UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Management	Docket No. AD22-8-000
Joint Federal-State Task Force on Electric Transmission	Docket No. AD21-15-000

**POST-TECHNICAL CONFERENCE COMMENTS
OF
TRANSMISSION ACCESS POLICY STUDY GROUP**

The Transmission Access Policy Study Group ("TAPS") welcomes the opportunity to submit comments following up on the important October 6, 2022 technical conference on transmission planning and cost management,[1] in which TAPS actively participated.[2] As transmission dependent utilities ("TDUs") that have already faced steep transmission rate increases in recent years,[3] TAPS recognizes the critical importance of integrating cost management into all aspects of transmission planning, and it strongly supports the Commission's objective to minimize and mitigate the costs associated with the anticipated expansion of the transmission grid to accommodate the Nation's changing resource mix. We urge the Commission to adopt a robust and holistic approach to

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[1] Notice Inviting Post-Technical Conference Comments (Dec. 23, 2022), eLibrary No. 20221223-3017 ("Notice").

[2] Dan O'Hagan, Florida Municipal Power Agency ("FMPA"), spoke on behalf of TAPS and FMPA. In addition, other TAPS members participated as panelists. Lisa McAlister, American Municipal Power ("AMP"), spoke on behalf of AMP and the American Public Power Association, and Randy Howard participated on behalf of the Northern California Power Agency. *See* Supplemental Notice of Technical Conference (Oct. 4, 2022), eLibrary No. 20221004-3057.

[3] *See* Comments of Transmission Access Policy Study Group at 6-7 & nn.6-7, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Oct. 12, 2021), eLibrary No. 20211012-5388 ("TAPS ANOPR Comments") (examples of transmission rate hikes borne by TAPS members and the consumers that rely on them for affordable electricity).

achieving that objective. Specifically, the Commission should take the following steps, all of which are well within its responsibility and authority pursuant to section 206 of the Federal Power Act ("FPA").[4]

- Effective cost containment requires adoption of proposals included in TAPS's comments in the *Building for the Future* NOPR[5] (Part I.A), including:
    - Long-term scenarios to enable comparison of new remote versus local generation options should be required to the extent that regions are required, or decide, to identify remote geographic zones for new generation as part of their Long-Term Regional Transmission Planning.
    - Least-regrets or no-regrets approaches in Long-Term Regional Transmission Planning should be endorsed and strongly encouraged.
    - An affordability metric should be required as part of the Long-Term Regional Transmission Planning project selection process.
    - The NOPR's right-sizing proposal for replacement projects should be made more inclusive to better achieve more cost-effective and efficient transmission expansion.
    - To achieve their purpose, the NOPR's three-meeting proposal for local planning should be modified, including by requiring Transmission Owners ("TOs")[6] to respond substantively to comments and questions submitted by stakeholders.
    - To produce more efficient and cost-effective projects, non-RTO region planning processes require reevaluation and enhancement.

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[4] 16 U.S.C. § 824e. *See also S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d 41, 56 (D.C. Cir. 2014) (recognizing, while interpreting the Commission's section 206 authority, that "[t]he authority and obligation that Congress vested in the Commission to remedy certain practices is broadly stated"). Thus, for instance, the Commission could find unjust and unreasonable the "practice" of passing through to ratepayers annual inputs to formula transmission rates that have received minimal, if any, Regional Transmission Organization ("RTO") review, and that are subject to limited Commission oversight, on the grounds that this "practice" may allow transmission owners to recover unjust and unreasonable rates. *See* nn.57 & 58. The Commission could then use its section 206 authority to address this "practice" by requiring the creation of a Customer Transmission Monitor in RTO regions, as TAPS proposes.

In response to Notice, Question 5.g, we provide a more detailed discussion of the Commission's authority to require an Independent Transmission Monitor in non-RTO regions in Part II.A.3 below.

[5] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("NOPR").

[6] Except in Part II below, we use the term TO to encompass both TOs and Transmission Providers ("TPs").

- Given their demonstrated cost-reducing impacts, meaningful promotion of inclusive joint ownership arrangements should be an important feature of Commission cost containment efforts. Part I.B.
    - The Commission should adopt TAPS's narrowed approach to the *Building for the Future* NOPR's proposed conditional joint ownership Right of First Refusal ("ROFR"), so that it is available only to incumbent TOs that offer a meaningful opportunity for load-ratio-share joint ownership on reasonable terms to all Load-Serving Entities ("LSEs")[7] in the TO's footprint; or it should take other actions to promote inclusive joint ownership arrangements.

- Given the absence of any regional project in any non-RTO region since Order 1000,[8] the Commission can and should mandate creation and funding of a "baseline" Independent Transmission Monitor ("ITM") in non-RTO regions, subject to periodic reassessment. Part II.A. In response to the Notice's question, TAPS demonstrates the Commission's authority to require such an ITM. TAPS's proposed baseline ITM would include the following key features:
    - The Baseline ITM would monitor and document performance of the region's regional planning process; review and verify transmission studies, with authority to request TPs perform additional planning studies; evaluate the regional planning processes; and recommend improvements.
    - The ITM would periodically report to stakeholders, and file with the Commission (in a proceeding that would invite public comment), the results of the ITM's performance of its responsibilities, including recommendations for improvements.
    - To select the ITM, non-RTO region TPs should be required to solicit input from stakeholders (including LSEs, states, and state consumer advocates) and, after considering such input, submit their proposed ITM to the Commission for review.
    - ITM costs should be equitably shared by all load in the planning region.

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[7] FPA section 217(a)(2)'s LSE definition, which feeds off of section 217(a)'s definitions of "distribution utility," "service obligation," and "state utility," encompasses electric utilities that have a service obligation to end-use customers, as well as municipal joint action agencies and generation and transmission ("G&T") cooperatives (or others) through which they do so. 16 U.S.C. § 824q(a). TAPS uses this statutory definition, which the Commission used in its rule providing for LSE priority in the allocation of long-term firm transmission rights, throughout our comments. *See Long-Term Firm Transmission Rts. in Organized Elec. Mkts*., Order No. 681, 116 FERC ¶ 61,077, PP 34, 43, *clarified*, Order No. 681-A, 117 FERC ¶ 61,201 (2006), *clarified*, Order No. 681-B, 126 FERC ¶ 61,254 (2009).

[8] *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), *reh'g denied*, Order No. 1000-A, 139 FERC ¶ 61,132 ("Order 1000-A"), *on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *review denied sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam).

- In RTO regions, the Commission can and should mandate creation and funding of a Customer Transmission Monitor ("CTM"), subject to periodic reassessment. Part II.B.
    - The CTM's purpose is to facilitate the ability of transmission customers, states, and state consumer advocates to review annual updates to formula rates in RTO regions, on a consistent basis.
    - The CTM would be charged with reviewing the annual updates and associated supporting data, asking discovery requests, submitting informal challenges, and participating in pre-formal challenge negotiations. It would be permitted to cooperate with other stakeholders on its review and share information with them, so long as the stakeholder has executed any required confidentiality agreement associated with data provided by the TO/RTO.
    - The CTM should be selected (preferably on an RTO-wide basis) by transmission customers, state commissions, and state consumer advocates. If these customer-side stakeholders cannot agree on a CTM, that region's independent market monitor ("IMM") should select the CTM, subject to Commission review, from among the candidates proposed by the transmission customers, state commissions, and state consumer advocates.

- The Commission should revise its Order 890[9] principles to provide for enhanced transparency and information sharing, modeled on the stakeholder transmission planning and asset review processes implemented by Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE"). Part III. The enhanced transparency process should include:
    - Every six months, each TO would be required to provide transmission customers, states, and other stakeholders with a comprehensive spreadsheet report. The report should contain detailed information on each transmission project constructed or planned by the TO, including asset management/supplemental projects, local projects, and regional projects, that exceed $1 million. It should list all construction activities for each transmission project for which there were capital expenditures in the last five years, or for which any future expenditures are anticipated in the next five years. For projects greater than $10 million, information on five additional years of anticipated future expenditures should be provided.
    - Broad discovery rights for transmission customers, states, and other stakeholders, subject to reasonable confidentiality protections. Such rights

[9] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119 (2007) ("Order 890"), *order on reh'g and clarification*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

would enable them to access, among other things, internal documents showing the approval process, the project's full business case, and the alternatives and design options considered, which can be crucial to ensuring cost-effective and efficient use of consumer dollars.

  - Information obtained through the enhanced transparency process—both the periodic spreadsheet reports and any materials received through discovery—may be used by recipients in any proceeding or forum, subject to reasonable confidentiality protections.
  - TOs should be required to timely and substantively respond to stakeholder input with regard to asset management/supplemental projects, and projects subject to Order 890 or Order 1000 planning processes.

- The Commission should direct all IMMs to use the market data that are already uniquely available to them to identify and report inconsistencies with the assumptions used in the planning process, consistent with the practice of Southwest Power Pool, Inc.'s ("SPP") market monitoring unit ("MMU"). TAPS is *not* seeking to expand the IMMs' role in planning beyond confirming that planning assumptions do not conflict with market data the IMM otherwise receives. Part IV.A.

- The Commission should make other Order 890 process improvements (Part IV.B), including:
  - Requiring collaborative, interactive, joint planning processes, in which TOs would invite input from affected transmission customers at all stages of the planning process (local, regional, and interregional), allow them to participate in decision-making, and assure that their views are considered on a non-discriminatory basis.
  - Reexamining exclusions from Order 890 planning processes. For example, the Commission should include other "asset management projects and activities [that] do not expand the grid,"[10] within Order 890's requirements.
  - Enhancing transparency and ensuring TOs not only allow stakeholder input, but also substantively respond to that input.

- Other formula rate process improvements are needed to ensure just and reasonable rates:
  - The Commission should explicitly adopt the transmission formula rate protocols of the Midcontinent Independent System Operator, Inc. ("MISO Protocols") as the minimum standard. It should make clear that in response to a complaint that includes a preliminary showing that a TO's protocols are inferior to the MISO Protocols in some respect(s), the

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[10] *See* n.101, below.

Commission will either: (1) grant the complaint and require a corrective compliance filing by the TO; or (2) issue a show cause order requiring the TO to either modify its protocols or explain why its formula rate protocols remain just and reasonable. Part V.A.

- Where service company costs are included in transmission formula rate inputs, protocols should expressly provide access to affiliated service company cost support data. The service company's invoice to its affiliated TO is not sufficient to ensure just and reasonable transmission rates, free of affiliate abuse. TOs with formula rates that include service company costs should be required to: (1) obtain requested service company information from its affiliate; and (2) provide it to the requesting Interested Party[11] as if the TO had performed the service itself. Part V.B.
- To ensure timely responses to data requests and thereby enable timely and effective identification of formula rate issues, the Commission should require protocols to provide for the appointment of an Administrative Law Judge as Discovery Master. Part V.C.

INTEREST OF TAPS

TAPS is an association of TDUs in thirty-five states promoting open and non-discriminatory transmission access.[12] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members recognize the importance of a robust transmission grid, and have long been outspoken on the need for improved transmission and ways to get needed transmission built.[13] TAPS recognizes the critical roles played by an open, inclusive, and transparent planning process, and fair cost allocation, in achieving needed transmission expansion.

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[11] In these comments, the capitalized term "Interested Party" or "Interested Parties," adopts the meaning used in the MISO formula rate protocols orders. *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,149, P 34 (2013) (subsequent history omitted) ("The Commission, therefore, directs MISO and the MISO transmission owners to revise the formula rate protocols to include all interested parties in information exchange and review processes, including but not exclusive to customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorney generals.").

[12] *See* TAPS, https://www.tapsgroup.org (last visited Mar. 9, 2023). Jane Cirrincione, Northern California Power Agency, is the TAPS Chair; Dave Osburn, Oklahoma Municipal Power Authority, is the Vice Chair. Terry Huval is TAPS's Executive Director.

[13] *See* TAPS, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost (June 2004), https://www.tapsgroup.org/wp-content/uploads/2013/01/effectivesolutions.pdf ("TAPS 2004 White Paper").

As municipal, cooperative, and investor-owned LSEs, TAPS members are responsible for providing reliable and affordable service to the consumers and businesses that rely on them and their members. Our paramount concern is reliable service at reasonable cost to consumers, consistent with FPA section 217(b)(4)'s[14] directive that the Commission facilitate the planning and expansion of the grid to meet the reasonable needs of LSEs to satisfy their service obligations. TAPS vigorously supported Order 1000's objective of ensuring selection of more efficient and cost-effective alternatives in transmission plans. This goal should guide the Commission as it addresses how to plan and expand the grid to accommodate the resource transformation now underway, while minimizing the associated costs to consumers, consistent with the Commission's statutory obligation to ensure just and reasonable rates.

In addition to actively participating in all previous Commission transmission planning rulemaking proceedings, TAPS filed extensive comments in the *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* proceeding, Docket No. RM21-17, responding to both the Advance Notice of Proposed Rulemaking,[15] and the Notice of Proposed Rulemaking.[16] As noted above, TAPS and its members sponsored three panelists at the October 6 Technical Conference.

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[14] 16 U.S.C. § 824q(b)(4).

[15] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR"). *See* TAPS ANOPR Comments.

[16] *See* Initial Comments of Transmission Access Policy Study Group, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Aug. 17, 2022), eLibrary No. 20220817-5183 ("TAPS Initial NOPR Comments"); Reply Comments of Transmission Access Policy Study Group, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Sept. 19, 2022), eLibrary No. 20220919-5104 ("TAPS Reply NOPR Comments") (collectively, "TAPS NOPR Comments").

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COMMENTS

I. TO BE MEANINGFUL, COST CONTAINMENT SHOULD BE AN INTEGRAL PART OF THE TRANSMISSION PLANNING PROCESS

TAPS greatly appreciates the Commission's interest in developing and improving mechanisms to mitigate the cost to consumers of the anticipated expansion of the transmission grid. In addition to proposing various cost containment actions in response to the Notice (see Parts II-V below), TAPS urges the Commission not to overlook key steps it can and should take to build cost containment into the planning process.[17] We highlight a number of such consumer-protective measures below.

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[17] TAPS also urges the Commission to advance its cost-containment objectives by eliminating or reducing cost-increasing incentives. For example, it should restrict the RTO Adder, as proposed in the pending Supplemental Incentives NOPR, *Elec. Transmission Incentives Pol'y Under Section 219 of the Fed. Power Act,* 175 FERC ¶ 61,035, P 5 (2021), consistent with TAPS's comments. *See* Comments of Transmission Access Policy Study Group at 2-3, *Elec. Transmission Incentives Pol'y Under Section 219 of the Fed. Power Act*, Docket No. RM20-10 (June 25, 2021), eLibrary No. 20210625-5171. With limited exceptions identified in Comments of the Transmission Access Policy Study Group at 7, 29-38, 103-105, *Elec. Transmission Incentives Pol'y Under Section 219 of the Fed. Power Act*, Docket No. RM20-10 (July 1, 2020), eLibrary No. 20200701-5410 ("TAPS 2020 Incentive NOPR Comments"), (e.g., eliminating the Transco adder; preserving and enhancing the encouragement of inclusive joint ownership), the Commission should not move forward with the 2020 Incentives NOPR, *Elec. Transmission Incentives Pol'y Under*

A. The Commission Should Adopt the Cost-Containment Proposals Included in TAPS NOPR Comments.

In TAPS's *Building for the Future* NOPR comments, we identified multiple ways to minimize costs to consumers, consistent with the Commission's obligations under FPA sections 217(b)(4), 205,[18] and 206,[19] including:

- ***Long-term scenarios to enable comparison of new remote versus local generation options*** should be required to the extent that regions are required, or decide, to identify remote geographic zones for new generation as part of their Long-Term Regional Transmission Planning. Long-term planning should facilitate comparisons between alternatives and their associated trade-offs between generation and transmission costs, focusing on what matters: the delivered cost of electricity to consumers.[20]

- ***Least-regrets or no-regrets approaches*** in Long-Term Regional Transmission Planning should be endorsed and strongly encouraged. At minimum, the Commission should require that regions choosing not to use those approaches explain that decision, e.g., demonstrate how their alternative project selection criteria appropriately account for the uncertainties inherent in predicting future transmission needs, and how their selection criteria will satisfy the crucial proposed requirement to "maximize benefits to consumers over time without over-building transmission facilities,"[21] and result in just and reasonable rates consistent with the FPA.[22]

- An ***affordability metric*** should be required as part of the Long-Term Regional Transmission Planning project selection process. Making such information available to states and stakeholders on the projected transmission rate/consumer cost impacts if

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Section 219 of the Fed. Power Act, 170 FERC ¶ 61,204, *corrected*, 171 FERC ¶ 61,072 (2020). *See also* TAPS Initial NOPR Comments at 27-29 with respect to Construction Work in Progress.

[18] 16 U.S.C. § 824d.

[19] Other commenters made additional suggestions that should aid cost containment in the Long-Term Regional Transmission Planning process, e.g., by revisiting projects selected in prior cycles based on changes in expected benefits or costs. *See* Initial Comments of the American Public Power Association at 8, 35-36, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Aug. 17, 2022), eLibrary No. 20220817-5214 ("APPA Initial NOPR Comments").

[20] *See* TAPS Initial NOPR Comments at 10.

[21] NOPR P 245.

[22] *See* TAPS Initial NOPR Comments at 18.

the project or portfolio is selected in the Long-Term Regional Transmission Plan for regional cost allocation will enhance transparency and improve decision-making.[23]

- Expand the NOPR's right-sizing proposal for replacement projects.[24]
    - Include right-sizing requirements in all Order 1000 regional planning processes, not just Long-Term Regional Transmission Planning.[25]
    - Enable planning regions to evaluate alternatives that can increase options for the future, not just those producing immediate increases in capacity.[26]
    - Reduce the proposed 230 kilovolt ("kV") cut-off, which would have the unintended consequence of encouraging TOs to simply replace 161 kV facilities that merit upgrading.[27]
    - If the TO proceeds with in-kind replacement after the regional planning process has identified and selected a more cost-effective and efficient alternative, exclude the replacement project from formula rates and require a section 205 filing subject to a presumption of *imprudence*.[28]

TAPS's *Building for the Future* NOPR and ANOPR comments also suggested specific Order 890 transmission planning process improvements to better protect consumers from cost increases.[29] For example:

- Modifying the NOPR's three-meeting proposal for local planning to make it more effective, including requiring TOs to respond to comments and questions submitted.[30]

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[23] *See id.* at 18-20.

[24] *See* Notice, Question 3.

[25] *See* TAPS Initial NOPR Comments at 63-64.

[26] *See id.* at 64-65.

[27] *Id.*

[28] *See id.* at 66-67.

[29] *See* Notice, Question 2.

[30] *See* TAPS Initial NOPR Comments at 60-62. Our other requested improvements include: (1) TOs must post criteria, models, and assumptions sufficient to enable stakeholders to evaluate and replicate findings; (2) TOs must distribute info sufficiently in advance of meetings; (3) longer time between Assumptions, Needs, and Solutions meetings; (4) Solutions meeting should be a meaningful opportunity to consider alternatives; and (5) Dispute resolution available. *Id.*

- Reexamining exclusions from Order 890 planning processes and regional review given their impact.[31]
- Requiring more collaborative, interactive, and joint local planning processes, consistent with TAPS's position in the Order 890 rulemaking, as explained in Part IV.B below.[32]

The instant comments build on these suggestions and recommend additional transparency improvements for both transmission planning and formula rate processes.

In addition, TAPS's NOPR and ANOPR comments[33] called out the critical need for enhancements to the planning processes of non-RTO regions, given their failure to produce *any* regional projects in the decade since Order 1000 issued.[34] We recommended an ITM (see Part II. A below), as well as other important changes such as requiring production cost savings to be considered as a metric for economic projects,[35] and addressing other barriers that have effectively foreclosed selection of more cost-effective and efficient projects in non-RTO regions.

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[31] *See* TAPS Initial NOPR Comments at 66, citing TAPS ANOPR Comments at 22-25, which cross reference the discussion at 52.

[32] *See* Initial Comments of the Transmission Access Policy Study Group, *Preventing Undue Discrimination & Preference in Transmission Serv.*, Docket Nos. RM05-17, RM05-25 (Aug. 7, 2006), eLibrary No. 20060807-5089 ("TAPS Order 890 Initial Comments"); Reply Comments of the Transmission Access Policy Study Group, *Preventing Undue Discrimination & Preference in Transmission Serv.*, Docket Nos. RM05-17, RM05-25 (Sept. 20, 2006), eLibrary No. 20060920-5084 ("TAPS Order 890 Reply Comments") (collectively, "TAPS Order 890 Comments").

[33] *See* TAPS Initial NOPR Comments at 68-71; TAPS ANOPR Comments at 15-19. *See also* Summary Statement of Dan O'Hagan on behalf of the Florida Municipal Power Agency and the Transmission Access Policy Study Group for the October 6, 2022 Technical Conference (Sept. 22, 2022), eLibrary No. 20220922-5032 ("O'Hagan Summary Statement").

[34] NOPR P 39.

[35] TAPS Initial NOPR Comments at 16.

B. Inclusive Joint Ownership Can Play an Important Role in Containing Costs, Reinforcing the Need to Promote Such Arrangements.

TAPS has long advocated for "inclusive joint ownership arrangements"—which invite meaningful ownership participation on reasonable terms to all LSEs in the relevant footprint—as crucial to getting needed transmission built at reasonable cost. TAPS's 2021 White Paper[36] and *Building for the Future* ANOPR comments[37] highlighted many benefits such joint ownership arrangements can provide, including improving transmission planning to produce a more efficient build-out; facilitating state siting; making it easier for LSEs to accept cost increases associated with new transmission by providing a hedge; and reducing the costs of needed facilities. All these benefits mitigate costs to consumers.

TAPS's initial comments on the *Building for the Future* NOPR documented that, in addition to those advantages,[38] inclusive joint ownership arrangements produce reliable and quantifiable cost containment benefits:[39]

- Public power and cooperative entities use their net transmission project earnings to offset the costs of serving their end-use customers, thus reducing the electric bills of those customers; and
- Their non-profit and tax-exempt status otherwise reduces costs to consumers in the TO's footprint (pricing zone in an RTO).

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[36] TAPS, *Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Site and Build Transmission Need to Support Our Changing Resource Mix* (June 25, 2021), https://www.tapsgroup.org/wp-content/uploads/2021/09/TAPS-Inclusive-Joint-Ownership-White-Paper.pdf ("TAPS 2021 White Paper"). Additional detail is provided in the TAPS 2004 White Paper. *See also* TAPS 2020 Incentive NOPR Comments at 29-38.

[37] TAPS ANOPR Comments at 9-11.

[38] *See* TAPS Initial NOPR Comments at 29.

[39] *Id.* at 40.

To demonstrate the latter point, we gathered data from several TAPS members that have participated in various forms of inclusive joint ownership. Analysis of that information provides a consistent picture of reliable, quantifiable savings to all transmission customers in the TO's footprint (as well as others that are allocated the costs of the facilities).[40]

The cost savings quantified by TAPS are consistent with those documented in the APPA Initial NOPR Comments, which feature the declaration of James Pardikes of MCR Performance Solutions.[41] Mr. Pardikes draws on his considerable experience with joint ownership arrangements involving public power and cooperatives to detail their many practical, financial, and public policy benefits, adding further depth and perspective to TAPS's quantification of a subset of those benefits. The National Rural Electric Cooperative Association's ("NRECA") comments likewise describe the financial and cost-reducing, hedging, siting, and permitting benefits produced by such participation, supported by a report from GDS Associates, Inc.[42]

And joint ownership with customers protects against undue discrimination in planning and gives consumers an oversight role in the project development process. For example, the Vermont Transco's inclusive joint ownership arrangement[43] gives public

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[40] *See id.* at 39-45 and Appendix A.

[41] APPA Initial NOPR Comments, Pardikes Declaration at 5-10. *See* also TAPS Reply NOPR Comments at 6-7.

[42] Comments of the National Rural Electric Cooperative Association at 60-61 and attached Report of GDS Associates, Inc. at 26-27, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Aug. 17, 2022), eLibrary No. 20220817-5316.

[43] The Vermont Transco is the most longstanding inclusive transmission joint ownership arrangement, dating back to 1956. Vt. Elec. Power Co., *About Vermont Electric Power Company*, https://www.velco.com/about (last visited Mar. 9, 2023). A recent filing to the Vermont Public Utility Commission details the inclusive (and approximately load-reflective) participation of sixteen tax-exempt municipal and cooperative utilities in a $40 million equity offering issued to fund Vermont Transco's

power co-owners a voice in decision-making, creating the opportunity for them to be an effective force for cost-containment. This was illustrated by their role in shaping a more cost-effective solution to the Sheffield-Highgate Export Interface constraint that restricts deliveries from Northern Vermont to the rest of New England. An initial proposal to alleviate the constraint using new 115 kV projects raised significant cost and consumer impact concerns among public power co-owners, so an interactive process including engineers from Vermont Transco's co-owners was convened to develop and evaluate alternatives.

Because their support was needed to approve any consensus solution, public power co-owners were involved in that process from the very beginning. And after evaluating dozens of options, Vermont Transco adopted a much more cost-effective solution to address the constraint: using a combination of lower-voltage transmission upgrades and adding automatic voltage regulation equipment to generators in the constrained area, which partially relieved the constraint and could be implemented much more quickly than the originally proposed 115 kV lines; and, in the longer-term, upgrading and reconductoring an existing high-voltage transmission line, which had already been identified as needing future replacement, with a design that will provide options for even more expansion within the existing rights-of-way later.

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ongoing major capital expenditures. The tax-exempt entities' collective share is 22.05%, with Green Mountain Power ("GMP"), a taxable entity, owning the remaining 77.95%. *See* Petition of Vermont Transco LLC, Vt. Pub. Serv. Comm'n Case No. 21-3724-PET, Ex. MCN-1 and MCN-3 (Sept. 2, 2021), (available at https://epuc.vermont.gov/?q=downloadfile/518598/162731, external pagination pages 13 & 15 of 71).

In its NOPR comments, International Transmission Company also recognized the "outsize[d]" benefits of joint ownership with embedded LSEs, including their contribution to cost discipline:[44]

> [M]any smaller electric cooperatives and public power entities may not have the financial capital to finance a large ownership share of a major transmission facility. Yet these entities may be able to provide outsize benefit to the transmission development process . . . . Smaller entities, particularly those which are geographically close to a project, are also likely to be users of the transmission facility, and will thereby be incentivized to contribute cost discipline to the project.

Thus, the Commission should advance its cost containment objectives by adopting TAPS's narrowed approach to the *Building for the Future* NOPR's proposed conditional joint ownership ROFR. Specifically, the conditional ROFR should be available only to incumbent TOs that offer a meaningful opportunity for load-ratio-share joint ownership on reasonable terms to all LSEs in the TO's footprint.[45] Those LSEs are likely to be public power or non-profit cooperatives that provide the cost-containment benefits highlighted above, i.e., they: (1) use their net transmission project earnings to offset their customer costs; and (2) their participation otherwise reduces costs to consumers in the TO's footprint. Restricting the NOPR's conditional joint ownership ROFR in this way furthers consumer-savings objectives, while leaving room for competitive projects where incumbent TOs choose not to share ownership in a manner

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[44] Comments of International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC at 42-43, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Aug. 17, 2022), eLibrary No. 20220817-5163.

[45] For a fuller description of TAPS's tailored approach to the NOPR's proposed conditional ROFR, *see* TAPS Initial NOPR Comments at 29-60, summarized at 5-6; TAPS Reply NOPR Comments at 2-9.

that would achieve those goals. Finding this "sweet spot" is important to TAPS. We have long advocated for inclusive joint ownership arrangements to get needed transmission built at reasonable cost, *and* supported competitive transmission development, which has saved consumers money where effectively implemented.[46] Recognizing that competitive transmission development has been limited in various regions since Order 1000,[47] we ask that the Commission adopt the *Building for the Future* NOPR's conditional ROFR, tailored as TAPS has proposed.

If it does not do so, the Commission should take other actions to provide for and promote inclusive joint ownership arrangements. For example, it could make inclusive joint ownership a basis for exempting the inclusive jointly-owned facilities from whatever heightened scrutiny the Commission requires as a result of its cost containment efforts. Or the Commission could use a different mechanism to make promotion of inclusive joint ownership a part of any final rule emerging from the *Building for the Future* proceeding and this cost containment effort. Options to do so include the proposals TAPS urged in its ANOPR comments and Inclusive Joint Ownership White Paper (e.g., make joint ownership a factor in project selection; include opportunities for TDU planning and joint ownership as a feature of the local planning process).[48]

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[46] *See* TAPS Initial NOPR Comments at 30 n.77; TAPS ANOPR Comments at 52 n.109.

[47] NOPR P 349.

[48] *See* TAPS 2021 White Paper at 8-10; TAPS ANOPR Comments at 13-15.

II. NEW COST MANAGEMENT FUNCTIONS IN NON-RTO AND RTO REGIONS[49]

As TAPS approached the invitation for follow-up comments on possible new cost management functions, an overriding consideration was that new functions should reflect the differing planning experience and needs of the two very different types of planning regions we have in this country—non-RTO regions and RTO regions.[50] One size does not fit all.

As recognized in the *Building for the Future* NOPR,[51] no regional project has emerged from *any* non-RTO region since Order 1000. Through TAPS's ANOPR and NOPR comments and Dan O'Hagan's participation in the October 6 Technical Conference, we also provided evidence of the severe deficiencies in the regional planning process in Florida, which has failed to address significant congestion in central Florida—an area with multiple overlapping utilities that has seen significant population growth and is an attractive location for siting generation.[52] Mr. O'Hagan provided several concrete examples of how effective regional planning has been thwarted by loopholes and limitations in Florida's Order 1000 processes, as they have been implemented.[53] This evidence has not been contested, despite repeated opportunities.

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[49] *See* Notice, Questions 5 and 6.

[50] *Id.*, Question 5.g.

[51] NOPR P 39.

[52] *See* TAPS ANOPR Comments at 15-19; TAPS Initial NOPR Comments at 69-70; O'Hagan Summary Statement; Transcript of the Transmission Planning and Cost Management Technical Conference held on October 6, 2022 at 29:20-31:20 (Nov. 1, 2022), eLibrary No. 20221101-4000 ("Technical Conference Tr.").

[53] O'Hagan Summary Statement at 7-8 and Technical Conference Tr. at 29:20-31:20; 47:7-48:11; 70:2-71:6. Mr. O'Hagan describes, among other things, the TPs' control over the timing and manner of disclosing local plans, which a regional project could economically displace (using the "avoided cost" metric) and their ability to withdraw a local project where an alternative was offered, have operated as barriers.

Clearly, something must be done to assess, monitor, and report on the regional planning processes of non-RTO regions, and to suggest improvements to make them effective. And just the presence of an independent "cop on the beat" could deter actions that have undermined the effectiveness of those processes.[54] We also recognize, however, the importance of keeping any ITM role lean, to keep costs down and avoid interfering with the planning process. We therefore propose a "baseline" ITM that reviews, monitors, and reports on the processes, requests the TPs to undertake additional studies, and recommends process changes. *Notably, we are NOT advocating an ITM to perform transmission studies or override planning decisions made by the regions*. And we recommend periodic reevaluation by the Commission of this limited ITM.[55]

RTO regions are in a very different place. While RTOs themselves are influenced by the need to avoid TO departure (because RTO participation is generally voluntary), regional planning has produced some beneficial projects. For regionally planned projects, stakeholders have more confidence in RTO planning processes that have some degree of transparency, and planning decisions are out of the direct control of the TOs. RTO regions also have IMMs.[56]

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[54] *See, e.g.*, Technical Conference Tr. at 274:6-10 (Karen Onaran (Electricity Consumers Resource Council), characterizing an ITM as "a cop on the beat, but not necessarily enforcing anything, but [who] can raise flags, can report on gaps and things that they are concerned about if they see concerns with a transmission planning process, or what the decision was."); *Id.* at 211:19-23 (Chairman Ronald T. Gerwatowski (Rhode Island Public Utilities Commission), explaining that "one of the parts about having an independent monitor here is that it suddenly . . . there is a risk here. We've got to be playing closer attention to it. And that creates the attention, as well as the substance of the review.").

[55] Notice, Question 5.e.

[56] In Part IV.A, TAPS urges the Commission to require RTO IMMs to use the market data they alone possess to check planning assumptions, consistent with best practices currently used by the SPP MMU.

On the other hand, formula rates are the norm in RTO regions, and formula rate inputs receive little if any RTO review.[57] Given the number of public utilities using formula rates in RTOs, and the limited Commission involvement in their ongoing operation,[58] there is both the incentive and opportunity for TOs to use this mechanism to recover unjust and unreasonable rates, especially given the contemplated transmission expansion. As a cost containment measure, TAPS therefore proposes creation of a CTM to review the annual inputs to formula transmission rates in RTO regions,[59] funded by all load on a load-ratio basis through the RTO transmission rates.

TAPS takes no position on the benefits and detriments of adding an ITM in the RTO context, leaving that to individual TAPS members. However, if an ITM were established, the Commission should periodically review the need for, role, and scope of the ITM.[60]

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[57] *See, e.g.*, Pre-Conference Comments of Maine Public Utilities Commission Chair Philip L. Bartlett II at 3 (Oct. 4, 2022), eLibrary No. 20221004-5145 ("[ISO New England, Inc. ("ISO-NE")] is not active in the formula rate updates process."); Statement of Ronald T. Gerwatowski, at 6-7 (Oct. 4, 2022), eLibrary No. 20221004-5142 ("ISO-NE . . . has no assigned role to be active in [the formula rate update and true-up process]. Thus, the burden of policing the rate is placed on state agencies and consumer advocates, which do not have a fraction of the resources and transmission rate expertise of utilities").

[58] *See, e.g.,* Technical Conference Tr. at 180:21-183:21 (Bob Weishaar (Industrial Energy Consumers of America, America Forest & Paper Association, PJM Industrial Customer Coalition, and Coalition of MISO Transmission Customers), responding to a question from Commissioner Phillips, explains that "the rubber hits the road when the costs are flowed through [the formula rate] on an annual basis, and we get annual informational updates. [The Commission's Office of Administrative Litigation] staff is not involved for whatever reason, I don't know whether that's an authority issue, or a resource issue . . ."); *Id.* at 193:13-194:08 (then-Chairman Glick, acknowledging that though the Commission's "audit process is very good," it's a "limited opportunity," as the Commission has "limited staff . . . to do audits"); *Id.* at 282:10-283:12 (Commissioner Clements, recognizing that the Commission's audit enforcement team "can only do 12 to 14 [audits] a year" and remarking that the Commission "still ha[s] this structural problem, the inability to really get—dig in at the formula rates step . . .").

[59] Given the varying transmission rate situation in non-RTO regions, establishment of a CTM in non-RTO regions is not necessary and would add complication.

[60] Notice, Question 5.e.

A. The Commission Should Mandate Creation and Funding of a Baseline ITM in Non-RTO Regions.

For the reasons discussed above, TAPS is proposing that the Commission require non-RTO regions to have a "baseline ITM" that reviews and reports on the regional planning process; requests the TPs to undertake additional studies; and evaluates the regional planning process and recommends process changes. We do *not* propose creating a "regional planner-in-chief"; the baseline ITM would not perform transmission studies or override planning decisions made by the region.

1. Baseline ITM Functions[61]

TAPS's proposed baseline ITM would perform the following functions:

- *Monitor and document performance of the regional planning process.* The ITM should monitor and document the Order 1000 process, providing regular updates on ongoing performance on a schedule proposed by the region and approved by the Commission. Because current processes may be moribund (since Order 1000 processes in non-RTO regions have produced no regional projects, transmission developers may have given up), this function must also encompass historical performance. The ITM's monitoring and documentation function should include:

  - ➢ Tracking regional project proposals, including the reasons for their selection or non-selection. For example, in non-RTO regions using avoided cost as a metric for selection of regional projects, the ITM should monitor and document non-selection of a regional proposal caused by a TP decision to modify its local plans to eliminate the local projects that would be avoided as a result of regional alternative.

  - ➢ Tracking efforts to identify regional projects to address regional needs where no local projects are already planned. (Because most non-RTO areas use the avoided cost of displaced local projects to select projects for regional cost allocation, their Order 1000 compliance may include an alternative method for selecting projects that address a regional reliability or economic transmission need(s) for which no local projects are currently planned.)

  - ➢ Tracking of the actual cost of the local projects used in avoided-cost analyses for evaluating and selecting regional projects (e.g., to determine whether cost

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[61] *See id.*, Questions 5.a & b.

estimates for local projects are low-balled in the Order 1000 process to prevent the selection of regional projects).

- *Review and verify transmission studies, with authority to request TPs to perform additional planning studies.* Our goal is to create an ITM that provides oversight and assures meaningful consideration of regional alternatives, without requiring the creation of a full-blown independent transmission planner or dramatically increasing ITM and regional planning costs. We seek to keep the ITM role lean, as follows:

  - ➢ To perform this study review and verification role, the ITM would have access to:[62]

    - ▪ All back-up data, inputs, and models used in TP transmission studies in order to verify validity of inputs into studies and verify study results.

    - ▪ Information provided by the Enhanced Transparency process proposed by TAPS (see Part III below).

  - ➢ In each regional transmission planning cycle, the ITM will have authority to identify and formally request a defined number of planning studies (e.g., at least five, with a reopener after four years to potentially increase the number if the ITM determines five is inadequate) that it wants the TP(s) to perform. The TP(s) will conduct those studies, including appropriate sensitivity analyses, in a manner that is open and coordinated with the ITM and all stakeholders. The cost of the defined number of ITM-identified economic planning studies would be recovered as part of the overall *pro forma* Open Access Transmission Tariff ("OATT") cost-of-service.[63] These *ITM*-requested planning studies will not count toward the number of *stakeholder*-requested economic planning studies provided by existing Order 890 and Order 1000 planning processes.[64]

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[62] *Id.*, Question 5.d.

[63] *Id.*, Questions 5.a & b.

[64] There is variation among non-RTO regions as to number of stakeholder-requested economic planning studies under existing Order 1000 processes. For instance, Florida (*see, e.g.,* Florida Power and Light Company OATT, attach. K, § 8.1), Southeastern Regional Transmission Planning ("SERTP") (*Duke Energy Carolinas, LLC*, 147 FERC ¶ 61,241, P 21 (2014), *on reh'g and compliance*, 151 FERC ¶ 61,021 (2015)), and South Carolina Regional Transmission Planning ("SCRTP") (*S.C. Elec. & Gas Co.*, 147 FERC ¶ 61,126, P 45 (2014), *on reh'g and compliance*, 150 FERC ¶ 61,036 (2015)) all provide for five stakeholder-identified economic planning studies (selected by some form of regional stakeholder group). NorthernGrid provides for one stakeholder-identified regional economic planning study (with the study performed by NorthernGrid) and one stakeholder-identified local economic planning study per TP (with the study carried out by the TP). *See, e.g., PacifiCorp,* 170 FERC ¶ 61,298, PP 56-58 (2020); PacifiCorp OATT, attach. K, pt. E, § 12.2.

  - For example, no projects have ever made it to Step 5 of Florida's Order 1000 process where the avoided cost of local projects and losses are evaluated; they have all been eliminated in earlier steps. The ITM should have the authority to require additional study of such projects, so that the Commission and stakeholders fully understand the impact of *not* building them.

- *Evaluate the regional planning process and develop recommendations for improvements.* Given the post-Order 1000 track record in non-RTO regions, a critical ITM role is to identify deficiencies of the region's Order 1000 implementation (design and processes) and develop recommendations on potential ways to address them. This important ITM obligation is analogous to what the Commission recognized to be an RTO market monitor's "core function" of evaluating existing market rules and tariff provisions recommending proposed rule and tariff changes.[65]

- *Report to the Commission and all stakeholders (including states).* A periodic report (submitted at intervals proposed by each region and approved by the Commission) should provide the results of the ITM's performance of its functions. The report, which should be filed in a proceeding that invites public comment, should include:

  - The documented operation of the region's Order 1000 process (including historical performance in at least the first such report);

  - The results of the tracking of regional project proposals (including reasons for their selection or non-selection, and the actual cost of local projects used in avoided-cost analyses). This should include historical performance;

  - The results of the ITM's efforts to verify the TPs' transmission studies, including a description of the study verification process;

  - The results of any ITM-requested TP planning studies, as well as the results of any Order 1000 stakeholder-requested planning studies; and

  - Identified deficiencies of the region's Order 1000 implementation (design and processes) and the ITM's recommendations of potential ways to address them.

- *Transparency*. The ITM should be an "open book," responding to questions from stakeholders (including states and state consumer advocates) and TPs regarding the ITM's efforts, subject to Critical Energy/Electric Infrastructure Information and confidentiality requirements that should be addressed through appropriate protective agreements. While transparency is important, the intent is *not* to turn the ITM into a

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[65] *See* 18 C.F.R. § 35.28(g)(3)(ii).

> "free" consultant for these various entities, placing an unreasonable burden that would make the ITM role expansive and very costly.[66]

This baseline ITM, with its monitoring and reporting functions, is intended to advance and improve non-RTO regional planning processes, so they can more effectively satisfy Order 1000 and support whatever additional long-term regional transmission planning requirements may result from the pending *Building for the Future* NOPR.

2. Baseline ITM Mechanics in Non-RTO regions

For the baseline ITM proposed by TAPS to work effectively, key aspects of how the ITM is established need to be addressed. These include:

Selection of the ITM: The Commission should require the TPs in non-RTO regions to solicit input from stakeholders (including LSEs, states, and state consumer advocates) and, after considering such input, submit their proposed ITM to the Commission for review as part of the compliance filing process associated with any rule requiring an ITM. Interested parties would have the opportunity to intervene, protest, and comment on the compliance filing. In addition to having the expertise and capabilities to perform the ITM role, the proposed ITM must meet standards that assure it is truly independent, especially from the TPs whose procedures and conduct it would monitor. Any subsequent changes in the ITM would similarly require input from stakeholders, and filing, review, and approval by the Commission.[67]

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[66] *See Wholesale Competition in Regions with Organized Elec. Mkts.*, Order No. 719, 125 FERC ¶ 61,071, PP 446-447 (2008) ("Order 719"), *corrected,* 126 FERC ¶ 61,261, *on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009), in which, in describing the provision of information by MMUs to states, the Commission expressed concern that state commission requests for information "may place an unreasonable burden on the MMUs," and that, without limitations on the information states can request, the MMU "could rapidly become an unpaid consultant for the states."

[67] The selection process envisioned is consistent with that used for the Independent Transmission Operator ("ITO") retained by Louisville Gas & Electric Company and Kentucky Utilities Company ("LG&E/KU") to ensure continued compliance with the conditions of the LG&E/KU merger after LG&E/KU's departure

ITM Cost Recovery: The costs of a non-RTO region's ITM should be recovered as part of the TPs' overall *pro forma* OATT cost-of-service. Costs associated with the ITM should be allocated to the participating TPs on a load-ratio basis and then borne by retail and wholesale transmission load, on a load-ratio basis. The intent is that the ITM costs would be equitably shared by all load in the planning region, as is appropriate because all load should benefit from selection of more cost-effective and efficient projects through effective regional planning, which the ITM is intended to improve.

Placement: The Commission should leave it to each planning region to propose where to "house" its ITM, because there is significant regional variation in institutions among non-RTO areas. For example, the Florida Regional Coordinating Council is already tasked with retaining consultants to assist in peninsular Florida's Order 1000 process. Other regions have no such structure. The intent is to provide protections to ensure the ability of the ITM to operate independently of the TPs.

Periodic Reassessment: The Commission should periodically review the need for, role, and scope of the baseline ITM.[68]

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from MISO. *See* Order Conditionally Approving Request to Withdraw from the Midwest ISO, 114 FERC ¶ 61,282, PP 66, 80 (2006). *See also* LG&E/KU's application for approval to change its method of complying with Order 888 and 889 at 33-36, *Louisville Gas & Elec. Co. & Ky. Utils. Co.*, Docket Nos. EC06-4, ER06-20 (Oct. 7, 2005), eLibrary No. 20051012-0253. SPP originally served as ITO, and Commission approval was required to change the ITO from SPP to TranServ International. *See* LG&E/KU's application for approval to appoint TranServ International as its new ITO at 1-2, *Louisville Gas & Elec. Co. & Ky. Utils. Co.*, Docket Nos. EC98-2, ER11-4396 (Aug. 30, 2011), eLibrary No. 20110830-5090.

[68] Notice, Question 5.e.

3. Commission authority to require a baseline ITM in non-RTO regions[69]

The Commission has ample authority to require the creation and funding of a baseline ITM in non-RTO regions as an extension of its authority to require regional transmission planning. Order 1000 rests on the Commission's determination that regional transmission planning is a prerequisite to providing Commission-jurisdictional services at a just and reasonable rate.[70] Yet, in the decade since Order 1000 was enacted, no regional projects have emerged from the regional transmission planning process of any non-RTO region.[71] In affirming the Commission's authority to adopt Order 1000, the D.C. Circuit recognized that "[b]y its plain terms, Section 206 instructs the Commission to remedy 'any . . . practice' that 'affect[s]' a rate for interstate electricity transmission services 'demanded' or 'charged' by 'any public utility' if such practice 'is unjust unreasonable, unduly discriminatory, or preferential.'"[72] The court further found that "[r]eforming the practices of failing to engage in regional planning . . . involves a core reason underlying Congress' instruction in Section 206."[73]

Requiring the creation and funding of a baseline ITM that can monitor and document performance of the regional planning process in non-RTO regions, as TAPS proposes, is thus entirely consistent with the Commission's authority under section 206 to adopt reforms intended "to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power

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[69] *Id.*, Question 5.g.

[70] *See, e.g.,* Order 1000, P 47.

[71] NOPR P 39.

[72] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 55 (D.C. Cir. 2014).

[73] *Id.* at 57.

markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential."[74] It is likewise consistent with the Commission's previous recognition of the importance of an independent monitor as a tool to ensure the justness and reasonableness of wholesale market operations/transactions.[75]

B. In RTO Regions, the Commission Should Mandate Creation and Funding of a Customer Transmission Monitor to Review TOs' Annual Formula Rate Updates.

For the reasons discussed above, TAPS proposes that in RTO regions, the Commission require a Customer Transmission Monitor to review the annual inputs to formula transmission rates, funded by all load, on a load-ratio basis, through the RTO's transmission rates.[76] As noted above, these inputs receive little or no RTO review, and only limited Commission oversight. Given the anticipated transmission expansion, enhanced scrutiny of formula rate inputs is essential to containing costs and fulfilling the Commission's paramount obligation to ensure just and reasonable transmission rates. TAPS's proposed CTM is designed to be a cost-effective way to provide such needed additional review and oversight.

1. CTM Functions

TAPS proposes that for each RTO, a CTM would be retained to evaluate all TO annual formula rate updates and to participate in formula rate protocol processes, along

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[74] Order 1000, P 99.

[75] *Reg'l. Transmission Orgs.*, Order No. 2000, 89 FERC ¶ 61,285, FERC Stats. & Regs. ¶ 31,089, at 31,155-156 (1999) ("Order 2000"), *order on reh'g*, Order No. 2000–A, 90 FERC ¶ 61,201 (2000), *appeal dismissed for want of standing sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[76] Notice, Question 6.

with states and other stakeholders. We request a CTM, rather than an ITM, as the CTM's purpose is to facilitate the ability of transmission customers, states, and state consumer advocates (collectively referred to as "customer-side stakeholders") to review formula rates, on a consistent basis, to advance cost containment objectives. For this function, the CTM should have the expertise and capabilities to perform its role, but "independence" from those being charged the rates is neither necessary nor desirable. As envisioned, the CTM will not have a greater voice than others in the formula rate protocol processes.

Specifically, the CTM would be charged with reviewing the annual updates and associated supporting data, asking discovery requests, submitting informal challenges, and participating in pre-formal challenge filing negotiations.[77] It would be permitted to cooperate with stakeholders on its review and share information with them, so long as the stakeholder has executed any required confidentiality agreement associated with data provided by the TO/RTO. While the CTM would not be authorized to file its own formal challenges at the Commission, one or more customer-side parties may elect to retain (and if so, separately pay for) the CTM to support formal challenges (in lieu of or in addition to retaining and paying for their own consultant for that purpose).

The CTM should be empowered to enter joint defense agreements (or the equivalent) with transmission customers to facilitate communications with one or more customer-side stakeholders. In any case, there should be no prohibition against a stakeholder using its own consultant to assist in this process.

[77] To the extent relevant to performing its duties (e.g., to verify load data, revenues credits) and subject to appropriate confidentiality protections, the CTM should have access to raw RTO settlement systems/information that may otherwise be confidential to only the TO or individual ratepayers (e.g., load data, point-to-point transmission revenues). The CTM should have also access to the information available through the Enhanced Transparency process proposed in Part III below.

The CTM's review should include, but not be limited to, the following:

- Verify the correct (most current, Commission-approved) template was used;
- Verify financial information matches audited financials (FERC Form 1, RUS Form 12, EIA Form 412, other entity-specific annual reports that provide data in the formula rate), and that all data has been updated year-to-year);
- Verify and investigate significant year-to-year changes (e.g., greater than 20%) to inputs in operation and maintenance costs, etc.;
- Verify facilities included in the rates are eligible for recovery;
- Verify that incentives are applied properly (e.g., any Construction Work in Progress recovery has been authorized by Commission rule or individual order);
- Verify consistency in End-of-Year/Beginning-of-Year information (i.e., Beginning-of-Year information should match End-of-Year information from the previous year);
- Verify the true-up information was properly included for forward-looking test year formula rate templates;
- Verify that load information (denominator) is accurate for a pricing zone, compared to monthly billing/settlement information;
- Verify revenue credits (e.g., Uniform System of Accounts Nos. 454 and 456; from Grandfathered Agreements if applicable; etc.), compared to monthly billing/settlement information or prior year totals;
- Verify the service company costs passed-through and allocated to the operating company.[78]

2. CTM Mechanics

For the CTM to operate effectively and cost-effectively, key aspects of how the CTM is established and would operate need to be addressed. These include:

Selection of the CTM: The CTM should be selected by transmission customers, state commissions, and state consumer advocates for a three-to-five-year period. If these customer-side stakeholders cannot agree on a CTM, that region's IMM should select the

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[78] *See also* Part V.B below.

CTM, subject to Commission review, from among the candidates proposed by the transmission customers/state commissions/state consumer advocates. Major transmission owners[79] should have no voice in the selection process.

Scope: To achieve efficiencies and consistency, the number of CTMs per RTO should be limited. TAPS suggests a default of a single CTM per RTO, with some flexibility for subregional CTMs for very large, multistate RTOs where customer-side stakeholders agree that doing so would enhance effectiveness. Given cost impacts, TAPS urges against establishing CTMs on a pricing zone basis.

CTM cost recovery: The CTM should be funded by all load, on a load-ratio basis, in the RTO (or subregion, if so agreed) through the RTO transmission rates.

Periodic reassessment: The Commission should periodically (e.g., every three-to-five years) review the need for, role, and scope of the CTM.[80]

III. THE COMMISSION SHOULD REQUIRE ENHANCED TRANSPARENCY ON TRANSMISSION DEVELOPMENT AND SPENDING.

TAPS urges the Commission to revise its existing Order 890 principles to provide for enhanced transparency and information sharing,[81] modeled on the stakeholder transmission planning and asset review processes implemented by PG&E and SCE.[82]

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[79] Transmission customers that have ownership in some transmission facilities, but are primarily transmission-dependent, should not be excluded from the selection process.

[80] Notice, Question 5.e.

[81] *Id.*, Questions 1 and 2.

[82] Pacific Gas and Electric Co., Offer of Partial Settlement under Pacific Gas and Electric Company's Transmission Owner Tariff, FERC Electric Tariff Volume No. 5, Explanatory Statement at 6-9, App. IX (Stakeholder Transmission Asset Review Process), Docket No. ER19-13 (March 31, 2020), eLibrary No. 20200331-5089, *approved*, *Pac. Gas & Elec. Co.*, 172 FERC ¶ 61,142 (2020). Southern California Edison Co., Offer of Settlement at 16-18 and Exh. E (App. XII, Southern California Edison Stakeholder Review Process), Docket No. ER19-13-000, eLibrary No. 20200702-5008; Southern California Edison Company, Errata to Settlement Filing, eLibrary No. 20200702-5218; *approved*, *S. Cal. Edison*, 172 FERC

Those enhanced processes, which were developed through settlements, provide transmission customers, states, and other stakeholders with periodic, comprehensive spreadsheet reports containing detailed information on each transmission project constructed or planned by the TO. These reports have helped fill a clear information gap. Although the PG&E and SCE enhanced transparency processes have only been in place for a relatively short time, a transmission customer (TAPS member Northern California Power Agency), a transmission owner (SCE), and the California Public Utilities Commission all testified about their benefits at the October 6 Technical Conference.[83]

All TOs should be required to implement similar enhanced transparency processes that include key elements from the PG&E and SCE examples: (1) provision of a periodic, comprehensive spreadsheet report containing specific information on actual and planned transmission projects; (2) broad discovery rights for stakeholders regarding the transmission projects identified in the spreadsheet; and (3) mechanisms for stakeholders to provide feedback on planned transmission projects.

A. Periodic, Standardized Spreadsheets with Data on Transmission Projects

In both RTO and non-RTO regions, the Commission should require that every TO provide its stakeholders with a periodic, standardized spreadsheet report that lists each of the TO's actual or planned transmission projects, the total cost of which is, or is expected to be, over $1 million. All Commission-jurisdictional transmission projects above that

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¶ 61,270 (2020).

[83] Prepared Written Statement of Randy Howard, General Manager of the Northern California Power Agency (Sept. 22, 2022), eLibrary No. 20220922-5082; Opening Statement of Jeffrey Nelson, SCE, FERC Technical Conference at 6 (Sept. 16, 2022), eLibrary No. 20220916-5182; Technical Conference Tr. at 66-67 (Nelson); Summary Statement of Simon Hurd on Behalf of the California Public Utilities Commission at 5-6 (Sept. 16, 2022), eLibrary No. 20220916-5185; Technical Conference Tr. at 80 (Hurd).

cost threshold should be included, regardless of whether they are regionally planned, locally planned, or "supplemental"/"asset management" projects not currently required to be part of an Order 890 planning process. The spreadsheet report should list all construction activities for each transmission project for which there were capital expenditures in the last five years, or for which any future expenditures are anticipated in the next five years. If the total cost of the project is, or is expected to be, over $10 million, the spreadsheet should also include information on five additional years of anticipated future expenditures (i.e., for a total of ten years into the future). An updated comprehensive spreadsheet should be provided every six months.

As part of this requirement, the Commission should direct each TO to submit a compliance filing that includes a detailed Project Data Spreadsheet Template, developed after consultation with stakeholders, that identifies the specific data to be provided for each transmission project. While regional variation may be appropriate, we would expect TOs within the same region to use identical templates or justify any differences. The PG&E and SCE templates are a useful starting point.[84] Both include approximately 60 data fields containing specific information, grouped under five main headings: (1) project description; (2) TO/regional approval and related Commission rate cases; (3) permit status; (4) project status; and (5) costs. Although a few of the individual data fields are particular to California,[85] most can and should be used by all TOs. Both the PG&E and

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[84] The tariff sheets for the PG&E and SCE enhanced transparency processes include their Project Data Spreadsheet Templates. SCE's Project Data Spreadsheet Template appears on pages 10-16 of the *.pdf available at: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=0208EF4E-66E2-5005-8110-C31FAFC91712. PG&E's Project Data Spreadsheet Template appears on pages 322-329 of the *.pdf available at: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=02075EFD-66E2-5005-8110-C31FAFC91712.

[85] E.g., both the PG&E and SCE templates request information on the project's "California Public Utilities

SCE templates, for example, include data fields for: “Alternative Solutions and Costs: What alternative solutions to this project were considered? and what were the costs associated with any alternatives?”; “Primary Purpose”; “Secondary Purpose”; “Original Projected Cost or Cost Range”; “Current Projected Cost”; “Cost Cap”; and “Actual Cost.” All Project Data Spreadsheet Templates should include these and other basic data that stakeholders need to understand TO transmission plans and costs.

B. Broad Discovery Rights

The required enhanced transparency processes should also provide for broad discovery rights for transmission customers, states, and other stakeholders, subject to reasonable confidentiality protections. As noted at the October 6 Technical Conference, the right to *ask* questions is insufficient; TOs must have an obligation to *respond* to stakeholder questions.[86] In the PG&E and SCE enhanced transparency processes, discovery rights are a crucial element that have made it possible for stakeholders to obtain more detailed information on specific projects, including internal documents showing the approval process, the project’s full business case, and the alternatives and design options considered. In contrast, transmission customers in other parts of the country have struggled to obtain the information they need to understand the criteria TOs are using to prioritize and plan transmission.[87]

To be effective, the discovery rights provided by the enhanced transparency process should enable stakeholders to understand the criteria used by TOs in selecting projects, as well as their project-specific choices. Among other things, they should enable

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Commission Fire Threat Zone/Rating.”

[86] Technical Conference Tr. at 33:11-24 (McAlister, AMP).

[87] *Id.* at 32:3-22.

stakeholders to obtain detailed information on the transmission, non-transmission, and Grid-Enhancing Technologies ("GETs") alternatives considered by the TO, and the TO's estimated cost of those alternatives.

Consistent with the PG&E and SCE processes, the Commission should also require that information obtained through the enhanced transparency process—both the periodic spreadsheet reports and any materials received through discovery—may be used by recipients in any proceeding or forum, subject to reasonable confidentiality protections. Stakeholders must be able to rely on the information provided by TOs through enhanced transparency processes, including in state or federal agency and court proceedings, and in local and regional planning processes.

Depending on the amount and complexity of the information provided by TOs, it could be helpful for the ITM in non-RTO regions, or the CTM in RTO regions, to take the lead on analyzing and tracking inputs and changes to the periodic spreadsheet reports. However, the potential complications and costs associated with doing so should not discourage the Commission from at least requiring the additional transparency and broad discovery rights requested above. In any case, there should be no prohibition against a stakeholder using its own consultant to assist in this process.

C. Meaningful Stakeholder Feedback

All enhanced transparency processes must include a mechanism for meaningful stakeholder feedback. TOs should be required to not only receive, but to timely and substantively respond to, stakeholder input on asset management projects and projects subject to Order 890 or Order 1000 planning processes. As noted at the October 6 Technical Conference, even where current processes specifically allow for stakeholder input, stakeholders do not always receive a substantive response.[88] For input to be meaningful, TOs must be required to consider stakeholder input and to engage in a substantive dialogue with stakeholders.[89]

IV. OTHER CHANGES TO IMPROVE THE PLANNING PROCESS

A. RTO IMMs Should Use Their Data to Correct Planning Assumptions, Consistent with Current IMM Best Practice.[90]

As described in the SPP MMU's ANOPR Comments,[91] the SPP MMU has provided the SPP regional transmission planning process with advice on planning assumptions that conflict with the market information only the MMU has access to:[92]

> Specifically, market participants wanted to include a default \$8/MWh variable operations and maintenance adder for wind resources for planning purposes. As the independent market monitor, the MMU reviews resources' cost based offers in the energy markets daily. The MMU's experience with variable operations and maintenance adders for wind resources was inconsistent with the proposed \$8/MWh adder. As such, the MMU offered comments in the process and ultimately the adder was changed to \$0/MWh, consistent with the SPP staff proposal. The MMU's engagement was important in bringing needed market-based and independent experience to the development of an assumption in the transmission planning process.

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[88] *Id.* at 33:11-20.

[89] The PG&E and SCE enhanced transparency processes, for example, include provisions intended to foster substantive dialogue. Offer of Partial Settlement under Pacific Gas and Electric Company's Transmission Owner Tariff, FERC Electric Tariff Volume No. 5, App. IX, §§ 5.3, 5.4, 6.1-6.5 (Stakeholder Transmission Asset Review Process), *Pac. Gas & Elec. Co*, Docket No. ER19-13 (Mar. 31, 2020), eLibrary No. 20200331-5089; Southern California Edison Company's Explanatory Statement and Offer of Settlement, Ex. E, Southern California Edison Stakeholder Review Process §§ 4.4, 5.1 – 5.5, *S. Cal. Edison Co.*, Docket No. ER19-1553 (Jul. 1, 2020), eLibrary No. 20200701-5008. TAPS Initial NOPR Comments at 60-62 also highlight the need for TOs to respond to stakeholder comments in connection with the NOPR's proposed local planning process improvements.

[90] Notice, Questions 1-2.

[91] Comments of the Southwest Power Pool Market Monitoring Unit on the Advance Notice of Proposed Rulemaking at 2-3 (footnote omitted), Docket No. RM21-17 (Oct. 12, 2021), eLibrary No. 20211012-5565.

[92] *Id.* at 2-3 (footnote omitted).

Consistent with this example, TAPS suggests that the Commission direct all IMMs to follow this current best practice and use the market data that are already uniquely available to them to identify and report inconsistencies in the assumptions used in the planning process. This is a limited additional responsibility. In recommending it, TAPS is *not* seeking to expand the IMMs' role in planning beyond confirming that planning assumptions do not conflict with market data. While the SPP MMU appears to have provided advice on occasion on future cases to be studied in the planning process, [93] TAPS is *not* suggesting that IMMs be invited to take on a broader ITM-like role. As noted in Part II.B above, TAPS takes no position on whether an ITM is needed in RTO regions.

B. Other Order 890 Process Improvements

TAPS welcomes the Commission's willingness to consider improvements to local planning and processes for asset management projects.[94] As was made clear at the October 6 Technical Conference, there are significant gaps in existing processes and a strong need for additional transparency that would allow customers, states, and state consumer advocates greater insight into the planning process and greater ability to influence outcomes.[95] Improving those processes has been a long-term TAPS objective.

Collaborative, Interactive, Joint Planning: As described in the TAPS ANOPR Comments,[96] one of the most effective ways to contain costs and enable customers to

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[93] *Id*. at 3-5.

[94] Notice, Questions 1.b and 8.

[95] *See, e.g.,* Technical Conference Tr. at 56:21-57:23 (McAlister); 70:2-71:5 (O'Hagan).

[96] TAPS ANOPR Comments at 51-52. *See also id*. at 23-25, which describes and provides examples of discrimination against TDUs in the planning process. TAPS advocated for the collaborative joint planning in the lead up to Order 890. *See* TAPS Order 890 Initial Comments at 37-38, 50-52.

monitor transmission planning and spending would be for the Commission to require TOs to implement collaborative, interactive, joint planning processes. TOs should be required to invite input from affected transmission customers at all stages of the planning process (local, regional, and interregional), allow them to participate in decision-making, and assure that their views are considered on a non-discriminatory basis. Giving transmission customers a concrete decision-making role will provide them with both information they need to monitor and oversee transmission planning and spending, and invaluable insight into the justifications underlying expansion decisions. As illustrated by the Vermont Transco example,[97] joint planning can operate as a powerful cost-containment tool.

Order 890 took important steps in the right direction, but stopped short of requiring transmission providers to collaboratively develop transmission plans with customers on a co-equal basis.[98] Order 890's restrictions on the role of TDUs in local planning were a decisive factor in the rejection of a recent proposal to enhance that process, highlighting the need for further reforms.[99] The Commission's cost-containment effort provides an important opportunity to revisit and enhance these processes. Doing so would be consistent with FPA section 217(b)(4)'s directive to the Commission to exercise its "authority . . . under [the Act] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities."

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[97] *See* Part I.B above. Joint planning is a benefit associated with inclusive joint ownership arrangements. *See* TAPS Initial NOPR Comments at 9.

[98] Order 890, P 454; Order 890-A, PP 188-189.

[99] *GridLiance High Plains LLC,* 174 FERC ¶ 61,078, PP 46-47 (2021); *id.* Clements, Comm'r, concurring (highlighting the need for more effective local transmission planning processes to ensure cost-effective solutions are selected and infrastructure money is well spent by customers).

Reexamining the scope of the Order 890 process: In its *Building for the Future* ANOPR and NOPR comments, TAPS has urged reevaluation of the limitations and exclusions from the scope of the Order 890 planning process.[100] As noted in Part I.A above, TAPS supports and urges expansion of the NOPR's right-sizing proposal for replacement projects. However, that still leaves important aspects of local planning—"asset management projects and activities [that] do not expand the grid"—outside Order 890 requirements.[101] Given growing concerns about aging infrastructure, exclusion of such projects from a full Order 890 process, with regional review, cannot be justified on the ground that "Order No. 890 [reforms] were intended to address concerns regarding undue discrimination in grid expansion,"[102] ignoring the impact of such projects on just and reasonable rates to consumers and the potential for discrimination.

Transparency: TAPS's enhanced transparency proposal (*see* Part III above) is intended to improve customer, state, and state consumer advocate access to information that could be crucial to cost containment efforts with respect to a wide range of planned projects. It is also essential to making the planning processes required by the Commission effective. Thus, the Commission should ensure that stakeholders have transparency on all planned projects, including asset management projects, and a window into why a particular project was selected or prioritized. If a TO considered alternatives, it should

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[100] *See* TAPS Initial NOPR Comments at 67; TAPS ANOPR Comments at 25.

[101] *See S. Cal. Edison Co.*, 164 FERC ¶ 61,160, P 31 (2018) ("*S. Cal. Edison*"), *reh'g denied*, 168 FERC ¶ 61,170 (2019); *Cal. Pub. Utils. Comm'n v. Pac. Gas. & Elec. Co.*, 164 FERC ¶ 61,161, P 66 (2018) ("*Pac. Gas & Elec*"), *reh'g denied* 168 FERC ¶ 61,171 (2019). Even where the Commission enforced an RTO-specific requirement that individual TOs planning for such "Supplemental Projects" adhere to Order 890 requirements, no RTO review of those TO plans was required. *See Monongahela Power Co.*, 162 FERC ¶ 61,129, P 72, *reh'g denied*, 164 FERC ¶ 61,217, P 117 (2018).

[102] *S. Cal. Edison*, P 31.

provide documentation for those alternatives, their estimated costs, and the reason(s) they were not selected.

Substantive response requirement: Planning process reforms are needed to ensure that TOs not only allow stakeholder input, but also substantively respond to that input. As noted in Part I.A above, TAPS has stressed the need for a substantive response requirement in commenting on the *Building for the Future* NOPR's proposed three-meeting regional process for review of local plans. And a substantive response requirement is an important element of TAPS's enhanced transparency proposal, described in Part III.C above. To better ensure that the planning process actually "provide[s] for the timely and meaningful input and participation of customers into the development of transmission plans" as Order 890 intended,[103] the Commission should more generally reform the Order 890 planning process to expressly include a substantive response requirement.

V. IMPROVEMENTS TO THE FORMULA RATE PROCESS[104]

A. The Commission Should Explicitly Adopt the MISO Transmission Formula Rate Protocols as a Standard.

When a TO seeks Commission approval of a formulaic mechanism to calculate a revenue requirement or a rate, formula rate protocols—which provide customers with "specific procedures for notice of, review of, and challenges to the rates that they will be

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[103] Order 890, P 454. *See also* Technical Conference Tr. at 33:7-33:24 (McAlister, arguing that "an arbitrary set of meetings and days and opportunities to comment," without an opportunity for actual back-and-forth discussion, doesn't provide stakeholders a "meaningful opportunity" to offer input, and that "to really have a meaningful opportunity to have a back and forth . . . [t]here has to be some actual requirement that the transmission owners respond.").

[104] Notice, Question 6.a.

charged"[105]—are a critical component of the filed rate.[106] The Commission has emphasized the importance of formula rate protocols in numerous proceedings,[107] and expended significant effort to develop guidance for the provisions that formula rate protocols should, at minimum, contain. In 2012, the Commission undertook a detailed review and investigation of the formula rates used in the MISO Tariff in Docket No. EL12-35 ("MISO Protocol Proceeding"). Following an initial order seeking comments,[108] the Commission found that the MISO Protocols were deficient because they did not establish the scope of public participation, provide transparency, or a dispute resolution process.[109] After multiple rounds of compliance filings, the Commission accepted a set of protocols for the MISO Tariff.[110]

The Commission has applied the lessons learned in the MISO Protocol Proceeding in numerous "show cause" orders.[111] Those orders analyzed other utilities' protocols "using the standards" of the MISO Protocol Proceeding orders,[112] in many

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[105] *Commonwealth Edison Co.*, 182 FERC ¶ 61,156, P 3 (2023) ("*ComEd*") (citing *Black Hills Power, Inc.,* 148 FERC ¶ 61,035, P 4 (2014)); *see also Pub. Serv. Co. of Colo.*, 179 FERC ¶ 61,057, P 3 (2022) ("*PSCo*") (same).

[106] *Black Hills Power*, P 3 (finding that protocols are a key tool to making a rate just, reasonable, and not unduly discriminatory).

[107] *See, e.g., ComEd*, PP 2-3; *see also PSCo*, PP 2-3.

[108] *Midwest Indep. Transmission Sys. Operator, Inc*., 139 FERC ¶ 61,127 (2012) (subsequent history omitted).

[109] *Midwest Indep. Transmission Sys. Operator, Inc*., 143 FERC ¶ 61,149 (2013), *order on reh'g*, 146 FERC ¶ 61,209 (2014) (subsequent history omitted).

[110] *Midwest Indep. Transmission Sys. Operator, Inc*., 146 FERC ¶ 61,212 (2014), *order on reh'g*, 150 FERC ¶ 61,024, *order on compliance*, 150 FERC ¶ 61,025 (2015).

[111] *See, e.g., ComEd*, P 5; *see also PSCo*, P 5.

[112] *Id.* In another instance, the Commission required modifications to formula rate protocols notwithstanding the fact that the Commission had just accepted a settlement that included the settling parties' preferred protocols. *Empire Dist. Elec. Co.*, 150 FERC ¶ 61,200, P 12 (2015).

instances quoting the relevant MISO Protocol provision for comparison.[113] Thus, the MISO protocols are the *de facto* standard by which the Commission reviews formula rate protocols.

Many currently effective formula rates, however, include protocols that materially differ from the MISO Protocols. For example, some include information exchange periods as short as 30-120 days. By comparison, the MISO Protocols provide six months to submit information requests. The MISO Protocols period should be viewed as a minimum. The resolution of many formula rate issues may require multiple rounds of information requests, as well as informal meetings between subject matter experts to enable the parties to understand and resolve issues. This is especially true for formula rate issues that involve the intersection of tax law, accounting, and ratemaking (e.g., those involving income tax rate changes), which can be extraordinarily complicated.

Another important area in which some protocols are deficient is the period between the close of discovery and the due date for informal challenges. In general, the MISO Protocols provide Interested Parties more than 30 days to review responses to discovery prior to the deadline for informal challenges. In contrast, some protocols require such challenges to be made just one week after TO responses. The short turnaround generally leads to a "kitchen sink" approach to informal challenges to avoid omitting any potentially valid claims, which can waste all parties' time and money. Even worse, the haste can lead to an unintended omission of important issues.

This same timing issue arises with respect to formal challenges. To increase the likelihood of resolving informal challenges, protocols should not force parties to

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[113] *Id.* P 16 & n.40.

prematurely file their dispute with the Commission. The MISO Protocols require Interested Parties to submit informal challenges, provide for a TO response, and then provide a 45-day negotiation period before an Interested Party must file a formal challenge. In addition, the TO may extend the negotiation period. As a result, hard deadlines do not prematurely end discussions. In contrast, some formula rates require the filing of a formal challenge by a fixed date.

To the extent protocols inferior to the MISO Protocols remain in place, the Commission should act to reduce the burden on customers of getting them updated to the MISO standard. Specifically, TAPS urges the Commission to adopt a policy that, on complaint by an Interested Party that includes a preliminary showing that a TO's protocols are inferior to the MISO Protocols in some respect(s), the Commission will either: (1) grant the complaint and require a corrective compliance filing by the utility; or (2) issue a show cause order requiring the TO to either modify its protocols or explain why they remain just and reasonable. TAPS is not seeking a generic order that all protocols meet or exceed (from a customer point of view) the MISO Protocols. There may be many reasons such protocols remain in place. For example, parties may have built a very constructive relationship, leaving customers content with the existing protocols. Rather, the Commission should impose that requirement when it learns that current protocols deviate from the MISO standard in a manner that could harm consumers.

B. The Formula Rate Protocols Should Be Expanded to Provide Access to Affiliated Service Company Data When Service Company Costs are Included in the Rate.

The Commission has been very clear that transparency is critical to a finding that a formula rate is just and reasonable. In the MISO Protocols Proceeding, the Commission identified three prongs of inquiry as to deficiencies, the second of which was the transparency of the information exchange.[114] Subsequent "show cause" proceedings summarized the Commission's concern with the pre-existing MISO protocols:[115]

> The Commission stated that the annual update should include underlying data and calculations supporting all inputs that are not supported in the FERC Form No. 1 and provide information about the transmission owner's implementation of the formula rate in sufficient detail and with sufficient explanation to demonstrate that each input to the formula rate is consistent with the requirements of the formula rate.

For a formula rate to be just and reasonable, customers and Interested Parties must have full access to the data used to calculate rates. It is especially important for customers to have access to data that are not available in the FERC Form 1.

In recent years, utility operating companies ("OpCos") have increasingly used affiliated service companies ("ServCos") to provide services that were formerly performed by the OpCo. While there is nothing inherently wrong with subcontracting—particularly if it saves consumer money—an Interested Party seeking information to challenge the OpCo's cost of the service will often receive only the ServCo's invoice to the OpCo. Without the additional cost support that would be available on request if the OpCo had provided the service directly, the Interested Party cannot verify that ServCo costs included in OpCo rates are reasonable.[116] And because the ServCo is an affiliate,

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[114] *Midwest Indep. Transmission Sys. Operator, Inc*., 139 FERC ¶ 61,127, P 8.

[115] *PSCo*, P 17.

[116] *See, e.g.,* Protest and Request for Rejection; or in the Alternative; Request for Suspension, Refund Effective Date, and Evidentiary Hearing and Settlement Judge Proceedings by the Maryland Office of People's Counsel, the New Jersey Division of Rate Counsel, Old Dominion Electric Cooperative, and Philadelphia Area Industrial Energy Users Group at P 36, *Atl. City Elec. Co., Delmarva Power & Light Co., PECO Energy Co., PJM Interconnection, L.L.C.,* Docket No. ER21-2965 (Oct. 20, 2021), eLibrary No. 20211020-5182 (explaining why Interested Parties must have access to ServCo data to understand

the ServCo-OpCo transaction is not at arms-length, and it cannot be assumed the OpCo is proactively managing costs from the ServCo.

To ensure the needed transparency, the Commission should establish a general requirement that, when an OpCo uses an affiliate to perform a service with costs that are included in a formula rate, the OpCo must, in response to an information request of an Interested Party: (1) obtain the requested data and information from its affiliate; and (2) provide the data and information to the Interested Party as if the OpCo had performed the service itself. The Commission has already accepted formula rate protocols that include such provisions. Duke Energy Carolinas LLC, for example, submitted a filing[117] in September 2022, proposing changes to the formula rate template and protocols applicable to the Duke Energy Florida, LLC ("DEF") region. The filing, which the Commission has accepted,[118] implemented DEF's plan to use a separate, but affiliated, company to purchase utility property and then lease the property to DEF. It included formula rate protocol language that explicitly protected the right of Interested Parties to obtain the information necessary to review all costs included in formula rate calculations:[119]

> With regard to the DEF Procurement Company ("ProCo"), DEF and ProCo have received approval to use consolidated accounting and, consequently, will present a consolidated FERC Form 1. Nonetheless, DEF shall make such information available to interested parties about ProCo's

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costs included in formula rate calculations).

[117] Revisions to Joint Open Access Transmission Tariff, *Duke Energy Fla*., Docket No. ER22-2844 (Sept. 13, 2022), eLibrary No. 20220913-5132 ("Revisions to Joint Open Access Transmission Tariff").

[118] *Duke Energy Carolinas*, *Order Accepting Tariff Revisions Subject to Condition*, 181 FERC ¶ 61,216 (2022).

[119] Revisions to Joint Open Access Transmission Tariff, Filing Letter at 7-8.

> books and records as necessary to ensure that the existence of ProCo does not diminish interested parties' rights under these Protocols about matters related to rates calculated hereunder. DEF shall not use the existence of ProCo as a basis to resist rate inquiries that would be valid under these Protocols in the absence of ProCo.

While the Commission may not have authority to compel information production by an entity that is not a utility, it has the authority and obligation to ensure that affiliate costs an OpCo seeks to include in a formula rate are properly supported and that formula rates are transparent. Accordingly, the Commission should make clear that while an OpCo is free to purchase services from affiliated companies, it retains the full obligation to support costs included in a formula rate, and a ServCo invoice is insufficient. In sum, OpCos must ensure that customers may fully review data and information supporting costs included in a formula rate when a service is provided by an OpCo affiliate.

C. Formula Rate Protocols Should Have Discovery Dispute Resolution Provisions that Include Access to a Discovery Master Appointed by the Commission.

The production of information by a TO is the most important aspect of formula rate protocols. Without information, a formula rate is not transparent, vitiating the opportunity to challenge inputs to the formula. Access to information must also be timely; delayed production of data will erode the ability of an Interested Party to review and challenge formula rate updates. While we recognize that the Commission has previously denied customer requests to include in protocols a provision that allows for appointment of a FERC Administrative Law Judge as a Discovery Master,[120] given the increasing recognition of the importance of formula rate protocols to contain growing

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[120] The Commission rejected a requirement for a discovery master provision in the MISO Protocols orders. 143 FERC ¶ 61,149, P 122.

transmission costs, now is the time for the Commission to ensure that information access rights contained in protocols are real.

Customers and other Interested Parties have experienced, and continue to experience, difficulty obtaining information from utilities on formula rate matters.[121] That such disputes have been infrequently brought to the Commission does not mean they do not exist. To the contrary, that is more attributable to the general absence of formula rate protocol provisions for bringing such disputes to the Commission, and the heavy burden on customers of initiating two formal challenges to address any suspected issue in those circumstances—one to obtain data, and a second if the data reveal a problem.

A Discovery Master could stop a non-cooperative TO from erecting steep barriers to identification of abuses of a formula rate. And just the availability of a Discovery Master may well deter TOs from delaying or withholding information, even without resorting to the Discovery Master.[122]

Thus, the Commission should require that formula rate protocols provide for the appointment of a Discovery Master.

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[121] While not pertaining to discovery, *Kan. Elec. Power Coop. v. Evergy Kan. Cent., Inc*., 179 FERC ¶ 61,162, *set aside*, 181 FERC ¶ 61,017 (2022), illustrates a filing to address Evergy's refusal to engage in good faith negotiations regarding informal challenges. Moreover, the behavior at issue before the Commission was the second time a formal challenge and complaint had to be brought. *Id.* P 41 & n.75.

[122] This is consistent with TAPS member experiences with protocols that include such a provision. For example, the AEP formula rate included in the PJM Interconnection, LLC ("PJM") Tariff contains provisions for the appointment of a Discovery Master, but that provision has not needed to be invoked. PJM Tariff, Att. H-14A, section 4(i) (providing that an "Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules."). Similarly, section 2.1(d) of the Oklahoma Gas & Electric protocols (SPP Tariff, Att. H-2B) and section 4(i) of the protocols used by AEP's SPP affiliates (SPP Tariff, Att. H, Add. 4, Pt. 2) provide for petitioning for appointment of a Discovery Master, but Interested Parties have not needed to seek appointment of a Discovery Master.

CONCLUSION

The Commission should take these comments into account as it considers next steps in this critical effort to contain costs associated with the anticipated expansion of the transmission grid to accommodate the changes in our resource mix.

Respectfully submitted,

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