modify those defaults. Committee votes would be allocated based on each customer's share of the utility's transmission revenue requirement, with direct representation cut off at a Commission-set minimum

[64] On October 11, 2001, the Commission removed utility Form 715 filings and other materials from its website. It stated that "[t]he September 11, 2001 terrorist attacks on America have prompted the Commission to reconsider its treatment of certain documents that have previously been made available through the Commission's internet site . . ." *Statement of Policy on Treatment of Previously Public Documents*, Docket No. PL02-01. Less than eighteen months later, the Commission was "unconvinced that the general public's need for information warrants the risk of disclosure of Critical Energy Infrastructure Information." Order No. 630, *Critical Energy Infrastructure Information*, 102 FERC ¶ 61,190 (2003). On rehearing, the Commission stated that Order No. 630 "is not intended to limit the ability of companies . . . to share CEII with those with a need for it . . and the Commission encourages these entities to provide information to legitimate requesters." Order No. 630-A, 104 FERC ¶ 61,106 (2003).

share. All remaining customers would be represented by the state consumer advocate. Customers would have the option of pooling their shares together to reach the minimum percent. For instance, if direct representation were cut off at a five percent share of the utility revenue requirement, five municipal utilities each responsible for paying one percent of a utility's transmission revenue requirement could join together to reach the five percent minimum for direct participation in the committee. Voting shares would be recalculated every few years.

An ITM would be established via the independent planning entity's tariff. Existing RTO tariff provisions establishing market monitors appears to provide a reasonably good starting point for developing tariff provisions and agreements that implement ITMs.[65]

RTM duties would not overlap with any RTO/ISO functions. Some ITM reporting may overlap with existing RTO/ISO planning functions. As discussed, we suggest that an ITM produce periodic State of the Network reports that provide data about the regional transmission system, including congestion-causing constraints. RTO/ISOs may already identify such constraints as part of the regional planning process. Despite this overlap, we believe that the ITM's assessment will be valuable to consumers and the Commission. As discussed, the discretion inherent in transmission planning raises concerns that RTO/ISO processes may favor incumbent interests. ITM reports can either neutralize those criticisms or raise questions about existing planning processes. Ultimately, RTMs and ITMs can be as crucial as market monitors for ensuring just and reasonable rates. By providing much-needed information and analysis, RTMs and ITMs would indirectly "provide

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[65] *See, e.g.,* PJM Open Access Transmission Tariff, Attachment M: PJM Market Monitoring Plan; PJM Rate Schedule No. 46: Market Monitoring Services Agreement by and between PJM Interconnection, LLC and Monitoring Analytics, LLC.

the Commission with an additional means of detecting market power abuses, market design flaws and opportunities for improvements in market efficiency."[66]

g. The Commission has multiple options for encouraging or mandating the adoption of RTMs and ITMs. As discussed above, RTMs and ITMs would monitor planning processes and analyze information disclosed during those processes. RTMs would have a wider set of tasks because currently there is no independent entity reviewing plans or tracking expenditures of utility-planned projects. RTMs would be utility watchdogs, charged with scrutinizing all aspects of planning and implementation. Their mission would be to alert customers and stakeholders of the potential for unjust and unreasonable transmission rates as well as unduly discriminatory utility conduct. By contrast, ITMs would be focused on the potential for undue discrimination against non-incumbent developers as well as other anti-competitive conduct that benefits incumbents.

Requiring utilities and planning entities to adopt RTMs or ITMs would fall within the Commission's "broad authority to remedy unduly discriminatory behavior."[67] The FPA "fairly bristles with concern for undue discrimination,"[68] and courts have "consistently required the Commission to protect consumers against [transmission owners'] monopoly power."[69] The Commission's "authority generally rests on the public interest in constraining exercises of market power."[70] Where the Commission finds evidence of such anti-competitive conduct or even the potential for it, it has repeatedly acknowledged that it has "broad discretion in fashioning

[66] Order No. 2000, 89 FERC ¶ 61,285, at p. 190 (2000).
[67] Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 687 (D.C. Cir. 2000); South Carolina Pub. Serv. Authority v. FERC, 762 F.3d 41, 57–69 (D.C. Cir. 2014).
[68] Associated Gas Distributors v. FERC, 824 F.2d 981, 997 (D.C. Cir. 1987).
[69] United Distribution Cos. v. FERC, 88 F.3d 1105, 1127 (D.C. Cir. 1996).
[70] National Ass'n of Regulatory Utility Comm'rs. v. FERC, 475 F.3d 1277, 1280 (D.C. Cir. 2007) (citing Associated Gas Distributors v. FERC, 824 F.2d 981, 1003 (D.C.Cir.1987)).

remedies to undue discrimination."[71] The Commission's industry-wide remedies include reforms to rates and terms of service and have also targeted utilities' internal operations.[72] Mandating an RTM or ITM would not be more intrusive or burdensome than prior remedies to undue discrimination.

For RTMs, the Commission could find that the Order No. 890 planning principles are insufficient for remedying undue discrimination and that RTMs are necessary to address ongoing undue discrimination and ensure just and reasonable rates. Alternatively, the Commission could encourage utilities to adopt RTMs. As we discuss in response to question 7, the Commission has explained that administrative convenience justifies its current policy of presuming that all transmission expenditures are prudent.[73] But the Commission has no factual or theoretical basis for presuming that costs of utility-planned projects are prudently incurred or that rates recovering those costs are just and reasonable. To remedy this deficiency, the Commission could issue a supplementary prudence policy that

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[71] Order No. 890 at P 1322; *Consolidated Gas Co. of Florida, Inc. v. Florida Gas Transmission Co.*, 29 FERC ¶ 61,205 at p. 61,416 (1984); *James River Corp. of Nevada v. Northwest Pipeline Corp.,* 42 FERC ¶ 61,344, at pg. 9 (1988); *ANR Pipeline Co. v. Transcontinental Gas Pipe Line Corp.*, 91 FERC ¶ 61,066 at p. 61,233 (1991); *Missouri Gas Energy v. Panhandle Eastern Pipeline Corp.*, 75 FERC ¶ 61,166, at p. 61,549 (1996) ("[T]he Commission has 'broad power to stamp out undue discrimination,' including the authority to impose 'suitable remedies' in an appropriate case. That authority includes the power to order an interstate pipeline to transport gas, to add new delivery points, to file certificate applications, and to construct facilities necessary to make deliveries. The Commission's powers are at their height when it remedies a violation of the statute and its regulations.")(citations omitted); *Pennsylvania-New Jersey-Maryland Interconnection, et al*, 92 FERC ¶ 61,282, at p. 61,955 (2000).

[72] With its authority to remedy undue discrimination, the Commission has gone as far as mandating internal utility codes of conduct that restrict employees' communications and ordering utilities to share previously untracked data through new online platforms that meet Commission specifications. Order No. 889, *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, 61 Fed. Reg. 21,737, at p. 21,741 (1996); *id.* at p. 21,743, n. 28. *See also* Comment of the Harvard Electricity Law Initiative, Docket No. RM21-17 (Oct. 12, 2021) (discussing the Commission's authority to remedy undue discrimination and reviewing past uses of that authority).

[73] *Iroquois Gas Transmission System,* 87 FERC ¶ 61,295, at p. 62,168 (1999) (quoting *Minnesota Power & Light Co.*, 11 FERC ¶ 61,312, at pp. 61,644–45 (1980) (stating that FERC adopted this policy as "a matter of procedural practice to ensure that rate cases are manageable").

makes its prudence presumption contingent on the utility adopting an RTM.[74] For utilities that file RTM proposals that are consistent with or superior to the pro forma RTM tariff provisions that the Commission would publish in a final rule, the Commission would continue to presume that all of its transmission expenditures are prudent. For utilities without an RTM, the Commission would not presume that capital expenses associated with self-planned projects are prudent. The utility would have to demonstrate prudence and would therefore be unable automatically flow those costs to consumers via existing formula rate processes.

For ITMs, the Commission could similarly order or encourage independent planning entities to adopt them. The Commission could find that an ITM is necessary to address utilities' "opportunities to engage in undue discrimination."[75] The PJM example discussed in response to question 5.b illustrates the urgent need for an independent watchdog. The Commission should be particularly vigilant about undue discrimination in areas such as transmission planning "where the pro forma OATT leaves the transmission provider with significant discretion."[76]

Alternatively, the Commission could add ITMs to the list of required features of a certified RTO. The Commission "has the authority not to accept something which it does not deem an ISO" or RTO.[77] In 2004, when the Commission had found that CAISO's board was not "independent" from market participants under Order No. 2000,[78] the Commission rejected CAISO's attempt to use the "independent entity variation" to comply with the Commission's generator interconnection rules.[79] Here,

[74] *See* Comment of the Harvard Electricity Law Initiative, Docket No. RM21-17 (Oct. 12, 2021) (discussing the Commission's existing prudence policy and showing that a new approach would supplement rather than displace the Commission's existing policy).
[75] Order No. 1000, 136 FERC ¶ 61,051 at PP 59, 78, 147 (2011).
[76] Order No. 890 at P 26.
[77] CAISO v. FERC, 372 F.3d 395, 404 (D.C. Cir. 2004).
[78] *Mirant et al., v. CAISO, et al.,* 100 FERC ¶ 61,059 (2002).
[79] *CAISO, et al.*, 108 FERC ¶ 61,104 (2004).

the Commission could determine that ITM adoption is a necessary component of the being "independent" from market participants. Any RTO/ISO that does not adopt an ITM would cease to be certified as an RTO/ISO.

The Commission could similarly find that retaining an ITM is a required RTO function, akin to market monitoring. In Order No. 2000, the Commission summarized that market monitoring is necessary because the Commission

> is engaged in finding ways to understand market operations in real-time, so that it can identify and react to any problems that are preventing the most efficient operations. It also has a responsibility to protect against anticompetitive effects in electricity markets. If we are to satisfy this goal, we must systematically assess whether our policies and decisions are consistent with this responsibility. Market monitoring is an important tool for ensuring that markets within the region covered by an RTO do not result in wholesale transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power. In addition, market monitoring will provide information regarding opportunities for efficiency improvements.[80]

The Commission could make similar findings today about the relevance of ITMs.

Based on the RTM and ITM functions we have described, the Commission would not be inappropriately delegating its authority to these entities. RTMs and ITMs would gather data, analyze evidence, and scrutinize existing processes. They would provide information to transmission customers, stakeholders, and state regulators and perhaps directly to the Commission in relevant proceedings. These entities would not have any regulatory authority.

h. An RTM should scrutinize all aspects of utility-run transmission planning and development. RTMs should probe cost estimates during the planning stage and track actual expenditures during development. The RTM's data gathering and

[80] Order No. 2000, 89 FERC ¶ 61,285, at p. 189 (1999).

analysis will serve transmission customers and advocates and make it possible for them to viably challenge transmission rates. An ITM would not be charged with reviewing project cost estimates or actual expenditures.

i. No response.

j. No response.

6. In 2006, the Commission determined that "formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs."[81] This Commission finding set up a tradeoff: while cost recovery through formula rates would not be subject to traditional section 205 consumer protections,[82] investments funded through those formula rates would be scrutinized by stakeholders in planning processes and by state regulators in permitting proceedings. Ultimately, consumers might benefit from that compromise.

The evidence shows, however, that formula rates are increasingly used as a vehicle for evading oversight and limiting protests.[83] Many utilities are investing heavily in self-planned projects, and in particular asset replacement projects that are not reviewed in planning processes or state permitting proceedings. Consumers

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[81] Order No. 679, 71 Fed. Reg. 43,294 at P 386 (2006).

[82] Alabama Power Co. v. FERC, 993 F.2d 1557, 1567–68 (D.C. Cir. 1993) ("When the Commission accepts a formula rate as a filed rate, it grants waiver of the filing and notice requirements of section 205," and the public utility's "rates can change repeatedly, without notice to the Commission, provided those changes are consistent with the formula.").

[83] Permissible challenges to formula rate updates are defined when the Commission approves the formula itself. During that proceeding, customers cannot possibly anticipate the challenges they may wish to file decades later. *See, e.g., Ameren Illinois Co.*, 162 FERC ¶ 61,025 at P 28 (2018) (dismissing challenges that "are directed to defined cost categories or specified calculations, i.e., to a fundamental component of the formula rate, not inputs that fall within a defined cost category or are subject to a calculation specified in the rate").

have no notice of these projects and no information about them, even when their costs appear in an annual rate update.[84] Without meaningful disclosure by the utility, customers have no basis for questioning the project, challenging cost recovery, or assessing the utility's performance.[85] Project decisions and costs are essentially unreviewable, and a utility's long-term effectiveness is unknowable.

For example, ISO-NE tracked just $58 million in Asset Condition Projects in 2016. But in the past six years, utilities have placed nearly $3 billion in Asset Condition Projects in service and have proposed or planned an additional $3 billion of these projects.[86] State officials recently complained that these projects are "subjected to materially less regional review and scrutiny" than ISO-NE planned projects and that there is "very little forewarning to states, stakeholders and the paying public as to when these costs will be presented and how significant they will be."[87] Moreover, "there have been instances of unforeseen cost variances where cost estimates for Asset Condition Projects have increased significantly over the course of several years, again with little warning or review."[88] Utility spending on local projects, including asset replacement projects, has also ballooned in MISO, PJM,

[84] Technical Conference Transcript at 26:17–23 (Chair Chandler, Kentucky PSC: "And I can tell you that when it would come to a formula rate filing at FERC for any of our utilities, we would not have any information, even if somebody had – other than the numbers being wrong. . . . unless we're conducting discovery in individual cases we don't have that information."); *id.* at 37:25–38: (Chair Chandler: "So there's an opportunity for quite a bit of transmission or us not to know about it, for us not to see 2 it until it shows up in a rate case."); *id.* at 39:3–9 (Chair Chandler: "They're at a bolt on to projects that might have received their certificate from an affiliate, but that's still 120 million dollars of rate base that has had no oversight anywhere at the state, and the only time it would have oversight would be the rates to recover those investments are coming through the FERC formula transmission rates.").

[85] Technical Conference Transcript at 218:18–23 (Jeff Dennis, Advanced Energy Economy: "Our members have told us that . . . even sophisticated members of our organization folks who are large developers or renewable energy paid transmission customers, have told us that it's very difficult for them to review formula rate filings, and to pursue to the challenge processes that are there.").

[86] NESCOE, Letter to transmission owners Re: Asset Condition Projects and Process (Feb. 8, 2023).

[87] *Id.*

[88] *Id.*

and CAISO,[89] and customers and state regulators have lodged similar complaints about their inability to scrutinize relevant planning decisions and costs.[90]

Formula rates shield utilities from regulation.[91] The benefitting utility escapes the burden of proof it would have to meet in a stated rate case.[92] When formula rates are combined with the Commission's presumption that transmission expenditures are prudent, every single dollar the utility proposes to recover flows through to consumers' bills, provided the utility follows its own formula. This result strips consumers of the protections Congress provided in sections 205 and 206.

Formula rates recently failed spectacularly for FirstEnergy transmission customers. Commission auditors and federal prosecutors revealed that the utility

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[89] In MISO, self-planned projects increased from $1.1 billion per year from 2010–2013 to $2.7 billion per year from 2014–2019. Complaint of Coalition of MISO Transmission Customers, et al., FERC Docket No. EL20-19, at 31–32 (Jan. 21, 2020). Self-planned projects totaled $3.6 billion in 2020 and $3.7 billion in 2022 (We were unable to find MISO's MTEP21 report). "Other-Age and Condition" projects increased steadily from $560 million in 2017 to $1.5 billion in 2022. Meanwhile, regional investment was negligible until MISO approved $10.3 billion of MVP projects in 2021. In PJM, spending on Supplemental projects (local) averaged $1.25 billion from 2005 to 2013, and $3.79 billion from 2014 to 2020. Spending on Baseline regional projects averaged $2.76 billion from 2005 to 2013, and $1.65 billion from 2014 to 2020. The 2005–2019 data is available from PJM Transmission Expansion Advisory Committee, *Project Statistics* (May 12, 2020). 2020 data is from PJM, 2020 Regional Transmission Expansion Plan, at 259 (2020). *See also* Claire Wayner, RMI, "Increased Spending on Transmission in PJM – Is It the Right Type of Line?" (Mar. 20, 2023) (providing stats on disparities between local and regional investments in PJM); Post-Technical Conference Comment of the Organization of PJM States, Docket No. AD22-8 (Mar. 23, 2023). In CAISO, 63 percent of investment by the three largest utilities have been on asset replacement projects. Fifth Meeting of the Joint Federal-State Task Force at 29:15–30:11 (Nov. 15, 2022) (Commissioner Houck of the California Public Utilities Commission).
[90] *See, e.g.,* Technical Conference Transcript at 25:12–27:18 (Chair Chandler, Kentucky PSC); Pre-Technical Conference Statement of Michael Haugh, Office of the Ohio Consumer Counsel, Docket No. AD22-8 (Sep. 16, 2022); Pre-Technical Conference Statement of Randy Howard, Northern California Power Agency, Docket No. AD22-8 (Sep. 22, 2022); Pre-Technical Conference Statement of Michael Cocco, Old Dominion Electric Cooperative, Docket No. AD22-8 (Sep. 22, 2022).
[91] Annual update filings that facilitate cost recovery are not subject to potential suspension or deficiency letters. Alabama Power Co. v. FERC, 993 F.2d 1557, 1567–68 (D.C. Cir. 1993).
[92] *MISO, et al.*, 143 FERC ¶ 61,149 at P 120 n. 200 ("Transmission owners will be required to file their annual updates, but only on an informational basis; they will not be noticed and, absent a formal challenge or complaint, will go into effect without being addressed by Commission order.").

laundered illicit payments through formula transmission rates.[93] FirstEnergy has admitted that its transmission rates recovered payments to a state official "in return for [that official] performing official action in his capacity as PUCO Chairman to further FirstEnergy Corp.'s interests."[94] Commission auditors found that FirstEnergy improperly recorded some of these payments as administrative and general expenses and further fleeced customers by capitalizing some of these illegitimate expenses.[95] To rectify these and other errors, FirstEnergy has reclassified $195 million of certain transmission capital assets to operating expenses and may refund $45 million to transmission customers.[96] While customers may ultimately get their money back, the Commission should nonetheless consider how formula transmission rates facilitated the company's egregious spending. If ordinary formula rate processes could not reveal a utility's illicit profits, how can customers possibly hope to uncover ordinary inefficiency or imprudence?[97]

a. When it developed the MISO formula rate protocols, the Commission correctly recognized that the central challenge in ensuring just and reasonable rates would be counteracting the information asymmetry between transmission owners

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[93] Office of Enforcement, Divisions of Audits and Accounting, Audit Report, Docket No. FA19-1, at pp. 46–51(Feb. 4, 2022).
[94] United States of America v. FirstEnergy Corp, U.S. District Court, Southern District of Ohio, Case No. 21-cr-00086-TSB, Deferred Prosecution Agreement: Attachment A: Statement of Facts, at p. 18 (Jul. 22, 2021).
[95] Office of Enforcement, Divisions of Audits and Accounting, Audit Report, Docket No. FA19-1, at pp. 50–51 (Feb. 4, 2022).
[96] American Transmission Systems Inc., FERC Form 1, End of 2022
[97] In a pre-technical conference statement, Rhode Island PUC Chair Gerwatowski details how regulators accidentally uncovered excess profits of $46 million that a utility recovered via formula rates over a four year period. He summarizes: "It is telling to consider that the windfall profit being generated from the formulaic cost-recovery mechanism used in this case was only discovered because someone in the accounting department of the utility misallocated revenue and expenses to the wrong business unit in a report on distribution earnings. But for that human error, neither the RI PUC nor FERC's processes would have picked up the continuing windfall profits flowing from ratepayers to shareholders." Docket AD22-8 (Oct. 4, 2022).

and customers.[98] The Commission understood that utilities "frequently possess the information necessary for an interested party to succeed in a complaint before the Commission, but retain discretion in providing that information."[99] The existing formula rate protocols are intended to "ensure that a transmission owner's possession of this information does not become, in practice, a means of including inappropriate costs in its annual update and collecting unjustified charges."[100] But the existing protocols have failed to discipline utility spending or motivate utilities to improve their performance.[101]

Existing MISO transparency protocols require utilities to fill in various worksheet templates and justify any "accounting changes."[102] For self-planned projects, the protocols do not require project-specific disclosures or explanations of specific expenditures. The dearth of information makes it all but impossible for customers or stakeholders to expose imprudence or otherwise challenge rates.

We suggest that the Commission require each utility receiving formula transmission rates to make a *prima facie* case in an annual update proceeding that the amount it proposes to recover would result in just and reasonable rates if it were filing stated rates. As discussed above,[103] under the "independent entity variation" policy, the Commission could limit this requirement to self-planned

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[98] *MISO, et al.*, 139 FERC ¶ 61,127 at P 8 (2012) ("The areas of concern are categorized as follows: (1) scope of participation — who can participate in the information exchange; (2) the transparency of the information exchange — what is exchanged; and (3) the ability to challenge the transmission owners' implementation of the formula rate as a result of the information exchange — how the parties may resolve their potential dispute.")
[99] *MISO, et al.*¸ 143 FERC ¶ 61,149 at P 120 (2013).
[100] *Id.*
[101] The evidence speaks for itself. The fact that utilities recovery every dollar they include in an annual update filing that is assigned to the correct account demonstrates that formula rates are not imposing discipline or motivating performance. Utilities face no consequences for cost overruns and their project development decisions are untested.
[102] MISO Open Access Transmission Tariff, Attachment O, Sec. II.D.
[103] *See supra* note 5 and accompanying text and notes 77–79 and accompanying text.

projects. This information transparency requirement would be imposed via the formula rate protocols. To make a *prima facie* showing, the utility would have to file the type of evidence that it would include in a stated rate case, such as testimony and supporting workpapers. Providing stakeholders with this information will allow them to develop probative information and document requests as part of the annual update process. Customers who pay formula rates ought to be entitled to the same information as customers paying stated rates.

This *prima facie* requirement would not interfere with the existing cost recovery process. A utility would continue to recover all costs included an annual update filing, subject to challenges outlined in the protocols. The Commission would review the utility's *prima facie* case only upon receiving a section 206 complaint about the utility's implementation of its formula rate protocols. If the Commission grants the complaint, it could impose more specific transparency requirements as part of the utility's formula rate protocols and would not deny cost recovery. The *prima facie* standard provides the Commission with a benchmark for evaluating whether a utility's annual update filing is sufficiently transparent. It does not add an evidentiary burden for cost recovery.

This transparency enhancement, combined with the creation of utility-specific RTMs and the transparency improvements we discuss in response to questions 1, 2, and 3, will help to counteract the information asymmetry and enable customers to develop viable challenges to utility expenditures. In order for transparency reforms to benefit consumers, the Commission should ensure that formula rate protocols provide customers with sufficient time to review information and issue discovery requests. The protocols should also compel utilities to meaningfully respond to such requests. The Commission could delegate to the Chief Administrative Law Judge authority to resolve discovery disputes on an expedited basis.

7. The Commission should narrow its presumption that transmission expenditures are prudent and set a lower threshold for shifting the burden of proof to the utility. Reforms are necessary because the Commission's current policies fail to hold utilities accountable for cost overruns, imprudent decisions, or other inefficiencies. As discussed in the previous response, formula rates are part of the problem. While formula rates reduce utility incentives to act efficiently, the Commission has understood that this potential downside is "is mitigated by the fact that all charges billed under formula rates are subject to prudence challenges and after-the-fact refund."[104] The Commission's current approach renders this threat toothless and therefore fails to motivate performance or protect consumers.

The Commission reviews prudence of transmission investments only when a party raises "serious doubt" about the prudence of the utility's expenditures. Saddling protesters with the initial burden absolves the utility from having to justify its decisions and actions. As discussed throughout this comment, the Commission does not require utilities to divulge information that might allow customers to expose utility imprudence. Even where a challenger gathers its own evidence about imprudence outside of a Commission proceeding, the Commission does not shift the burden of proof back to the utility.[105] As a result, the Commission never finds imprudence.[106] Instead, it has concluded that every dollar utilities spent

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[104] *Northeast Utils. Serv. Co.*, 62 FERC ¶ 61,294 at p. 62,906 (1993).

[105] *See, e.g., Pacific Gas and Electric Co.*, 173 FERC ¶ 61,045 at PP 165–81 (2020).

[106] In a 2018 filing at this Commission, the California Public Utilities Commission found that because "rate cases usually settle . . . the risk of prudency review is limited, and while serious doubt has been established in a handful of electric transmission cases that have proceeded to hearing, the CPUC could find only one such case in the past 20 years that resulted in findings of imprudence." CPUC, Brief on Exceptions, Docket ER16-2320-002 (Oct. 31, 2018). However, the Commission subsequently reversed its findings, but its order was later vacated by the D.C. Circuit. Newman v. FERC, 27 F.4th 690 (D.C. Cir. 2022).

on transmission — $153 billion from 2014 to 2020 — was prudently incurred.[107] Findings of imprudence are not nearly so rare at state commissions.[108]

The goal of any new policy on transmission expenditure cost recovery should be to provide customers with a meaningful opportunity to challenge transmission rates. Refunding imprudent costs that flowed through a formula rate does not violate the rule against retroactive ratemaking. The Commission has the authority to order refunds of imprudent or incorrectly computed costs passed through a formula rate, regardless of whether those costs were already paid by consumers.[109]

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[107] Edison Electric Institute, Actual and Projected Transmission Investment. Some portion of that amount is regulated by states and not the Commission.

[108] *See, e.g.,* Minnesota Public Utilities Commission, Minutes of Aug. 11, 2022 meeting (summarizing numerous Commission findings of utility imprudence relating to natural gas operations and disallowing nearly $60 million spread across four utilities); Arizona Corporation Commission, Decision No. 78317 (Nov. 9, 2021) (disallowing $215 million due to a finding that the utility's installation of pollution control equipment was imprudent); Public Utility Commission of Oregon, Order No. 20-473 (Dec. 18, 2020) (making findings of imprudence relating to a transmission line and pollution control equipment); Fifth Meeting of the Joint Federal-State Task Force at 48:16–20 (Nov. 15, 2022), (Commissioner Duffley of the NC PUC: "I can think of an instance where there has been a disallowance through that prudency review, through the retail rate case, where the disallowance related to the undergrounding of a portion of a transmission line."). *See also* State Corporation Commission, *Petition of Virginia Electric and Power Co. for a Prudency Determination with respect to the Coastal Virginia Offshore Wind Project*, Case No. PUR-2018-00121 (Nov. 2, 2018) ("The Commission finds — as a purely factual matter based on this record — that the proposed CVOW Project would not be deemed prudent as that term has been applied by this Commission in its long history of public utility regulation or under any common application of the term." The Virginia SCC approved the petition, concluding that "new statutes governing this case subordinate the factual analysis to the legislative intent.").

[109] Northwest Pipeline Corp. v. FERC, 61 F.3d 1479, 1490–91 (10th Cir. 1995); W. Deptford Energy v. FERC, 766 F.3d 10, 22 (explaining that the "'formula itself is the filed rate that provides sufficient notice to ratepayers,'" not the outputs of that formula) (quoting *Pub. Utils. Comm'n v. FERC*, 254 F.3d 250, 254 n.3 (D.C. Cir. 2001)); *Re Public Service Co. of New Hampshire*, 6 FERC ¶ 61,299, at p. 61,711 (1979) ("As we held earlier, this proceeding does not involve issues of retroactive ratemaking; rather, it concerns the use of a fixed formula to pass through to the Company's customers monthly fuel expenses which are not routinely examined in regulatory proceedings."); *Appalachian Power Co.*, 23 FERC ¶ 61,032, at p. 61,088 (1983) ("The energy rate in this docket is a formula rate and the Commission has held in the past that it is not precluded from examining the reasonableness of fuel costs automatically collected under a formula rate."); *N. States Power Co.*, 29 FERC ¶ 61,239 at p. 61,493, n.5 (1984) ("[T]he proposed formula rate comprises an automatic adjustment clause which can be subject to subsequent review or investigation as to the propriety or prudence of the costs flowed through the clause."); *Cajun Elec. Power Coop.*, 52 FERC ¶ 61,059 at pp. 61,255–56 (1990)

a. The Commission has broad discretion to determine which utility expenditures it presumes are prudently incurred and how it identifies imprudence or otherwise denies cost recovery of transmission expenditures. We suggest two reforms to the Commission's current approach: 1) The Commission should narrow the applicability of its prudence presumption; and 2) the Commission should outline how it will evaluate cost recovery challenges.

The Commission has said that administrative convenience justifies its current policy of presuming that all transmission expenditures are prudent,[110] but that goal has no connection to the FPA's mandate that all rates be just and reasonable. In other contexts, the Commission presumes rates are just and reasonable when there is a substantive basis for doing so.[111] The Commission should follow this approach

("The Commission's authority to order refunds of amounts flowed through the fuel adjustment clause is well settled."); *North Carolina Electric Membership Corp. v. Carolina Power & Light*, 57 FERC ¶ 61,332, at p. 62,065 (1991) (rejecting the utility's efforts to limit the period of review to the prior 12 months); *Yankee Atomic Electric*, 60 FERC ¶ 61,316, at p. 62,096–97 (1992) (allowing review of potentially imprudent costs charged to customers in prior-year formula rates); *DTE Energy Trading v. MISO*, 111 FERC ¶ 61,062, at P 28 (2005); *Delmarva Power & Light*, 145 FERC ¶ 61,055 at P 23 (2013); *Entergy Services*, 145 FERC ¶ 61,049 at P 10 (2013) ("The Commission has also previously noted its authority to order refunds for imprudent costs charged to customers through an existing formula rate. As with challenges premised upon misapplication of formula rates, the Commission has rejected attempts to limit the timeframe for prudence inquiries."); *Puget Sound Energy*, 165 FERC ¶ 61,209 at P 19 (2018) ("The Commission's longstanding precedent allows participants to challenge formula rate input or implementation errors whenever the participants discover them, and to recover refunds for past periods in which a utility has misapplied a formula rate or otherwise charged rates that are contrary to the filed rate.").

[110] *Iroquois Gas Transmission System,* 87 FERC ¶ 61,295, at p. 62,168 (1999) (quoting *Minnesota Power & Light Co.*, 11 FERC ¶ 61,312, at pp. 61,644–45 (1980) (stating that FERC adopted this policy as "a matter of procedural practice to ensure that rate cases are manageable").

[111] *See, e.g.* Morgan Stanley Capital Group v. Public Util. Dist. No. 1 of Snohomish County, 554 U.S. 527, 530 (2008) (summarizing that under the *Mobile-Sierra* cases, the Commission "presume[s] that the electricity rate set out in a freely negotiated wholesale-energy contract meets the just and reasonable requirement"); Montana Consumer Counsel v. FERC, 659 F.3d 910, 914–17 (9th Cir. 2011) (explaining that the Commission presumes that a seller's market-based rates are just and reasonable when it finds that the seller lacks market power); *Allegheny Power Supply Company*, 108 FERC ¶ 61,082 at P 18 (2004) (explaining that the Commission presumes that the rate in a wholesale contract between affiliates is just and reasonable when there is evidence that "the

by issuing a supplemental prudence policy that delineates criteria for applying a default prudence presumption to certain capital expenditures.[112]

In Docket No. RM21-17, we suggested that the Commission distinguish between self-planned projects and projects planned by an independent entity and presume that only capital expenses associated with independently planned projects are prudent.[113] In that filing, we summarized Commission findings about profit-maximizing, self-interested monopolist transmission owners that demonstrate a need for reviewing self-planned capital expenses.[114] Based on these findings, the

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proposed sale was a result of direct head-to-head competition between affiliated and competing unaffiliated suppliers.").

[112] When the Commission formally announced its blanket prudence presumption, it specified that in general "utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent *unless the Commission's filing requirements, policy or precedent otherwise require*." *Minnesota Power & Light Co.*, 11 FERC ¶ 61,312, at pp. 61,644–45 (1980) (emphasis added). Contemporaneous Commission orders illustrate that Commission policies or precedents did indeed require utilities to demonstrate prudence in particular circumstances. *See, e.g., Re Southern California Edison Co.*, 8 FERC ¶ 61,198, at p. 61,679 (1979) (stating that "the company must prove that the abandonment was prudent"); *Louisiana Power and Light Co.*, 9 FERC ¶ 63,054, at p. 65,183 (1979) (ALJ observing that "the Commission requires that a company requesting the inclusion of CWIP in rate base demonstrate that the construction which resulted in severe financial difficulty was, in fact, a prudent investment prudently managed"). A supplemental prudence policy would not reverse the Commission's general approach to prudence. Rather, a new policy would be a "filing requirement[], policy, or precedent [that] otherwise require[s]" the utility to demonstrate prudence. *Iroquois Gas Transmission System*, 87 FERC ¶ 61,295, at p. 62,169 (1999) (noting that under *Minnesota Power & Light Co.* "the Commission itself has the option of requiring the utility to demonstrate the prudence of an expenditure in the order setting the matter for hearing or in a later order").

[113] Initial Comment of the Harvard Electricity Law Initiative, Docket No. RM21-17 (Oct. 12, 2021).

[114] The Commission has repeatedly found that utilities act on their incentives and opportunities to increase their profits at the expense of captive ratepayers. *See, e.g., Boston Edison Co. Re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382, at p. 62,168 (1991) (explaining that "where a traditional utility is buying from an affiliate not subject to cost-of-service regulation, the buyer has an incentive to favor its affiliate even if the affiliate is not the least-cost supplier, because the higher profits can accrue to the [buyer's] shareholders"); Proposed Rule, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities, 60 Fed. Reg. 17,662, at p. 17,665 (Apr. 7, 1995) ("as profit maximizing firms, [utilities] . . . will deny consumers the substantial benefits of lower electricity prices"); Order No. 888, 61 Fed. Reg. 21,540 at p. 21,567 (May 10, 1996) ("It is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest

Commission should presume that utilities prioritize projects that provide shareholders with riskless returns over investments that may yield greater consumer benefits. In our earlier filing, we suggested criteria that the Commission could apply to narrow the scope of its prudence review.

As question 11.b suggests, the Commission could incorporate state permitting proceedings into this proposal. For instance, the Commission could presume prudence where the self-planned project was subject to a state permitting proceeding where utility regulators reviewed cost and need issued an order approving the project. In response to question 11.b, we discuss features of a "robust" permitting process in greater detail.

But we believe that state permitting processes have only limited value to the Commission. By their nature, state reviews are typically focused on in-state costs and benefits and may overlook the regional context.[115] In some states, permitting boards are not primarily utility regulators[116] and may not consider need or costs,[117] and may therefore be ill-equipped to evaluate alternatives. Even if state-level review is conducted by utility regulators and results in an order approving the project, state review should not entirely immunize expenditures from review. Once it has issued a certificate of public convenience and necessity (CPCN) or similar permit, a state siting authority has no ability to prevent excessive project costs from

to the detriment of others . . ."); Order No. 1000 at P 256 ("it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs").

[115] *See, e.g.,* Technical Conference Transcript at 260:7–261:13 (Maine PUC Chair Bartlett: "If you think about a region like New England, we have six states. And a few projects will come to Maine for CPCN, but I'm making that decision without being able to put it into the regional context."

[116] *See, e.g.,* MASS. GEN. LAWS Ch. 164 § 69H (creating an Energy Facilities Siting Board and including two state utility regulators among its nine members).

[117] *See, e.g.,* New Hampshire RSA 162:H-16 (listing factors that guide the Site Evaluation Committee's decisions).

flowing to consumer bills.[118] Despite our reservations about relying on state permitting proceedings to determine prudence of self-planned projects, our proposed supplementary prudence policy defers to "robust" state permitting processes that approve low-voltage projects.

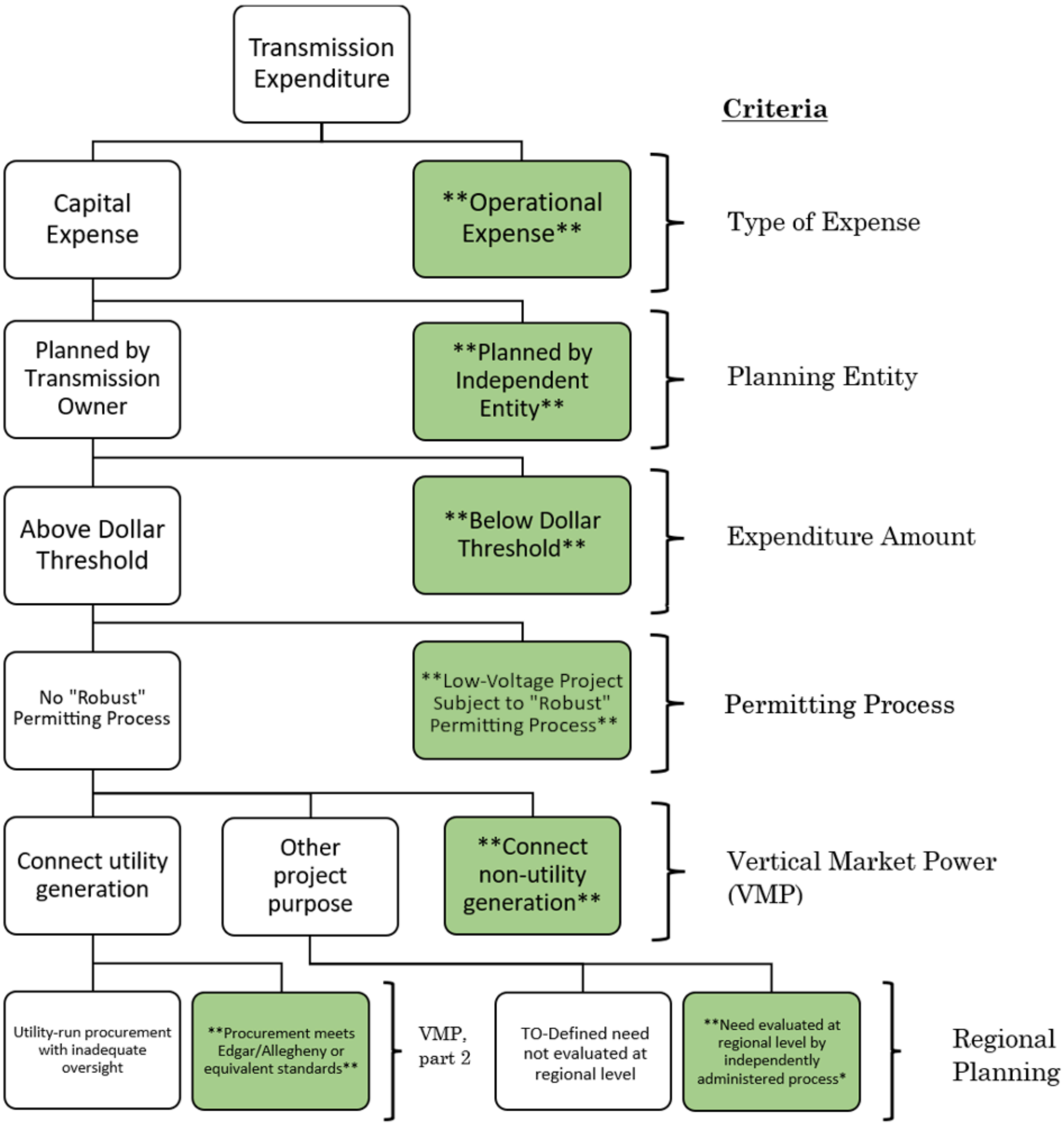
On the next page, we illustrate this supplementary prudence policy that would narrow the prudence presumption.[119]

[118] *See, e.g.,* Technical Conference Transcript at 260:7–261:13 (Maine PUC Chair Bartlett: "It's also not a substitute for following through afterwards. When we have a CPCN, once we issue that certificate our job is done, and then the costs go up . . . and we're not looking, judging prudency at that point. While on the distribution side when we're doing rate cases we were always looking at the prudency of investments that have been made, and that includes the management of those projects in development.").

[119] For further explanations, *see* Pre-Technical Conference Statement of Ari Peskoe, Docket No. AD22-8 (Sep. 16, 2022).

Supplementary Prudence Policy

** Denotes** that the Commission would presume the expense is prudent.



"Robust" permitting processes include review of cost and need and culminate with an order by utility regulators approving the project. See response to question 11.b.

Exceptions:

1. When a project is significantly over-budget (25 percent might be a reasonable threshold), subsequent capital expenses would not be presumed prudent.
2. If a utility adopts an RTM, all of its capital expenses would be presumed prudently incurred (see responses to question 5).

Regardless of whether the Commission narrows the scope of its prudence presumption, it should develop a new approach for reviewing challenges to transmission expenditures. As a practical matter, current Commission policy is to allow the utility to recover every dollar it spends. The Commission does not grant complaints challenging utility expenses as imprudent, inefficient, or unnecessary; launch its own investigations of utility expenses; or even shift the burden of proof to utilities in section 205 stated rate cases.[120] As discussed throughout this comment, customers often lack information needed to viably challenge utility spending. But even if the Commission addresses the information deficit, customers will continue to be vulnerable to utility exploitation in the absence of a new approach to cost recovery challenges. The Commission's unfailing deference to utilities is not motivating utility performance or protecting consumers.[121]

The impossibility of challenging prudence, efficiency, or necessity undercuts a core assumption of the Commission's formula rate regime. In initiating its investigation into the MISO utilities' formula rate protocols, the Commission found that the then-existing "protocols do not provide interested parties the information necessary to understand and evaluate the implementation of the formula rate for either the correctness of inputs and calculations or t*he reasonableness and prudence of the costs to be recovered in the formula rate* . . . ."[122] The inability to viably challenge prudence, efficiency, or necessity threatens the justness and reasonableness of transmission rates.

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[120] *See, e.g., Pacific Gas and Electric Co.*, 173 FERC ¶ 61,045 at PP 165–181 (2020).
[121] As noted throughout this comment, the Commission never finds imprudence. It simply cannot be the case that every penny spent by utilities was prudently incurred. A perfect record of performance is wildly improbable. The more likely explanation is that the Commission policies make it all but impossible for customers to successfully challenge utility expenditures.
[122] *MISO, et al.*, 139 FERC ¶ 61,127 at P 15 (2012); *id.* at P 16.

The Commission has broad authority to disallow recovery of costs through transmission rates.[123] It may prevent utilities from including in their rate base project costs that are not "used and useful."[124] The Commission may also disallow recovery of costs found to be imprudent when those expenditures are evaluated with the benefit of hindsight.[125] The Commission also has discretion to impose various cost sharing mechanisms, such as allowing cost recovery but disallowing a rate of return on certain expenses or splitting costs of projects between shareholders and ratepayers.[126] As applied to formula transmission rates, the Commission has authority to completely or partially disallow recovery of project costs and order

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[123] *See generally*, FPC v. Hope Natural Gas Co., CITE; Washington Gas Light Co. v. Baker*,* 188 F.2d 11, 14 (D.C. Cir. 1950) ("So long as the public interest—i.e., that of investors and consumers—is safeguarded, it seems that the Commission may formulate its own standards. . . . Thus, there is a zone of reasonableness within which rates may properly fall. It is bounded at one end by the investor interest against confiscation and at the other by the consumer interest against exorbitant rates."); Midwestern Gas Transmission Co. v. FPC, 388 F.2d 444, 448 (7th Cir. 1968) ("[I]t has long been recognized that establishment of public utility charges involves the assessment of costs for a public service. Basic to the purpose of the Natural Gas Act is a design of regulation concerned with final adoption of rate charges fairly intended to protect the public interest. . . . If [management] policies do not fairly indicate a reasonable and prudent business expense, which the consuming public may reasonably be required to bear, . . . then federal regulatory intervention is required."); Cities Service Gas Co. v. FPC*,* 424 F.2d 411, 417 (10th Cir. 1969) ("A regulated utility may not impose unnecessary costs upon its consumers.").

[124] Duquesne Light Co. v. Barasch, 488 U.S. 299, 308–09 (1989) ("To the extent utilities' investments turn out to be bad ones (such as plants that are canceled and so never used and useful to the public), the utilities suffer because the investments have no fair value, and so justify no return."); Jersey Central Power & Light Co. v. FERC, 810 F.2d 1168, 1184 (D.C. Cir. 1987) (noting that the Commission had excluded unamortized costs of cancelled plants in several proceedings, a result generally upheld in NEPCO Municipal Rate Comm. v. FERC*,* 668 F.2d 1327 (D.C. Cir. 1981)).

[125] Duquesne Light Co., 488 U.S. at 309, 315 (rejecting the electric utility industry's argument that the Court adopt the "prudent investment rule" as the Constitutional standard, whereby "the utility [would be] compensated for all prudent investments at their actual cost when made . . . irrespective of whether individual investments are deemed necessary or beneficial in hindsight."

[126] *See, e.g.,* NEPCO Municipal Rate Committee v. FERC, 668 F.2d 1327 (D.C. Cir. 1981) (upholding in part a Commission order that excluded expenditures for cancelled power plants from rate base but allowed for their recovery over time and finding that the Commission's approach "struck a reasonable balance between the interests of investors and ratepayers"); *New England Power Co.*, 42 FERC ¶ 61,016, *order on reh'g*, 43 FERC ¶ 61,285 (1988) (approving an "explicit 50-50 sharing of the loss between investors and ratepayers" for cancelled plants); *Public Service Co. of New Mexico*, 75 FERC 61,266 (1996) (applying the 50-50 split to a cancelled transmission project).

refunds of costs already recovered from ratepayers through previous annual update filings. However, we are not aware of the Commission ever using this authority. The Commission's current approach to transmission expenditures amounts to "pass-through regulation."[127]

The lack of oversight benefits utility shareholders while harming consumers twice over. First, automatic pass-through of costs does not incentivize efficiency. To the contrary, it sends a clear message to utilities that they will face no penalty for excessive costs or unneeded projects and should prioritize shareholder returns over ratepayer benefits. As the New York Public Service Commission put it: "a utility's motivation to act prudently arises from the prospect that imprudent costs may be disallowed."[128] At the Technical conference, Rhode Island PUC Chair Gerwatowski, a 28-year veteran of an interstate utility company, made a similar point:

> I'm certain that utilities . . . will tell you with sincerity that they have procurement programs, they do variances, they look at alternatives, and they care about costs. But I can say that if you look past in the history and you never see a disallowance, and you never see anything that's been challenged . . . Then the utility is going to lose sight of that, and it's not going to be a priority, and they're not going to be thinking about it, and the engineer is not going to be thinking about it, the financial folks aren't going to be thinking about it because there's no risk.[129]

Second, the Commission's current approach to assessing prudence prevents transmission customers and ratepayer advocates from successfully challenging utility expenditures. The Commission's policies have all but eliminated this foundational element of utility regulation. With a utility's cost recovery guaranteed,

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[127] Paul L. Joskow, MIT Center for Energy and Environmental Policy Research, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, p. 13 (Mar. 2019).
[128] *Re Long Island Lighting Co., et al.*, Case 27563, Opinion No. 85-23, 71 P.U.R.4th 262 (Nov. 16, 1985); *id.* ("The disallowance of imprudently incurred costs is fundamental to the law of utility regulation . . . and we regularly deny recovery of costs that have resulted from imprudent actions.").
[129] Technical Conference Transcript at 211:1–23.

so long as it follows its own formula, captive ratepayers have no incentive to participate in rate cases or engage in regulatory processes. By silencing challengers, Commission policies reinforce the utility's monopoly position and embolden it to pursue projects that enrich shareholders regardless of customer benefits.

The Commission's "reasonable man" prudence test is ineffective and should be discarded.[130] Earlier precedent provides a starting point for a new approach:

> Just as there are areas where regulation should not interfere, so are there areas where the Commission must apply its judgment in the performance of its obligation to protect the public interest. It is here that regulation must appraise and be prepared to guide and restrain management's judgment—in the same sense that competition in the free market area guides and restrains managerial judgments in business not subject to regulation.
>
> A wholly valid argument is made that regulation must not engage in a reconsideration of every operating decision made by management and that the substitution of the regulatory agency's judgment for that of management on every disputed operating item can only stultify the normal performance of the management function. We agree. Regulation must act with restraint in seeking to substitute the regulator's views for that of management on matters of operational policy. But regulation is reduced to an exercise in futility if it is barred or bars itself from a review of management claims for the recovery of costs running into millions of dollars solely because 'management has exercised its judgment.'[131]

This rationale justifies the approach we outlined above. The Commission would not "reconsider[] every operating decision," but where the utility seeks "recovery of costs running into millions of dollars" for utility-planned projects, the Commission should exercise its oversight responsibilities. Commission precedent also informs the standard of review. The Commission has summarized that "adjectives used in the cases in discussing imprudent costs [include] 'extravagant,' 'unnecessary,'

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[130] *New England Power Co.*, 31 FERC ¶ 61,047, at p. 61,084 (1985).
[131] *Re Midwestern Gas Transmission*, 36 FPC 61, at p. 71 (1966) (citing Acker v. U.S., 298 U.S. 426, 430–31 (1935)).

'inefficient,' [and] 'improvident.'"[132] Federal courts have used similar terms.[133] State regulators have provided additional tests for denying cost recovery:

- Evaluation of utility expenditures should consider "reasonable and appropriate business standards" and "minimization of costs to ratepayers, consistent with safety, reliability and quality assurance."[134]
- Expenses should be disallowed when "managerial discretion has been abused," "action taken has been arbitrary or inimical to the public interest," or "there has been economic waste."[135]
- "Expenditures found excessive, unaccounted for, or caused by lack of proper foresight should be deemed imprudent and disallowed."[136]
- Expenditures caused by "inadequate and unreasonable management practices," such as inadequate procedures to guide employee actions and failure to correct persistent employee errors, were imprudent.[137]
- A utility must "reasonably consider alternatives" in order to demonstrate that its investment is "cost-effective or the lowest cost alternative."[138]

[132] New England Power Company, Opinion No. 231, 31 FERC ¶ 61,047, at p. 61,084 (1985).
[133] Acker v. U.S., 298 U.S. 426, 431 (1935) ("Regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs . . ."); Trans World Airlines v. CAB, 385 F.2d 648, 656 (D.C. Cir. 1967) (affirming an order where the regulator "determined that the evidence affirmatively showed petitioner's inefficiency and imprudent management"); City of Anaheim, et al., v. FERC, 669 F.2d 799, 809 (D.C. Cir. 1981) ("The [prudence] presumption does not survive 'a showing of inefficiency or improvidence.'") (citation omitted).
[134] Illinois Commerce Commission, *Re Central Illinois Light Co.*, Case No. 90-0127, 124 P.U.R.4th 498 (Aug. 2, 1991).
[135] Pacific Power & Light Co. v. PSC of Wyoming, 677 P.2d 799, 805–06 (WY 1984).
[136] Public Utility Commission of Oregon, *In the Matter of PacifiCorp Request for a General Rate Revision*, Order No. 20-473 (Dec. 18, 2020).
[137] Entergy Gulf States v. Louisiana Public Service Commission, 726 So.2d 870, 880 (LA 1999).
[138] Public Service Co. of New Mexico v. New Mexico Public Regulation Comm'n, 444 F.3d 460, 472 (N.M. 2019)

- "A thorough review of alternatives is expected for large projects and [a utility] risks recovery when alternatives are not fully analyzed."[139]
- A utility "has a duty to monitor the economics of its investments . . . until the project is completed . . . and alter . . . its course for a project if doing so makes sense economically and is in the public interest even if altering the course may not be as advantageous to its shareholders as completing the project would be."[140]

To craft a new approach to reviewing utility capital expenditures, the Commission could look beyond these traditional definitions of imprudence. Imprudent is not a talismanic word that encapsulates the full scope of the Commission's authority to deny recovery or inclusion in rate base. In general, the Commission is "free, within limitations imposed by pertinent constitutional and statutory commands, to devise methods of regulation capable of equitably reconciling diverse and conflicting interests."[141] An administrative law judge at this Commission explained that

> A regulated public utility does not act imprudently merely because it fails to act in the best interests of its ratepayers in circumstances where those interests conflict with the corporate interests of the utility and its stockholders. The task of protecting the interests of the ratepayers in those circumstances is a burden that rests upon the regulatory agencies that are authorized by law to regulate the rates and practices of the utility. *There is, in short, a category of utility management actions which fall outside the sphere of imprudent activity, with its connotations of extravagance and waste of corporate resources but that are nevertheless subject to the agency's power to redress the balance of economic burdens and benefits when necessary to protect the ratepayers.* That is the fundamental mission of this

[139] New Hampshire Public Utilities Commission, *Public Service Company of New Hampshire*, Order No. 26,504, DE 19-057 (Jul. 30, 2021).
[140] Arizona Corporation Commission, Decision No. 78317 (Nov. 9, 2021).
[141] In re Permian Basin Area Rate Cases, 390 U.S. 474, 767 (1968).

> Commission, which has itself recently reminded us that, at root, it is primarily a consumer-protection agency.[142]

In assessing utility capital expenditures, relevant factors could include whether: 1) the utility evaluated alternative expenditures, including maintenance in existing facilities and investments in grid-enhancing technologies and non-transmission alternatives; 2) the project expenditures exceeded the utility's initial budget; and 3) the project's anticipated benefits for ratepayers exceed its costs.[143] The Commission might also consider a utility's investment patterns. Where a utility suddenly embarks on a large-scale asset replacement campaign, the Commission ought to be open to consumer complaints and require the utility to justify its increased capital spending. The Commission could consider other potentially self-interested behavior, such as whether a utility is "performing less necessary capital work on which it earns a return rather than maintenance work on which it does not."[144] Heightened scrutiny is warranted when customers raise concerns that the utility may be exploiting its monopoly position.

Where there is no independent planning entity, the Commission could also consider the mix of project types that the utility develops, such as replacement, local

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[142] *Arizona Pub. Serv. Co.*, 22 FERC ¶ 63,062, 65,231 (1983) (emphasis added). The Commission affirmed this part of the ALJ's decision, 25 FERC ¶ 61,092, which was subsequently upheld by a federal appeals court. Papago Tribal Utility Authority v. FERC, 773 F.2d 1056 (9th Cir. 1985).
[143] *BP Pipelines (Alaska)*, *et al.* 153 FERC ¶ 61,233 at P 12 (2015) (A prudent utility must "conduct[] reasonable evaluation of the costs and benefits prior to incurring a financial commitment."). In that proceeding, a Commission ALJ put forward a three-part prudence test: "A reasonable manager should ensure that expenditures are prudently incurred at sanction by: (1) adequately researching the project before sanctioning it; (2) estimating project costs with reasonable accuracy and weighing them against project benefits to the ratepayers; and (3) adequately considering alternatives to the project." *BP Pipelines (Alaska)*, *et al.* 146 FERC ¶ 63,019 at P 122 (2014).
[144] Katharine M. Mapes, Lauren L. Springett, and Anree G. Little, Retooling Ratemaking: Addressing Perverse Incentives in Wholesale Transmission Rates, 42 ENERGY L. J. 339, 368 (2021) ("When there is long-standing evidence that utilities have neglected maintenance for years leading to more expensive maintenance later on, ratepayers could object. Likewise, if utilities are performing less necessary capital work on which they earn a return rather than maintenance work on which they don't, ratepayers again would have recourse.").

expansion, regional, and interregional. The Commission has a duty to encourage regionalization,[145] and has repeatedly recognized the value of regional transmission to consumers.[146] Utilities that plan all of their transmission capital expenses should be held accountable for the full range of their investment choices and be required to justify their decisions.

The Commission's task here is not to formulate an exact standard for reviewing utility transmission expenditures. Determining whether particular expenditures are extravagant, unnecessary, inefficient, or improvident or whether they unjustly enrich shareholders will be a fact-based inquiry. In trying to find a balance between investor and consumer interests, the Commission should not let the perfect be the enemy of the good. In denying cost recovery, it is inevitable that the Commission will be under-inclusive in some cases and over-inclusive in others. But that imprecision is not a legal problem. The FPA provides that the Commission findings supported by substantial evidence "shall be conclusive,"[147] and Courts defer to the Commission's factual findings.[148] "[T]hose who would overturn the Commission's judgment undertake 'the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable *in its consequences*.'"[149]

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[145] 16 U.S.C. 216a(a); Jersey Central Power & Light v. FPC, 319 U.S. 61, 68 n.7 (quoting S. Rep. No. 621, 74th Cong., 1st Sess., p. 17) ("The new part 2 of the Federal Water Power Act seeks to bring about the regional coordination of the operating facilities of the interstate utilities along the same lines within which the financial and managerial control is limited by title I of the bill."). *See also* FPC, 1964 NATIONAL POWER SURVEY (1964) (The Report provided "an outline for the coordinated growth of the industry" in order to unlock the "enormous potential benefits of a truly integrated system of power supply." The "heart of the report" describes an illustrative plan for "progressive enlargement of geographical areas of coordination.").

[146] *See, e.g.,* FERC, Policy Statement Regarding Regional Transmission Groups, 58 Fed. Reg. 41,626, (Aug. 5, 1993); Order No. 890 at PP 84, 422–25, 524.

[147] 16 U.S.C. 825l(b).

[148] *See, e.g.,* Morgan Stanley Capital Grp., v. Pub. Util. Dist. No. 1 of Snohomish Cty., 554 U.S. 527, 532 (2008) (citing FPC v. Texaco Inc., 417 U.S. 380, 389 (1974); Permian Basin Area Rate Cases, 390 U.S. at 767 (1968)).

[149] Permian Basin Area Rate Cases, 390 U.S. at 767 (quoting Hope Nat. Gas Co., 320 U.S. at 602) (emphasis added).

Courts may nonetheless find Commission action arbitrary and capricious or that it departs from existing regulatory principles. In the past several months, the D.C. Circuit has remanded orders on transmission ROEs,[150] transmission cost allocation,[151] transmission interconnection,[152] and transmission rates and service[153] for these reasons. All that is to say, these types of legal risks already impair Commission transmission orders. Courts invariably shape Commission transmission regulation, and cost recovery challenges would be no different.

Reviewing utility transmission expenditures will require the Commission to make difficult factual and economic judgements. Because many projects that might be subject to review or challenge are paid for solely by captive ratepayers and located within a utility's state-granted service territory, it is reasonable for the Commission to collaborate with state regulators on these inquiries. We suggest that the Commission provide state regulators with a pathway for creating Joint Boards that would adjudicate whether expenditures are recoverable and whether associated transmission rate increases are just and reasonable. This approach is permissible under long-standing rules that allow the Commission to "define the 'force and effect'" of a Joint Board's action.[154] Here, the Commission would empower

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[150] MISO Transmission Owners v. FERC, 45 F.4th 248 (D.C. Cir. 2022) (finding the Commission's ROE methodology arbitrary and capricious).
[151] Consolidated Edison Co. of New York v. FERC, 45 F.4th 265 (D.C. Cir. 2022) (finding that a PJM cost allocation methodology departed from the cost-causation principle and therefore cannot be considered just and reasonable).
[152] American Clean Power Ass'n. v. FERC, 54 F.4th 722 (D.C. Cir. 2022) (holding that the Commission's "decision to grant unilateral funding authority to all transmission owners failed to satisfy the Administrative Procedure Act's arbitrary-and-capricious standard").
[153] Kentucky Municipal Energy Agency v. FERC, 45 4th 162 (D.C. Cir. 2022) (finding that it was arbitrary and capricious for the Commission "to ignore the effect pancaking would have on rates" when it authorized utilities to end de-pancaking).
[154] 18 CFR § 385.1304(b). The Commission should disclaim its erroneous understanding that Congress intended the Commission to invoke Joint Boards only in "unusual cases," 18 CFR § 385.1304(a) as "not supported by the statute or the legislative history." Frank P. Darr, "A Critical Analysis of Joint Board Policy at the Federal Energy Regulatory Commission," 30 SAN DIEGO L. REV. 485, 496 (1991). The Senate Report explains that FPA section 209(a) "is designed to permit

Joint Boards, consisting of the Commission and state regulators, to issue section 205 orders. The Commission could convene separate Joint Boards for each utility filing or designate one Joint Board to adjudicate rate cases filed by all utilities in that state. RTMs (discussed above in response to question 5) could provide relevant evidence in these proceedings.

8. In response to question 1.a, we suggested that the Commission require utilities to file their local planning criteria under section 205. Eventually, the Commission might set minimum standards for planning criteria. We agree with the premise of this question that those standards could affect the scope of the Commission's prudence presumption.

<u>Federal and State Regulation of Transmission Facilities</u>

9. While states authorize some transmission investments on a project-by-project basis and may consider forecasted costs and benefits in exercising that authority, only the Commission has jurisdiction over transmission *rates* and a duty to ensure that those rates are just and reasonable. A state-by-state approach to transmission oversight does not capture the spillover effects of transmission networks.[155] While states face legal and practical obstacles to overseeing interstate networks, Congress charged this Commission with a "duty . . . to promote and encourage" regional and

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decentralized administration under the general supervision of the Commission by individuals who are acquainted with the situation and the problems of the locality affected by the particular proceeding." *Id.* at 492 (quoting S. Rep. No. 621, 74th Cong., 1st Sess. 52 (1935)).

[155] Fifth Meeting of the Joint Federal-State Task Force, Nov. 15, 2022, at 40:8–11 (Chair Stanek, Maryland PSC: "I would argue that State Commissions, who are perpetually resource constrained, should not necessarily be in the business of conducting transmission studies on the bulk power system.").

interregional coordination.[156] Rate regulation is the Commission's primary tool for accomplishing Congress's mission.

The October technical conference highlighted that many asset replacement and lower voltage projects are not subject to state permitting requirements.[157] As described above, Commission oversight is indirect, as it relies on stakeholders in utility-administered, Commission-approved processes to raise objections to utility plans and rates. This indirect oversight is ineffective, in part because the lack of information disclosures and the Commission's standard of review leave transmission customers with no hope of successfully challenging utility expenditures or meaningfully affecting utility planning. This regulatory construct incentivizes utilities to invest in small-scale projects within their service territories to avoid oversight and the complexities of regional planning and multi-state siting. Higher profits for local projects fuel utilities' local bias. As noted above, utility earnings are higher on a per-dollar basis for local investments as compared to regional projects.[158]

In our responses to questions 1 through 7, we suggested reforms to local planning, formula rates, and Commission review of transmission expenditures that are aimed at protecting consumers from inefficient investments. Our responses suggest that the Commission account for state oversight and include state

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[156] 16 U.S.C. 824a(a).

[157] *See, e.g.,* Technical Conference Transcript at 88:17–22 (James McLawhorn, Director, Energy Division, North Carolina Utilities Commission: "A certificate is only required for new construction, and in North Carolina it's for 161 kV and above. We don't have any 161, so it's basically 230 and 500, and there's not a lot of that that is built, so we have a lot of 115, and we find out about it when, as we said this morning, when it shows up in rates."); *see also* Fifth Meeting of the Joint Federal-State Task Force, at 24:5–25:22 (Nov. 15, 2022) (Chair Dutriuille of the PA PUC explaining that new projects under 100 kV and replacement projects are not adjudicated and that the PUC is "seeing more and more of these types of projects").

[158] Claire Wayner, RMI, "Increased Spending on Transmission in PJM – Is It the Right Type of Line?" (Mar. 20, 2023).

regulators in certain transmission rate decisions. In response to question 7, we proposed that the Commission narrow the scope of its prudence presumption and provided several criteria that would determine whether particular capital expenses are presumed prudently incurred. We suggested that the Commission presume prudence of capital expenses of low-voltage projects subject to a "robust" permitting proceeding, as we discuss further in response to question 11. However, if capital expenditures exceed the initial estimate provided in the state permitting process, the Commission would not presume prudence. We also suggested that the Commission allow state regulators to petition the Commission to set up a Joint Board that would decide cost recovery challenges and related rate matters.

Taken together, the regulatory gaps discussed at the technical conference allow transmission costs to automatically flow to consumer rates. The central problem is that utilities are not being held accountable for transmission costs. As we have discussed throughout this comment, the Commission's principal goal in this proceeding should be to hold utilities accountable for transmission decisions and costs. It may be able to do so without necessarily filling every gap.

10. As the question notes, asset replacement projects typically do not need state siting permission and are not reviewed in Order No. 890 local planning processes. Transmission customers may not find out about these projects until utilities release formula rate annual updates, but those filings may not include project-specific details. It may be impossible for customers or state regulators to track expenditures on individual projects. As discussed throughout this comment, the lack of transparency neutralizes regulatory oversight. Utilities are not held accountable for their decisions or expenditures, and customers lack sufficient information to viably challenge any aspect of these projects. In response to questions 1 through 7, we

suggest numerous reforms aimed at dramatically enhancing transparency and enabling customers to challenge utility decisions and expenditures.

Many lower voltage local expansion projects are on similar footing. Some states do not require siting permission,[159] and while these projects are subject Order No. 890, the record shows that these processes are insufficient to discipline utility decisions. Commission policies make it all but impossible for customers to viably challenge utility decisions and expenditures associated with these projects. Even where lower voltage projects are approved by a state authority, the Commission should only give limited weight to those decisions. States cannot review expenditures and deny cost recovery if the project costs exceed the budget, and the state process may not be situated to evaluate alternatives, such as regional options. As Maine PUC Chair Bartlett put it, once a utility applies for siting permission, "at that point the project is baked. We can try to look at alternatives, but [ ] the project is just pretty far along at that point, so even a very robust process in my view is not a substitute for really engaging early on in the planning process. It's also not a substitute for following through afterwards."[160]

11. The Commission has jurisdiction over all transmission rates.[161] As we mention in response to question 7, a state-by-state approach to transmission regulation is practically and legally unworkable. That said, we recognize that states permit transmission construction and that some states only permit projects that it finds are needed to provide reliable and affordable service to local consumers. Such determinations can be useful to the Commission in limited circumstances.

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[159] *See supra* note 157.

[160] Technical Conference Transcript at 260:7–261:13.

[161] New York v. FERC, 535 U.S. 1, 17 (2002) ("There is no language in the statute limiting FERC's *transmission* jurisdiction to the wholesale market, although the statute does limit FERC's *sale* jurisdiction to that at wholesale.") (emphasis in original).

At the October Technical Conference, Maine PUC Chair Bartlett explained that state siting processes have a limited scope and should not be relied on to guard against inefficient transmission investment. He described

> limitations [ ] of the state process or the CPCN process . . . If you think about a region like New England, we have six states. And a few projects will come to Maine for CPCN, but I'm making that decision without being able to put it into the regional context . . . and you know, at that point the project is baked. We can try to look at alternatives, but we don't -- the project is just pretty far along at that point, so even a very robust process in my view is not a substitute for really engaging early on in the planning process. It's also not a substitute for following through afterwards. When we have a CPCN, once we issue that certificate our job is done, and then the costs go up . . . and we're not looking, judging prudency at that point. While on the distribution side when we're doing rate cases we were always looking at the prudency of investments that have been made, and that includes the management of those projects in development. . . . So both in terms of not being present at the planning stage, and not being present at sort of after the CPCN process, on the cost management side, I think is a real shortcoming, even in the most robust CPCN process.[162]

Chair Stanek of the Maryland Commission echoed this description, characterizing the state permitting process as "sort of like the pitstop" between planning and cost recovery and expressing concern that the "process may not be sustainable for the long-term because in PJM currently the supplemental projects currently represent the majority of all projects."[163]

a. In some states, permitting decisions are made by state siting boards and not utility commissions.[164] We urge the Commission not to rely on state siting board

[162] Technical Conference Transcript at 260:7–261:13.
[163] Fifth Meeting of the Joint Federal-State Task Force, at 28:4–9 (Nov. 15, 2022).
[164] *See, e.g.,* MASS. GEN. LAWS Ch. 164 § 69H (creating an Energy Facilities Siting Board and including two state utility regulators among its nine members); New Hampshire RSA 162:H-16 (listing factors that guide the Site Evaluation Committee's decisions).

decisions for any ratemaking purpose. State siting boards may not consider need or ratepayer costs and may be ill-equipped to assess project alternatives.

Post-technical conference filings by Professor Joshua Macey and the Organization of PJM States explore some differences between state siting laws, and highlight that most state laws exempt certain lower voltage projects from any permitting requirements.[165]

b. In response to question 7, we suggest that the Commission narrow its prudence presumption and require a utility to demonstrate prudence of certain *self-planned* projects unless it adopts a Ratepayer Transmission Monitor (RTM). Our proposal exempts low-voltage projects that are approved by the state utility regulator in a "robust" permitting proceeding. The Commission should establish objective criteria for "robustness," and could then rely on a utility's representations that the state permitting process met those criteria. Utilities should also file state commission orders with annual formula rate updates or in other relevant rate proceedings. We do not see a need for state authorities to file attestations.

For this state-approval exemption, we suggest that the Commission only exempt low-voltage projects that are "not integrated with the transmission system as a whole."[166] To the extent state permitting proceedings consider whether a project is needed, that analysis may focus on the applicant utility's ability to provide reliable and affordable service to the captive ratepayers in its state-granted service territory. State permitting authorities may ignore the regional context. Moreover, state permitting authorities may not have any insight into whether there were more

[165] Post Technical Conference Comments of Joshua C. Macey, Docket AD22-8 (Mar. 23, 2023); Post-Technical Conference Comment of the Organization of PJM States, Docket No. AD22-8 (Mar. 23, 2023).
[166] *Mansfield Municipal Electric Department, et al. v. New England Power Co.*, 97 FERC ¶ 61,134, at p. 61,613 (2001).

efficient regional alternatives to the proposed project. The Commission is the only regulator that should make such determinations. To determine whether a project is integrated with the transmission system, the Commission could set a bright-line threshold, such as 100 kV,[167] or apply the five-factor *Mansfield* test.[168]

The Commission should only exempt from its review projects that are approved by state utility regulators who consider need and cost. We suggest the following objective criteria to determine if the Commission can rely on a state proceeding:

- The permitting process was conducted by the state utility commission;
- The permitting process culminated in an order approving the applicant utility's project, and not an order approving a settlement;
- The order finds that the project is needed given its projected costs; and
- At least one party in the proceeding opposed the project and that party filed evidence in the proceeding.

c. and d. For projects that are not presumed prudent pursuant to the approach we outline in questions 7 and 11.b, the utility would be unable to automatically flow project capital expenditures to consumers via formula rates. In response to question 7, we suggest that the Commission allow state regulators to participate in a subsequent proceeding to determine prudence of those expenses and whether the rate is just and reasonable. Alternatively, the Commission could allow the utility to recover all capital expenses through its formula rate and subsequently initiate a

[167] Order No. 743, 133 FERC ¶ 61,150 at P 73 (2010) (". . . many facilities operated at 100 kV and above have a significant effect on the overall functioning of the grid. The majority of 100 kV and above facilities in the United States operate in parallel with other high voltage and extra high voltage facilities, interconnect significant amounts of generation sources and operate as part of a defined flow gate, which illustrates their parallel nature and therefore their necessity to the reliable operation of the interconnected transmission system").
[168] *Supra* note 166.

prudence proceeding. If the expenses are found imprudent, the Commission could order refunds.[169]

Other Questions

12. No response.

Conclusion

We commend the Commission for opening this proceeding, holding the October technical conference, and inviting comments. We urge the Commission to protect consumers from excessive transmission costs by imposing reforms to transmission planning and cost recovery that will hold utilities accountable for their decisions.

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[169] The Commission has legal authority to order such refunds. *See supra* note 109.