UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act	Docket No. RM20-10-000

COMMENTS OF TRANSMISSION ACCESS POLICY STUDY GROUP

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TABLE OF CONTENTS

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The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to comment on this Notice of Proposed Rulemaking ("NOPR").[1]

EXECUTIVE SUMMARY

TAPS strongly urges the Commission *not* to move forward with the proposed rule. There is no need to dramatically increase return on equity ("ROE") incentives to spur investment in transmission. The NOPR's finding as to the robustness of transmission investment[2] is confirmed by overwhelming evidence that the Commission's existing policies, which since the 2012 Policy Statement[3] have focused on non-ROE incentives, have been highly successful in promoting transmission investment and are expected to continue to do so. It fails to justify adding up to 250 basis points for project-based incentives and a doubled regional transmission organization ("RTO") adder never mentioned in its "need for reform" discussion.

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[1] 170 FERC ¶ 61,204 (2020), *corrected*, 171 FERC ¶ 61,072 (2020); Statement by Commissioner Glick dissenting in part, issued on March 25, 2020, eLibrary No. 20200325-3084 ("Glick Dissent"); Errata Notice, issued April 24, 2020, 171 FERC ¶ 61,072 (2020).

[2] NOPR P 26.

[3] *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 (2012) ("2012 Policy Statement").

The proposed reforms to project-based incentives are unlawful. Far from aligning incentives to Section 219, 16 U.S.C. § 824s, as claimed, the NOPR strays from Congress' directive. It proposes to abandon the current approach, which requires applicants to demonstrate ROE incentives are needed, after applying non-ROE incentives, to address risks and challenges not accounted for in the base ROE. Instead, the NOPR would grant enormous benefits-based ROE incentives, a '"bonus' for good behavior" that the Commission has rightly and expressly rejected.[4] It ignores Section 219's focus on incentives that "promote" investment which, in conjunction with its overarching directive that resulting rates must be just and reasonable, requires limiting incentives to those needed and no more than needed to induce the desired action. The NOPR's incentives would undermine the Order 890[5] and 1000[6] planning processes that the Commission, acting under Section 206, 16 U.S.C. § 824e, found necessary for transmission rates to be just and reasonable, and would violate its Section 217, *id.* § 824q, obligations. And handing out abundant "FERC candy," including to projects that go above and beyond what is required for an adequate level of reliability with no consideration of the project's cost, threatens to mobilize opposition to siting, increasing the greatest risk facing developers and thwarting the purpose of Section 219.

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[4] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, 116 FERC ¶ 61,057, P 26, ("Order 679"), *on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *clarified*, 119 FERC ¶ 61,062 (2007).

[5] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 ("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).

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), *reh'g denied*, Order No. 1000-A, 139 FERC ¶ 61,132, *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 moving away from risks and challenges, the NOPR appears to abandon, without so much as a mention, the 2012 Policy Statement's encouragement of joint ownership as a risk-reducing measure that ROE incentive applicants should consider.[7] Joint ownership with public power brings together Section 219(b)(1)'s goal of promoting grid investment "regardless of the ownership of the facilities," and Section 217(b)(4)'s, *id*. § 824q(b)(4), directive to "facilitate[] the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities." Inclusive joint ownership arrangements, which have a strong track record in getting needed transmission built and whose value the Commission repeatedly recognized as advancing Section 219's goals, should continue to be promoted. Regardless whether it otherwise alters its approach to incentives, the Commission should maintain or enhance the inducement to joint ownership. An applicant that has not provided a meaningful opportunity for joint ownership on a load-ratio-share basis to transmission-dependent utilities ("TDUs") in the footprint that will bear the cost of the facility, should face a rebuttable presumption that it has *not* taken all appropriate steps to minimize its risks, and that granting the incentive does not accord with the Federal Power Act ("FPA"). TAPS suggests various other means to induce joint ownership consistent with the NOPR's incentive approach.

Other elements absent from the NOPR are necessary, but not sufficient (without addressing foundational flaws), for benefits-based incentives to be consistent with Section 219. TAPS urges that these overarching requirements be applied to all such incentives:

[7] 2012 Policy Statement P 24 & n.33.

- Extra profits should not be awarded for doing exactly what TOs are otherwise required to do. Benefits-based ROE incentives should be reserved for exemplary, voluntary projects.

- To be considered, benefits must be clearly defined and quantified.

- Benefits-based incentives must take greater account of actual costs to ensure consumers benefit. And the Commission should maintain its prohibition on application of incentives to cost overruns.

- Life-of-unit benefits-based incentives are not just and reasonable. If not limited to ten years or less, accountability is required, with ROE incentives terminated or reduced if projected benefits do not materialize or are not sustained.

- The Commission should mitigate the damage benefits-based incentives would inflict on transmission planning processes that it has worked hard to develop. And to avoid such ROE incentives becoming a vehicle for monopoly rents, competitive opportunities with respect to projects for which an incumbent TOs seeks benefit-based incentives should be expanded, by requiring waiver of all applicable federal and state rights of first refusal as a prerequisite for incentives (absent meaningful opportunities for joint ownership).

- The proposal to maintain existing procedures for incentives premised on evaluation of benefits—highly fact- and assumption-based inquiries—is inconsistent with just and reasonable rates. Disclosure requirements must be an essential part of the application process, and the Commission must provide a meaningful opportunity for evidentiary hearings (with discovery).

As a supplement to these requirements, TAPS urges adoption of specific protections if the Commission allows **economic-benefit-based ROE incentives** not needed to attract capital investment for projects likely to be built in any case:

- Require full participation and selection in applicable planning processes as a prerequisite, and base economic-benefit estimates on modeling and assumptions consistent with Order 1000 processes for selecting economic projects.

- Base Economic Incentives on *actual* costs, not cost estimates, absent a fully inclusive cost containment commitment. If *ex ante* incentive awards are not completely barred for other developers, they should be made provisional on a Section 205, 16 U.S.C. § 824d, filing that includes the project's final, *actual* costs and confirms that it still achieves the benefit-cost ratio used in the original award.

- Require *all* actual costs be included in *ex post* benefit-cost evaluations, as well as in actual-cost confirmations of *ex ante* benefit-cost evaluations. If exclusions for factors "beyond a developer's control" (NOPR P 60) are allowed at all, they should be restricted to developers that take all appropriate steps to avoid cost overruns from such unexpected factors. A limited exclusion for excess costs associated with state siting difficulties might be appropriate *if* the developer reduced siting risk by offering inclusive joint ownership, given its strong track record of facilitating siting.

- Require all benefit-cost evaluations include contemplated incentives, to avoid "bait and switch" and destruction of Order 1000's competitive transmission development process. Failure to make, at the time projects are submitted for consideration in the planning process, a binding declaration of the specific incentives reserved would waive the right to request them.

- Raise the proposed benefit-cost thresholds to at least the 90th percentile (an A- rather than just a C+), calculated using a one-way ratchet to assure that the standards for awarding incentives are not diminished over time.

- Impose process, disclosure, and evidentiary requirements necessitated by reliance on data- and modeling-intensive quantitative metrics to award incentives.

- Particularly in non-RTO areas and for local transmission projects, address discrimination in the implementation of benefits-based incentives by ensuring that the project's economic benefits flow to the entire footprint required to pay for those adders, and not just the incumbent TO's retail customers.

The NOPR's proposed **Reliability Incentives** clearly violate Section 219 and should not be adopted. These incentives are not needed to "promote" investment above and beyond an adequate level of reliability; TOs are already highly incentivized to over-invest in facilities on which they are assured cost recovery plus a Commission-regulated ROE. Among other deficiencies, the proposed incentive does not even consider a project's cost, offers no discernable standard for evaluating whether a project's reliability benefits are significant and demonstrable, and encourages TOs to degrade reliability to later qualify for incentives. If the Commission nevertheless allows such incentives, it should, as a supplement to the general requirements:

- Clarify that projects designed to maintain an adequate level of reliability, and therefore *in*eligible for above-and-beyond ROE incentives (NOPR P 64), include those undertaken, consistent with good utility practice required by tariff, to comply with NERC standards and applicable planning criteria. A narrower definition would conflict with the Commission's long-standing interpretation of reliability projects and well-established industry practice.

- Evaluate only the incremental benefits provided above and beyond whatever project would have been required to meet reliability needs and apply any incentive only to the incremental costs above what it would have cost to build a project that maintains an adequate level of reliability. To do otherwise would grant incentives the NOPR correctly recognizes as unnecessary.

- Require an applicant demonstrate that a project's quantifiable above-and-beyond reliability benefits significantly exceed its incremental cost, using standardized metrics and judged against a benchmark benefit-cost ratio, so only exemplary projects are rewarded with additional equity returns.

- Require that, to be eligible for the incentive, a project be vetted in an Order 890 planning process, and (as in the case of Economic Incentives) that the applicant waive all state and federal rights of first refusal ("ROFRs") to foster competition.

- Favorably consider meaningful offers of inclusive joint ownership, particularly if accepted, as evidence that the project is not gold-plating and provides significant benefits to the system as a whole.

- Prevent double-counting of benefits by requiring that a project that qualifies for the Economic Incentive will not be eligible for the Reliability Incentive, and do not grant Reliability Incentives for an entire transmission project based on the addition of technology.

- Subject incentive applications to an evidentiary hearing, with discovery, to evaluate the claimed benefits and to assess the project's prudence.

The proposal to grant additive incentives for overlapping and poorly defined benefits, on top of an unjustifiably doubled RTO adder, is made worse by its **proposed 250 basis point cap** that accommodates, rather than restricts, such excessive incentives and by elimination of the zone-of-reasonableness limitation. To meet FPA obligations, a fixed cap no higher than 100 basis points of project-specific adders, plus no more than 50 basis points for RTO participation, along with a zone of reasonableness restriction, should be imposed, with no relaxation of the cap on previously granted incentives.

While TAPS supports case-by-case application of **non-ROE incentives**, we oppose the NOPR's proposed elimination of both the nexus test as a limitation on these incentives and the requirement that the total package of incentives must be tailored to the risks and challenges of the particular project not accounted for in base return ROE.

TAPS supports elimination of the **Transco Adder**, and urges its elimination for existing Transcos, which the NOPR finds to have failed to produce superior levels of transmission investment on a sustained basis. Continuation would be patently unjust.

TAPS strongly opposes the NOPR's unjustified doubling of the **RTO Adder** as contrary to the FPA's requirement that an incentive must be set at the level needed to induce the desired conduct and no higher. The impact of the current 50 basis point adder on businesses and consumers is enormous—roughly $400 million per year and growing.[8] Doubling the adder, and applying it to increasing transmission investment, will bring that closer to $1 billion per year. This drastically increased burden is not needed to induce TOs to join RTOs that currently operate the grid serving at least two-thirds of the nation's load and that already offer a significant range of benefits and market opportunities to induce TO participation. The RTO adder should be maintained at no higher than its current 50-basis-point level and limited to no more than ten years from a TO's initial RTO participation, consistent with Section 219(c)'s mandate to provide an incentive *for joining* an RTO. The NOPR's unlawful elimination of the FPA's voluntariness requirement as applied to the RTO adder should be rejected.

While the NOPR rightly does not propose the highly problematic shared-savings incentives, its proposed **incentives for deployment of transmission technologies** needlessly increase cost without addressing the real obstacles to deploying new

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[8] *See* Part X.A.

technologies. A better approach would be to integrate advanced technologies into Order 890 and Order 1000 processes. If the Commission nevertheless proceeds, it should:

- Narrow the NOPR's definition of "Eligible Transmission Technologies," so the incentive is tailored to new cutting-edge technologies, not virtually anything that's not a wire or substation.
- Clarify the NOPR's vague proposal to apply a benefit-cost threshold to the Technology Incentive and modify it to appropriately ensure that only exemplary advanced technologies are awarded incentives.
- Clarify that technology benefits cannot be double-counted to justify awarding multiple types of ROE incentives for the same technology investment.
- Eliminate the proposed rebuttable presumption that pilot programs will be eligible for the Technology Incentive, and instead adopt measures to better promote pilots.
- Refine the NOPR's annual reporting requirement so the duration can be tailored to assure the filings are useful and serve their intended purpose.

Finally, the proposed changes to Form 730 are important improvements, but timeframe and scope should be expanded.

In short, the Commission should *not* move forward to a final rule, but if it does it should adopt TAPS proposals to better align the NOPR to the Commission's obligations.

INTEREST OF TAPS

TAPS is an association of TDUs in more than thirty-five states promoting open and non-discriminatory transmission access.[9] Representing entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS has long recognized the need for a robust transmission infrastructure to provide non-discriminatory transmission access and foster competition, thereby enabling TAPS members to meet their load reliably and affordably. As TDUs, TAPS members pay

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[9] David Geschwind, Southern Minnesota Municipal Power Agency, chairs the TAPS Board. Jane Cirrincione, Northern California Power Agency, is TAPS Vice Chair. John Twitty is TAPS Executive Director.

transmission rates that are substantially increased when the Commission approves above-cost incentives, and participate, when possible, in transmission development projects.

TAPS has participated actively in numerous Commission proceedings concerning transmission planning, pricing, and incentives policies, including those underlying Order 679 and the 2012 Policy Statement. TAPS has supported use of risk-reducing incentives, rather than cost-increasing incentives, and use of the Commission's incentive policy to encourage inclusive joint ownership arrangements, which have a track record of getting transmission built that meets the needs of all load-serving entities ("LSEs") that rely on the grid, consistent with the mandate of FPA Section 217(b)(4).

TAPS submitted extensive comments in the Notice of Inquiry that laid the groundwork for the instant NOPR,[10] and it sponsored a panelist and submitted follow-up comments in the related Grid Enhancing Technologies Workshop.[11]

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[10] *See* Initial Comments of TAPS, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 6, 2019), eLibrary No. 20190626-5264 ("TAPS Initial NOI Comments") and Reply Comments of TAPS, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (Aug. 26, 2019), eLibrary No. 20190826-5116 ("TAPS Incentives NOI Reply Comments").

[11] Prepared Statement of Steven Leovy on Behalf of WPPI Energy and the Transmission Access Policy Study Group for the November 5-6 Workshop, *Grid Enhancing Technologies*, Docket No. AD19-19-000, (Nov. 12, 2019), eLibrary No. 20191112-4023 ("Leovy Statement"); Post-Workshop Comments of TAPS, *Grid Enhancing Technologies*, Docket No. AD19-19-000 (Feb. 14, 2020), eLibrary No. 20200214-5154 ("TAPS GETs Post-Workshop Comments").

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COMMENTS

I. THE NOPR FAILS TO SUPPORT THE NEED FOR ITS PROPOSED REFORMS

The NOPR's changes could not be more fundamental, altering both the basis on which incentives are to be granted and their magnitude. On project-based incentives, the NOPR would abandon Order 679's risks-and-challenges approach, as refined by the 2012 Policy Statement's emphasis on risk-reducing incentives and risk-reduction measures, which spurred massive and sustained transmission investment (despite the rarity of ROE incentives). Instead, the NOPR would grant additive project-based incentives based on Commission evaluation of various claimed benefits, without any demonstration of nexus—i.e., that the requested incentive is tailored to what is needed to get the project built. ROE incentives would operate as a "bonus for good behavior," an approach that Order 679 expressly and rightly rejected.[12] Non-ROE incentives would continue to be available on a case-by-case basis, but without anchoring them in the nexus test or

[12] Order 679, P 26.

requiring assessment of the impact of their availability on the reasonableness of the total package of incentives granted. And the RTO participation incentive would be doubled to 100 basis points, a step very few commenters even suggested.[13]

As a result of these and other proposed changes, the NOPR would move from an era in which ROE incentives were largely limited to 50 basis points for RTO participation, to a regimen where up to 250 basis points of ROE incentives will be commonplace, without consideration of whether the incentives are needed or even helpful in getting transmission built. In doing so, without even acknowledging the change, the NOPR fails to retain any inducement for joint ownership with public power entities that the Commission has long recognized as instrumental to achieving Section 219's goals.

To justify these dramatic and costly reforms, it would be reasonable to expect a demonstration that existing incentives have been inadequate to prompt needed investment. But the NOPR offers none. Rather, the NOPR (P 26) concedes "transmission infrastructure development has remained generally robust at the aggregate level." *See also id.* P 31 ("we are encouraged by the investment in transmission infrastructure to date"). These concessions are not surprising given the compelling record of the success of the Commission's existing policies in turning around the situation that prevailed at the time Congress enacted Section 219, when the country had faced a significant decline in

[13] Most proponents of continuation of an RTO Adder sought to maintain the current level. Even AEP, one the very few commenters even suggesting a basis for some increase in the adder did not urge that it be doubled. Comments of American Electric Power Co. 2, 12-13, *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Docket No. PL19-3-000 (June 26, 2019), eLibrary No. 20190626-5171.

transmission development since 1975 notwithstanding a doubling of load, and load was expected to continue to grow 50% over the next two decades.[14]

Today's situation is completely different. Existing incentives policies have worked, together with other initiatives, to induce sustained and robust transmission investment (even after the 2012 Policy Statement limited ROE incentives), as documented in TAPS' Notice of Inquiry ("NOI") Comments[15] and confirmed by numerous others,[16] including Edison Electric Institute ("EEI"),[17] the Brattle Group,[18] and Commission Staff.[19] The Energy Information Administration graphically depicted that "[s]pending on infrastructure to deliver power to homes and businesses has increased steadily over the past 10 years," in charts showing dramatic transmission increases on a

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[14] Order 679 P 10.

[15] TAPS Initial NOI Comments at 14-22.

[16] See TAPS Incentives NOI Reply Comments at 6-9.

[17] *Historical and Projected Transmission Investment*, EEI (Oct. 2018), http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf (investor-owned electric companies and stand-alone transmission companies invested over $116 billion in transmission between 2012 and 2017, and expect to invest another $89 billion between 2018 and 2021).

[18] Johannes P. Pfeinfenberger, et al., *Transmission Competition Under FERC Order No. 1000: What We Know About Cost Savings to Date*, Brattle Group, 6 (Oct. 25, 2018), https://brattlefiles.blob.core.windows.net/files/14786_brattle_competitive_transmission_wires_10-25-18.pdf ("Brattle Group Order 1000 Discussion Paper") ("U.S. transmission investments have stabilized" at approximately $20 billion per year between 2013 and 2017, after rising steadily from $2 billion per year in the 1990s).

[19] 2017 Transmission Metrics 5 (Oct. 6, 2017), eLibrary No. 20171006-3021 ("2017 Transmission Metrics Report") ("Load-weighted transmission investment averaged $2.43 per megawatt hour (MWh) of retail load for all North American Electric Reliability Corporation (NERC) regions between 2008 and 2015, up from a load weighted average of $2.19 per MWh of retail load between 2008 and 2014 in the 2016 Report.").

national and regional basis.[20] This new investment is confirmed by steep transmission rate increases borne by customers.[21]

There is good reason for the eagerness to invest in transmission under the Commission's existing policies. Few other investments offer the assurance of cost recovery through formula rates that include a Commission-regulated ROE,[22] with the opportunity for project-specific incentives if warranted, plus an RTO adder. Investors have touted these investments' "recession-resistant earnings."[23] No wonder TOs highlight increasing transmission investments when communicating with investors,[24] and fight for the right to build transmission and exclude competitive developers.[25]

Where regions have adopted a competitive solicitation or bidding process to comply with Order 1000, competition has been robust. Developers have sharpened their

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[20] U.S. Energy Information Administration, *Utilities Continue to Increase Spending on Transmission Infrastructure*, Today in Energy (Feb. 9, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34892. *See also* impressive regional statistics collected in TAPS Initial NOI Comments at 15-16.

[21] *See* TAPS Initial NOI Comments at 17 (documenting staggering transmission rate increases experienced under existing incentives policies).

[22] Some states provide direct pass-through, via a retail transmission delivery charge, of transmission costs subject to this Commission's jurisdiction. *See, e.g.*, Kan. Stat. Ann. § 66-1237(c).

[23] Warren E. Buffet, *Berkshire's Performance vs. the S&P 500*, Berkshire Hathaway Inc., 12 (Feb. 25, 2017), http://www.berkshirehathaway.com/letters/2016ltr.pdf (essentiality of electricity service and steady demand as ensuring Berkshire Hathaway Energy's ability to service debt under all circumstances).

[24] *See* Eversource Energy, First Energy Corp., American Electric Power Company, Inc. and Public Service Enterprise Group, Inc. investor communications collected in TAPS Initial NOI Comments at 18-19.

[25] *See Xcel Energy Serv., Inc. v. Am. Transmission Co., LLC*, 140 FERC ¶ 61,058 (2012), *reh'g denied*, 147 FERC ¶ 61,089 (2014) (granting complaint challenging ATC's claim to construction and ownership rights associated with the 145-mile, 345 kV LaCrosse-Madison Line). The Commission addressed similar disputes in *Am. Transmission Co., LLC v. Midwest Indep. Sys. Operator, Inc.*, 142 FERC ¶ 61,090 (2013) and *ITC Midwest, LLC v. Am. Transmission Co., LLC*, 142 FERC ¶ 61,096 (2013), *reh'd denied*, 152 FERC ¶ 61,155 (2015). A developer granted a 150 basis point risk-based incentive for new transmission unsuccessfully sought to block joint ownership by the host TO—which did not seek that same rate incentive—to claim rights to build and own 100% of the facility. *Pioneer Transmission, LLC* 126 FERC ¶ 61,281 (2009); *Pioneer Transmission, LLC,* 130 FERC ¶ 61,044 (2010); *Pioneer Transmission, LLC v. N. Ind. Pub. Serv. Co.*, 140 FERC ¶ 61,057 (2012); *Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, PP 3-14 (2018). TAPS Initial NOI Comments (at 19-20) also highlight TO battles to retain federal rights of first refusal.

pencils, capping their annual transmission revenue requirement ("ATRR"), ROE, and capital structure to win projects, resulting in significant consumer benefits.[26] Their willingness to forgo even risk-reducing incentives to win selection speaks volumes to the value of the right to construct transmission with assured cost recovery.

In the face of overwhelming evidence of robust transmission investment under current policies, the NOPR points to various industry changes (in generation mix, load patterns, and transmission planning), but does not connect these developments to a need for the proposed incentives policy changes. For example, the NOPR states (P 26) "the types of transmission projects that are needed, and the use of rate treatments to incent them, must evolve to reflect the changes in market fundamentals." But its proposed Economic Incentives are targeted at projects that are already the focus of Order 1000,[27] and most likely to be built anyway. The NOPR's proposal to reward projects that provide reliability benefits above and beyond what is required for an adequate level of reliability calls into question whether such projects are prudent, much less worthy of ROE incentives due to unspecified "changes in market fundamentals."

The NOPR does not explain why changes in transmission planning (P 30) require fundamental changes to incentives policy. In fact, changes in transmission planning since the issuance of Order 679 have been accompanied by strengthened ability by planning

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[26] Brattle Group Order 1000 Discussion Paper at 1, 13, 15. For example, the winner (NextEra Energy Transmission Midwest, LLC) of the stiff competition for MISO's Hartburg-Sabine Junction 500 kV project came in *below* MISO's scoping bid and the median bid, with an ROE fixed at 9.8% with 45% equity, foregoing construction work in progress ("CWIP") and Allowance For Funds Used During Construction ("AFUDC"), and limiting ATRR and Operation and Maintenance ("O&M") costs over the first ten years. *Selection Report: Hartburg-Sabine Junction 500 kV Competitive Transmission Project,* MISO, 5-6, 21 (Nov. 27, 2018), https://cdn.misoenergy.org/Hartburg-Sabine%20Junction%20500%20kV%20Selection%20Report296754.pdf ("MISO Selection Report"). See TAPS Initial NOI Comments at 20-21.

[27] Order 1000 itself was justified by the nation's changing generation mix. Order 1000, P 45.

regions, especially RTOs, to get needed transmission built, either through RTO directives or competition. These changes *reduce* the need for ROE incentives and argue against incentives (such as those proposed) that threaten to disrupt those planning processes.[28] If the Commission believes existing transmission planning processes are not producing the right types of investment, those processes should be improved and better targeted. Incentives—particularly the blunt ROE incentives proposed—won't do the trick.

Indeed, the NOPR concedes that the Commission has *not* evaluated the effectiveness of the existing incentives regimen, stating (P 115): "Experience to date suggests that current information collection related to FPA section 219 incentives is insufficient to determine the effectiveness of the individual incentive grants, or to evaluate the Commission's overall incentives program."[29] Unable to make that essential assessment, the NOPR rests its major reforms on speculation. The NOPR states (P 31) that reform "*may* be necessary to *continue* to satisfy" (emphasis added) Section 219 obligations, and (P 32) that current policies[30] "*may* not fully accomplish" (emphasis added) Section 219's purposes. These conjectures not only run up against strong evidence to the contrary, but overlook that the Commission's existing incentives approach is already appropriately tailored to Section 219's directives, by including a baked-in demonstration of reliability and economic benefits, along with the required nexus that the

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[28] *See* Parts II.B, IV.E, V.A, VI.B.4. *See also* TAPS Initial NOI Comments at 36, 43-51.

[29] *See also id.* P 33 (implicitly conceding the Commission's inability to assess the effectiveness of incentives). While improved information collection through enhancement of Form FERC-730 may enhance the Commission's ability to do so, improving information collection does not require a change in the basis for awarding incentives or their magnitude.

[30] *See* TAPS Initial NOI Comments at 22-24.

incentive will achieve Section 219(b)(1)'s express purpose of "promoting" investment—a crucial link eliminated under the NOPR's proposal.

Nor is the missing support supplied by the NOPR's statement (P 33) that its new approach should increase certainty for developers and provide transparency as to how the Commission determines benefits. The existing system—in which full cost recovery plus a Commission-regulated ROE is the default—already provides extraordinary certainty. If anything, the NOPR's proposal would introduce *less* transparency as to why incentives are granted. The proposed fact- and assumption-specific benefits-based regimen necessarily introduces complexity, data and complicated modeling issues, and evidentiary hearing process requirements, none of which can be adequately addressed under the expedited procedures envisioned by the NOPR. And the new incentives processes could sidestep and supplant the much more deliberate open, transparent planning processes the Commission has found necessary for just and reasonable transmission rates.

Reversal of policies that have been demonstrably successful in achieving Section 219's purpose cannot lawfully rest on a showing that fails to meet the rationally-related standard.[31] It is also telling that NOPR's "need for reform" never even mentions one of its most costly (and unjustified) proposed changes—its proposed doubling of the RTO adder.[32] TAPS urges the Commission not to adopt the NOPR's proposed changes.

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[31] *FCC v. Fox Television Stations, Inc*., 556 U.S. 502, 515-16 (2009) ("An agency may not, for example, depart from a prior policy *sub silentio* or simply disregard rules that are still on the books."). *See also Encino Motorcars, LLC v. Navarro,* 136 S. Ct. 2117, 2125 (2016) ("Agencies are free to change their existing policies as long as they provide a reasoned explanation for the change.").

[32] *See* NOPR Part III.

II. THE PROPOSED SWITCH TO BENEFITS-BASED INCENTIVES VIOLATES SECTION 219 AND UNDERMINES ITS PURPOSES

A. The NOPR's Proposed Benefits-Based Project Incentives Are Inconsistent with Section 219's Requirements

The Commission's current risks and challenges approach to incentives is designed to advance Section 219(b)(1)'s objective of "promoting capital investment" in projects that, as required by Section 219(a), "benefit[] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." And it does so in a manner that adheres to the overarching limitation on incentives that rates approved under Section 219 "are subject to the requirements of sections [205] and [206] of this title that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential." Section 219(d). To accomplish these Congressional directives requires a demonstration of statutorily-required benefits.[33] Also indispensable to compliance with Section 219 is the nexus test and required showing that the total package of incentives (including non-ROE incentives that can reduce the project-specific return required by investors) is tailored to the risks and challenges of the particular project not already accounted for in the applicant's base ROE (taking account of the risk-

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[33] This showing can be satisfied through demonstration or the rebuttable presumption. *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 117 FERC ¶ 61,345, P 50 (2006) ("Order 679-A"), *clarified*, 119 FERC ¶ 61,062 (2007), established a limited rebuttable presumption that a project will qualify for incentive rate treatments if it results from a regional planning process or has been approved by a state commission or siting authority, and the applicable process considered whether the project ensures reliability or reduces congestion.

The consumer-benefits threshold requirement was buttressed by the 2012 Policy Statement's explicit expectation that a project for which ROE incentives are sought "provide demonstrable consumer benefits by making the transmission grid more efficient, reliable and cost-effective" (2012 Policy Statement P 22); its non-exclusive list of projects where ROE incentives may be warranted (*id.* P 21, i.e., the project relieves chronic or severe congestion that has demonstrated cost impacts; unlocks location constrained resources with limited or no access to the market; applies new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities); and its expectation that applicants show consideration of alternatives in a relevant planning process to help identify the project's benefits and its role in promoting a more efficient, reliable, and cost-effective grid (*id.* P 25) reducing incentives), as evaluated on a case-by-case basis.[34] The current cost-driven incentives regimen allows for additional equity returns for a particular project where the cost of capital required to attract investment is greater—i.e., where the project's risks and challenges exceed the normal risks reflected in the base ROE,[35] and cannot be adequately mitigated by non-ROE, risk-reducing incentives and measures.[36] This framework balances the interests of investors and consumers, restricting incentives to those needed to promote the investment.

The NOPR proposes to cast aside this approach and grant ROE incentives based on an expedited Commission evaluation of the incentive applicant's benefit claims (apparently without even considering project costs in the case of reliability benefits), and with respect to ROE adders, without requiring any showing that an ROE incentive in excess of the base ROE is needed to promote the investment.[37] Untethered to any showing that an incentive is needed to induce project-specific investment, the NOPR's approach amounts to a "bonus for good behavior" (or, as in the case of above-and-beyond reliability incentives, a bonus for gold-plating)—an approach FERC rightly rejected in Order 679 (P 26). It invites a form of value-of-service pricing that is contrary to the just and reasonable standard.[38] These bonuses are particularly inappropriate for projects that are likely to be built in any event (e.g., economic projects selected through Order 1000

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[34] Order 679, P 26, Order 679-A, P 27, and the 2012 Policy Statement, PP 10-26.

[35] Order 679, P 27.

[36] 2012 Policy Statement P1.

[37] *See* NOPR P 39.

[38] *See W. Sys. Power Pool*, 55 FERC ¶ 61,099, at 61,316 & n.64 (1991) ("[V]alue of service pricing . . . is the hallmark of a monopoly.") (citing James C. Bonbright, *Principles of Public Utility Rates* 88-89 (Columbia University Press 1966)), *stay granted*, 55 FERC ¶ 61,154, *reh'g granted*, 55 FERC ¶ 61,495 (1991), *petition for review denied sub nom. Envtl. Action v. FERC*, 996 F.2d 401 (D.C. Cir. 1993).

planning processes, including competitive development processes; projects that the RTO has the authority to require the transmission owner to construct).

This fundamental flaw is highlighted by the proposal to grant multiple benefits-based incentives for the same project, so long as no more than 250 basis points are added to the project's ROE. All transmission projects can potentially provide multiple types of benefits, as Order 679 recognized.[39] But instead of grappling with the fact that "economic" and "reliability" benefits are intertwined and in some cases identical, the NOPR seems to allow multiple incentives for the same basic engineering function of a project. The same increased transfer capability that can produce "economic benefits" might be claimed as a providing "above and beyond" reliability or "resilience" benefits qualifying for an additional incentive;[40] and the NOPR's overly-generous 250-basis-point cap would accommodate and encourage stacking incentive claims. The main effect of this approach will be to promote ingenuity in claiming different types of overlapping benefits. While the NOPR asks (P 55) whether "measurement" of economic benefits can be distinguished from other types of benefits "so that double-counting of benefits does not occur," the question erroneously presupposes that using different benefit metrics could make additive incentives just and reasonable, without considering whether any ROE incentives, much less all of them, are needed to promote construction of the project.

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[39] See Order 679 P 42 ("we expect there will be few transmission projects that provide one type of benefit but not the other); 344 ("In many instances new investments in transmission may both improve reliability and reduce congestion").

[40] *See*, *e.g.*, NOPR P 68 ("First, transmission projects that significantly increase import or export capability between balancing authorities can provide significant and demonstrable reliability benefits. For example, increasing import capability can provide access to additional generation capacity which could be necessary to prevent load shedding or restore load generation balance in an emergency. In addition, creating additional transmission capability on frequently constrained interfaces can reduce the likelihood of a System Operating Limit exceedance that can damage equipment and disrupt system operations.").

Notwithstanding the NOPR's pivot to benefits-based incentives, it proposes to retain (with limited expansion) risk-reducing non-ROE incentives for projects meeting the existing rebuttable presumption,[41] while eliminating the obligation to show nexus and that the total package of incentives is tailored to the project's risks and challenges not accounted for in base return ROE. The NOPR does so because these incentives "remove regulatory barriers and other impediments to investment" (P 38)—i.e., they reduce project risks[42]—but without accounting for the impact of their award on the ROE required by investors, despite precedent recognizing that these incentives reduce required ROE.[43] The Commission cannot rationally find its ROE incentives just and reasonable without considering the ROE impact of risk-reducing non-ROE incentives.

Section 219 cannot be satisfied by granting additive, "check-the-box" ROE incentives (plus non-ROE incentives) based solely on evaluation of claimed benefits. For incentives to satisfy Section 219, the question is not just whether the project "benefit[s] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion" (Section 219(a)), but also whether the incentive "promotes" such investment (Section 219(b)(1)) and is just and reasonable (Section 219(d)), which

[41] Contrary to the NOPR (P 82), the proposed regulations do not clearly limit application of the rebuttable presumption to eligibility for non-ROE incentives. *See* Proposed regulations Section 35.35(j) at NOPR P 154. If the Commission proceeds to adopt a final rule along the lines of the NOPR, the regulations need to expressly limit the application of the rebuttable presumption, so that the language cannot be read as allowing the rebuttable presumption to be used to qualify a project for benefits-based ROE incentives.

[42] *See* Order 679-A P 27; 2012 Policy Statement PP 11-16.

[43] *See S. Cal. Edison Co.*, 112 FERC ¶ 61,014, P 61 & n.49 (2005). Nor does the NOPR recognize that these incentives shift risk and costs to consumers. For example, the grant of the abandoned plant recovery incentive, will increase ratepayer costs in the event of project abandonment beyond the developer's control.

depends on whether the incentive is needed to secure those benefits—i.e., it materially affects voluntary, prospective behavior.[44]

To be lawful, an incentive's increased costs to consumers must be offset by benefits that would not be realized absent the inducement provided by the incentive.[45] And the incentive must be no greater than is needed to induce the desired action. As the D.C. Circuit explained in *City of Detroit v. FPC*, 230 F.2d 810, 817 (D.C. Cir. 1955), "[i]f the Commission contemplates increasing rates for the purpose of encouraging exploration and development . . . it must see to it that the increase is in fact needed and is no more than is needed, for the purpose." *See also Farmers Union Cent. Exch. v. FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984) (rejecting incentive rates because the Commission '"must see to it that the increase is in fact needed, and is no more than is needed, for the purpose."' (quoting *City of Detroit*, 230 F.2d at 817)).

Because the roots of the nexus test are in the FPA's just and reasonable standard—which Section 219(d) expressly requires all incentives to satisfy—the

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[44] *See City of Charlottesville v. FERC*, 661 F.2d 945, 953-54 (D.C. Cir. 1981) (rejecting award of an incentive treatment where the factual record did not demonstrate that level of investment had changed as a result of the incentive policy); *Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966, 974 (9th Cir. 2018) ("*CPUC 2018*") ("FERC has a long-standing policy that incentives should only be awarded to induce future behavior . . . . [T]here must be a connection between the incentive and the conduct meant to be induced . . . . The policy prohibits FERC from rewarding utilities for past conduct or for conduct which they are otherwise obligated to undertake."); *New England Power Pool*, 97 FERC ¶ 61,093, at 61,477 (2001) (incentive denied to avoid "unjustly reward[ing] NEP for doing what it is supposed to do, i.e., to adequately maintain its facilities in a prudent, cost-effective manner."), *order on reh'g*, 98 FERC ¶ 61,249 (2002). *See also Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities*, 61 FERC ¶ 61,168, at 61,594 (1992) ("1992 Policy Statement"), *reh'g denied*, 63 FERC ¶ 61,110 (1993).

[45] *See, e.g., Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) ("The Commission knew. . .that unless it approved the PG&E incentives, the project would likely not be built in the near future . . . . Although it was well-known that Path 15 was constrained and although this suggested a ready market if new transmission lines were built, no party stepped forward to construct upgrades. Only after WAPA issued its request for proposals did it find participants for the project, and then only if incentives were offered . . . . [T]he incentives amounted to a small portion of total energy costs and are greatly outweighed by the benefits the customers will receive.").

Commission cannot dispense with it on the basis that "FPA section 219 neither includes this standard nor requires the Commission to find that the transmission project would otherwise not occur without the incentive."[46] Nor does the fact that Order 679's nexus test did not impose a rigid "but for" prerequisite grant a license to burden consumers with hefty ROE incentives that serve no purpose whatsoever.[47] Order 679-A clarified that a loose connection would not be sufficient; applicants must demonstrate that "the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project." *See* Order 679-A, P 27 (emphasis omitted) and 18 C.F.R. § 35.35(d). This test is intended to ensure "incentives are not provided in circumstances where they do not materially affect investment decisions." Order 679-A, P 25.[48]

By stripping out any required demonstration that would prevent awarding incentives "in circumstances where they do not materially affect investment decisions" (Order 679-A, P 25), the NOPR's proposal is inconsistent with Section 219's focus on awarding incentives shown necessary to *promote* transmission development and Section

[46] NOPR P 35.

[47] *See* Glick Dissent P 4 (footnote omitted) ("incentives must actually incentivize something. A payment that does not incentivize anything is a handout, not an incentive. Handing out customers' money to transmission owners without a strong belief that that money will induce beneficial conduct is unjust and unreasonable and inconsistent with Congress' intent behind section 219.") While given the required demonstration of benefits, as buttressed by the planning process, we question Commissioner Glick's concern that the risks and challenges approach is insufficiently focused on beneficial projects, we agree that it is "categorically unjust and unreasonable …[to] hand out customers' money for nothing in return." *Id.* P 5.

[48] The NOPR's citations (P 35 n.39) to Order 679's rejection of a "but for" (Order 679 PP 48 and 53) do not support elimination of the nexus test, as illustrated the sentence following the quoted sentence in Order 679 P 48, which affirms adoption of the nexus test. Similarly, the NOPR's quotation (P 35 n.39) from *Connecticut Department of Public Utilities Control v. FERC*, 593 F.3d 30, 34 (D.C. Cir. 2010) ("nothing in the law or FERC's stated purpose required FERC to adduce evidence … 'that the adder would produce new transmission investment'") was in the context of applying a nexus test to a evaluate a time-limited incentive ("we review the record to determine whether FERC had a reasonable basis for concluding that the incentive might benefit consumers by *accelerating* completion of the projects"). *Id.* (emphasis in original).

219(d)'s overarching requirement that incentives must be just and reasonable. The NOPR's approach would burden consumers and our economy with significant incentive costs, far exceeding those available under the current approach, that are not even rationally related to the statute's goal of promoting investment. And it does so at a time when there is strong evidence that the extra incentives are unnecessary, as shown in Part I.

In short, granting TOs monopoly rents in the form of additive ROE incentives for the benefits of transmission investments for which they are already entitled to earn a base ROE, claim an exclusive right to build, may be obligated to build (e.g., by tariff or RTO agreement), or (as in the case of "reliability" benefits) may well be gold-plating, without any showing that a greater ROE is needed to attract that investment, cannot be squared with Section 219. The unnecessary extra costs will not only harm consumers and our economy, but may increase resistance to securing state approvals of needed transmission, making it harder to get needed transmission sited and constructed in the long run.

B. The NOPR's Benefits-Based Approach Undermines Transmission Planning and Competitive Development Policies the Commission Found Necessary for Just and Reasonable Rates

The NOPR's benefits-based incentives, if adopted, would undermine the Order 890 and Order 1000 planning processes, including associated competitive transmission development processes, that the Commission has put in place to ensure just and reasonable rates given the need for transmission expansion to support reliable service and our changing generation mix. It recognized the opportunity for undue discrimination in the absence of Order 890's open, transparent, and collaborative planning process,[49] as well as the continued opportunities for discrimination and potential for unjust and unreasonable rates in the absence of the Order 1000's regional planning process.[50] It found that given significant transmission investments being made, regional planning and interregional coordination are needed to ensure the most cost-effective and efficient projects get built,[51] i.e., "the *right* transmission facilities."[52]

For even longer, the Commission has encouraged formation of RTOs that have ultimate responsibility for planning and expansion "to ensure a least cost outcome that maintains or improves existing reliability levels" and least-cost solutions to congestion that imposes significant costs warranting mitigation, while coordinating with state authorities having responsibility over siting.[53] The Commission viewed "independent governance of the RTO [as] a necessary condition for nondiscriminatory and efficient planning and expansion,"[54] and recognized the efficiencies and benefits of a single entity performing this function with a regional view.[55]

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[49] Order 890, PP 422-25. E.g., upgrades to unlock constrained generation could be designed to relieve constraints on the TO's existing or planned generation, without fully taking into account the TDU needs.

[50] Order 1000, PP 42-50, 58-59.

[51] *Id.* PP 42-50. Order 679-A and the 2012 Policy Statement also rightly recognize the value of the regional process in evaluating alternatives (through the rebuttable presumption and the expectation of a demonstration of consideration of alternatives).

[52] *Id.* P 50 (emphasis added).

[53] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, FERC Stats. & Regs. at 31,164 (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). *See also* 18 C.F.R. § 35.34(k)(7).

[54] Order 2000, FERC Stats. & Regs. at 31,165.

[55] *Id* , FERC Stats. & Regs. at 31,082-83, 31,165.

The NOPR's proposal to award incentives based on Commission evaluations of expected benefits from individual projects would be a giant step backward. Because such a process would short-change crucial factors that are best developed through a robust planning process, above-cost incentives may be awarded to projects that are more costly, less cost efficient or effective, and designed to favor the TO's own load or generation.

And it will undermine existing planning processes that use benefit estimates to evaluate and select projects. The Commission has previously found that the evaluation of proposed projects requires resolution of complex factual and modeling issues, including assessment under a range of stakeholder-vetted scenarios of benefits, costs, and alternative transmission and non-transmission solutions.[56] At the Grid Enhancing Technologies ("GETs") Workshop, Craig Glazer of PJM warned that linking rate incentives to the project-specific benefit-cost analyses used in transmission planning would make those studies more contentious; and he posited that the risk of litigation created by a such an approach would lead to parties "sitting here two or three years from now regretting what we did."[57]

RTO panelists at the Workshop also strongly opposed the creation of a separate process, outside existing regional planning processes, for estimating the future benefits from new projects. New York Independent System Operator ("NYISO") panelist Lin, for example, warned that creating such a separate process could disrupt NYISO's existing

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[56] *See* Order 679 P 58. *See also* Order 1000 PP 149-50.

[57] Grid-Enhancing Technologies Workshop Transcript Day 2, 288:18–289:3 (Glazer, PJM), *Grid Enhancing Technologies*, Docket No. AD19-19-000 (Jan. 6, 2020), eLibrary No. 20200106-4005 ("GETs Tr. Day 2") ("If we now link the incentive to the individual cost benefit analysis we're doing, I guarantee you every one of those will be litigated . . . . If we're going to litigate the cost benefit on each one of those because now there's all these ratemaking incentives, we're going to be sitting here two-three years from now regretting what we did.").

Order 1000 planning process that is finally working.[58] Similarly, CAISO panelist Millar testified that:[59]

> we are concerned about having a second process overlaid on top of the one we already have in creating duplication and perhaps conflict, with people promoting one set of solutions on one side, a different competing set of solutions through the other process, and having to sort out through some litigation which process is supposed to prevail.

TAPS also explained how benefits-based incentives threaten to undermine planning processes by encouraging bypass that hollows out the range of alternatives presented to planners, and by providing large financial subsidies for the construction of expensive projects that have not been identified as the most cost-effective and efficient.[60]

Notwithstanding these warnings, the NOPR proposes a separate benefit-determination process for applicants seeking incentives. While it proposes to confer a rebuttable presumption to RTO adjusted production cost calculations (NOPR P 50), it would still allow individual applicants to develop their own economic-benefit calculations and present them to the Commission. And it would invite applicants to seek reliability, economic, and technology incentives for projects not selected or evaluated through an Order 890 or 1000 planning process. While acknowledging RTO concerns that a benefits-based incentives approach could duplicate or interfere with RTO transmission planning efforts (NOPR P 44), the NOPR fails to recognize the damage its proposal will inflict on planning processes, or to mitigate these adverse impacts on long-standing Commission policies designed to produce just and reasonable rates.

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[58] GETs Tr. Day 2, 334:2-19.

[59] *Id.* 333:20-25 (Millar, CAISO). *See also id.* 286 (Glazer, PJM), 296:9-22 (Millar, CAISO).

[60] *See* TAPS Initial NOI Comments at 44-45.

C. The NOPR's Proposal to Reward Claimed Benefits Removed from Commission-Approved Planning Processes Is Contrary to Section 217

Section 217(b)(4) requires the Commission to exercise its authority under the FPA to facilitate the planning and expansion of the grid to meet the reasonable needs of LSEs, including TDUs, "creat[ing] a requirement for the Commission"[61] that it is not free to ignore. The Commission has found adoption of the Order 890 and Order 1000 planning processes to be consistent with its duties under this provision.[62] As discussed in Part II.B, to the extent the NOPR would award above-cost incentives to projects not selected through those planning processes, it conflicts with Section 217(b)(4).

A benefits-based approach runs contrary to Section 217(b)(4) by incenting Transmission Providers ("TPs") to delay needed upgrades. TPs have long been required to plan and expand the grid, consistent with good utility practice, to comparably meet the needs of network customers,[63] a requirement buttressed by tariff requirements intended to give the TP skin in the game.[64] Benefits-based incentives based on piecemeal project evaluation could financially reward the opposite, incenting TPs to delay "business as usual" investments, and then claim that its overdue project provides a range of benefits warranting above-and-beyond incentives.[65] While this may be less of an issue where

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[61] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 (D.C. Cir. 2014).

[62] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, P 169 & n 31 ("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) (citing Order 890-A P 172).

[63] *Pro Forma Open Access Transmission Tariff*, FERC, § 28.2 (July 18, 2013), https://www.ferc.gov/sites/default/files/2020-05/pro-forma-OATT.pdf ("*Pro Forma* OATT").

[64] *See, e.g.*, *Pro Forma* OATT §§ 33.2, 33.3 (requiring least cost re-dispatch of TP and network customer resources, with costs shared on a load ratio basis).

[65] *See* Part VI.A.4.

RTOs independently assess system needs and can direct upgrades, the Commission should not violate Section 217(b)(4)'s directive by rewarding TPs that have failed to plan and expand their system to meet the reasonable needs of LSEs on a timely basis.

D. The NOPR's Approach to Incentives May Impede Siting, Conflicting with Section 219's Goals

An incentives system based on Commission evaluation of benefits, disconnected from planning, is likely to impede the ability to get new transmission sited, contrary to the purposes of Section 219. The NOPR's approach puts the Commission in the position of picking winners and losers among projects that may well have been competing alternatives in a regional planning process, as well as projects that did not participate in that process. Or worse, the Commission could make them all "winners" (with hefty incentive ROE price tags) that proceed through state siting processes, even though constructing them all makes no sense from a planning perspective—fueling anti-siting sentiments, overwhelming and alienating state siting authorities, and making it less likely that the most effective and efficient project will be built.

The benefits identified as the basis for above-cost incentives—and the incentives themselves—may align poorly with state siting agency requirements or attitudes, providing fodder to project opponents[66] and complicating siting. For example, a project that was granted incentives for providing reliability benefits far beyond those required to achieve the adequate level of reliability required by NERC standards may not be well received by state siting boards that might understandably question the need for such a

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[66] ROE incentives may also incite grass roots opposition. *See, e.g.*, *Understanding the Consequences and Responses to Wisconsin Utilities' Excessive Spending*, Soul of Wisconsin (June 2015), http://soulwisconsin.org/Documents/Understanding%20Consequences%20of%20Utility%20Debt_V04.pdf.

project. Multiple ROE adders totaling up to 250 basis points could fire up local opposition. By creating an environment in which siting—the most significant risk that transmission developers must face—is harder and more contentious, the NOPR makes it less likely that projects providing consumer benefits get built, undermining Section 219.

III. TO ACHIEVE SECTION 219'S PURPOSES, THE COMMISSION NEEDS TO RETAIN IF NOT EXPAND ITS INDUCEMENT TO INCLUSIVE JOINT OWNERSHIP WITH PUBLIC POWER

A glaring omission in the NOPR is any effort to promote or leverage joint ownership with public power and other TDUs, which the Commission has repeatedly encouraged, highlighting the value of "increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the grid by transmission customers."[67] The Commission has recognized that TDU participation is consistent with Section 219's goals of "encouraging a deep pool of participants,"[68] and benefits consumers as well as TDUs that can use revenues from transmission ownership to offset increasing transmission rates.[69] Going beyond mere encouragement, the 2012 Policy Statement, in expressing the Commission's expectation that an ROE incentives

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[67] Order 1000, P 776 (citing Order 890 P 593). *See also* Order 1000-A, P 81.

[68] Order 679, PP 354, 357. *See also* Order 679-A, P 102.

[69] For example, in granting municipal joint owners the ability to utilize hypothetical capital structures, the Commission stated: "[A]llowing Central Minnesota to receive a revenue requirement . . . that reflects the higher capital costs of the investor-owned utilities' will offset the Midwest ISO transmission rates that its members pay, which largely reflect those investor-owned utilities' higher capital costs, thereby allowing Central Minnesota and its members to effectively reduce their future transmission rates to reflect their lower capital costs to mitigate their investment risks associated with the project." *Cent. Minn. Mun. Power Agency*, 134 FERC ¶ 61,115, P 31 (2011). It also "noted that encouraging public power participation in such projects is consistent with the goals of section 219 of the FPA by encouraging a deep pool of participants." *Id.* P 19 n.23.

applicant demonstrate it is minimizing its risks during project development, identified joint ownership arrangements as a risk-reducing measure to be considered:[70]

> [A]pplicants may take measures to mitigate risks associated with siting and environmental impacts by pursuing joint ownership arrangements. The Commission encourages incentives applicants to participate in joint ownership arrangements and agrees with commenters to the NOI that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks.[33]
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> [33] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 354, 357; Order No. 679-A FERC Stats. & Regs. ¶ 31,236, at P 102. *See also Central Maine Power Company*, 125 FERC ¶ 61,182, at P 61 (2008); *Xcel Energy*, 121 FERC ¶ 61,284 at P 55 (2007). Evidence regarding whether an applicant for incentives considered joint ownership arrangements may be relevant in assessing whether the applicant took appropriate steps to minimize its risks during project development.

In moving from a risks and challenges approach to benefits-based incentives, however, the NOPR never mentions joint ownership. While proposing to maintain (with some expansion) risk-reducing non-ROE *incentives* because they "remain vital in facilitating the investment in and the development of transmission projects as they remove regulatory barriers and other impediments to investment" (NOPR P 38), the NOPR does not mention risk-reducing *measures* including joint ownership.

TAPS urges the Commission to fulfill its statutory responsibility by correcting that omission and at least maintaining, if not enhancing, the inducement to joint ownership. As discussed, joint ownership advances Section 219(b)(1)'s goal of promoting capital investment in the grid "regardless of the ownership of the facilities," opening up the TO club. Section 219's purposes are thwarted if a needed project does not get built because it faces greater financial or siting risk without joint ownership. And Section 217(b)(4) directs the Commission to exercise its "authority . . . under [the Act] in

[70] 2012 Policy Statement P 24 & n.33.

a manner that facilitates the planning and expansion of the transmission facilities to meet the reasonable needs of load-serving entities," imposing a "requirement for the Commission"[71] that is significantly furthered by joint ownership arrangements. Thus, Section 219(b)(1), coupled with Section 217(b)(4), call for targeted inducements for inclusive joint ownership arrangements whether or not the Commission departs from the risks and challenges approach.

As TAPS previously described,[72] inclusive joint ownership arrangements, whether structured as an inclusive Transco,[73] a shared system,[74] or joint ownership of new transmission facilities,[75] result in collaborative and inclusive planning, development, and siting of transmission, and have proven highly effective in getting transmission built to meet the needs of all LSEs. Benefits include:

1. *Inclusive joint ownership makes joint planning real.* Although the Commission has issued rules to promote open and transparent planning, there is a big practical

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[71] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 (D.C. Cir. 2014).

[72] *See* TAPS Initial NOI Comments at 6-14; TAPS*, Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Getting Needed Transmission Sited and Built*, TAPS Policy Papers (Sept. 7, 2012), https://tapsgroup.org/wp-content/uploads/2013/01/TAPS-Joint-Ownership-White-Paper.pdf ("TAPS White Paper"). For more details, *see* TAPS*, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost*, TAPS Policy Papers (June 2004), https://tapsgroup.org/wp-content/uploads/2013/01/effectivesolutions.pdf, filed with the Commission in *Promoting Transmission Investment Through Pricing Reform*, Docket No. RM06-4-000 (TAPS Comments, Attach 1 (Jan. 11, 2006), eLibrary No. 20060111-5132).

[73] E.g., Vermont Electric Power Company ("VELCO"), formed in 1956, which features municipal and cooperative participation, is an early example. *See* TAPS White Paper at 2. The ownership structure contributes to VELCO's ability to influence legislation and secure regulatory and siting approvals. It also is an important vehicle for collaboration among all Vermont utilities for purposes of VELCO's project planning, operations, and cost allocation decisions. *See History*, VELCO (last accessed June 23, 2020), https://www.velco.com/about/history.

[74] In shared system arrangements (include those long in place in Georgia, Indiana, Minnesota, North Dakota and South Dakota), transmission facilities of two or more utilities are planned and operated jointly, as a single system, pursuant to a long-term agreement. Ownership in the joint system generally is in proportion to each participant's load ratio share of the customer load connected to the system, although there are a variety of ways this ownership share can be achieved, e.g., through owning an undivided share of the entire joint system; owning discrete facilities; owning new facilities. *See* TAPS White Paper at 2-3.

[75] E.g., CapX2020, discussed below and in the TAPS White Paper at 3.

difference when all LSEs are at the table as owners, aligning the ownership structure with the reality of the way the network operates and should be planned. When diverse parties are owners, greater openness and transparency, and more balanced decisionmaking flow automatically.

2. *Inclusive joint ownership results in a better and more efficient transmission system planned to meet multiple needs*. This has been the experience of TAPS members in Wisconsin, where combining multiple systems into one jointly owned Transco (American Transmission Company, LLC ("ATC")) has led to a more rationally developed system than balkanized planning and construction. We also see it in CapX2020, which currently consists of ten investor-owned, municipal, and rural cooperative utilities in Minnesota, North Dakota, South Dakota, and Wisconsin that jointly plan needed transmission upgrades and have opportunities to jointly own those facilities.[76] This approach is far better than reactively planning for discrete transmission or interconnection service requests after the requests are made.

3. *The diverse support that joint ownership provides is very important in siting*. By meeting the needs of multiple utilities, a joint project is able to demonstrate multiple benefits. Although municipal and cooperative participation may be relatively small percentage-wise, these utilities bring a wealth of political support to state approval processes, which can make all the difference in speeding up permitting and addressing local concerns.

4. *Inclusive joint ownership arrangements provide the critical alignment of interests that makes it easier for state regulators to approve proposed transmission projects*. When state commissions are presented with projects that are least-cost because they meet multiple needs, when they see unity among the utilities on need, and when they are faced with a broad base of support from diverse stakeholders, it is far easier for them to grant requested authorizations.

5. *Inclusive joint ownership makes cost allocation easier to resolve, although it still remains a thorny issue*. TDUs face adverse competitive impacts from the obligation to pay the increasing costs of transmission, while transmission-owning LSEs have an earnings opportunity, rather than simply an obligation to pay. Joint ownership arrangements can provide TDUs a comparable opportunity to hedge those cost increases. For instance, although transmission rates paid by ATC customers have materially increased because of ATC's major construction program, municipal and cooperative owners have been able to partially offset that increase. This ability has made it much easier for them to support ATC's build-out.

6. *Inclusive joint ownership spreads the risk of major projects broadly and provides a variety of sources of capital for projects*. The financial diversity and strength

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[76] *CapX2020*, CapX2020 (last accessed June 23, 2020), http://www.capx2020.com/ ("CapX2020 Webpage").

achieved through joint ownership arrangements should be increasingly valuable. Rating agencies have recognized that ATC's inclusiveness is a significant benefit.

7. *The broad base of support achieved through joint ownership arrangements can be essential to securing state legislative action required to better align retail rate recovery with the need for supporting major transmission investment*, as has occurred in Minnesota with the full support of the CapX2020 group.

8. *Inclusive joint ownership arrangements reduce the need for the Commission to referee rate and other disputes*.

9. *Inclusive joint ownership arrangements can reduce transmission rates.* Where public power ownership is direct, transmission ratepayers receive several rate-reducing benefits. Public power utilities are not subject to income taxes, and they flow their tax savings through to ratepayers. Their lower debt cost further reduces rates. Even when set on a hypothetical basis, public power utilities' capital structures commonly include less equity than investor-owned utilities' actual capital structures. While not all these rate-reducing attributes apply to inclusive Transcos, some may depending on the particular corporate structure. For example, the lack of tax allowance for public power owners reduces ATC's rates.

10. *Inclusive joint ownership arrangements benefit consumers.* The benefits listed above work together to produce transmission better designed to meet all needs, and that can be sited and built more quickly. As a result, inclusive joint ownership arrangements benefit consumers and reduce costs.

Joint ownership arrangements have a long history of success,[77] and results of recent joint ownership arrangements are impressive. For example, ATC grew from $550 million in assets in 2001 to $5 billion, building more than 710 miles of new transmission, and connecting more than 6,220 MW of new generation.[78] CapX2020 has completed nearly $2 billion of investment in 800 miles of transmission including four 345 kV lines, making it the largest development of new transmission in the upper Midwest in 40 years.[79] As then-President of Otter Tail Power Company described in 2017:[80]

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[77] *See* TAPS White Paper at 2.

[78] *What We Do*, ATC (last accessed June 23, 2020), https://www.atcllc.com/about-us/what-we-do/.

[79] *CapX2050 Transmission Vision Report*, CapX2020, 8 (Mar. 2020), http://www.capx2020.com/documents/CapX2050_TransmissionVisionReport_FINAL.pdf.

> CapX2020 is a great example of collaboration. Investor-owned electric utilities, electric cooperatives, and municipally-owned electric utilities all worked together in an unprecedented way through transmission expansion to ensure we can continue to provide safe, reliable, and affordable energy to our customers. In this respect, we're a model for the rest of the country in transmission development. We've accomplished much more together than we ever could do alone.

Despite these significant benefits, investor-owned utilities continue to be reluctant to share transmission ownership with TDUs, preferring to keep transmission investments at Commission-approved ROEs to themselves.[81] Several TAPS members have sought to achieve joint ownership by partnering with GridLiance GP, LLC ("GridLiance") to propose non-incumbent projects through the Order 1000 competitive process, or in investments to improve service reliability for TDU communities; only one has moved forward.[82] Even where a TAPS member secured state commission approval of an investor-owned utility's stipulation and agreement that it "agrees to co-ownership,"[83] the

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[80] *CapX2020 Transforms Upper Midwest Electric Grid* (2017), http://www.capx2020.com/bss/Completion%20of%20Final%20CapX2020%20project.pdf.

[81] *See* TAPS White Paper at 5 n.6 (discussing several instances where TDU offers to invest have been rebuffed).

[82] Under the co-development agreement between TAPS member Kansas Power Pool, the City of Winfield is partnering with GridLiance to meet the City's Southwest Power Pool, Inc. ("SPP") reliability upgrade obligations and provide the City an opportunity to invest in those upgrades. *See GridLiance and City of Winfield Announce Transmission Partnership*, GridLiance (Jan. 29, 2019), http://www.gridliance.com/2019/01/29/gridliance-and-city-of-winfield-announce-transmission-partnership/.

[83] *See In the Matter of the Application of Sw. Power Pool, Inc. for a Certificate of Convenience and Auth. For the Limited Purpose of Managing and Coordinating the Use of Certain Transmission Facilities Located Within the State of Kan.,* No. 06-SPPE-202-COC, Order Adopting Stipulation and Agreement and Granting Applications PP 62-63 & Ordering Paragraph D (State Corp. Comm'n of Kan. Sept. 19, 2006), http://estar.kcc.ks.gov/estar/ViewFile.aspx/20060919090818.pdf?Id=c7e09bc4-6d81-46d1-98ff-d501bc6c3ec5 (approving TDU participation in ownership of transmission facilities). *See also In the Matter of the Application of Sw. Power Pool, Inc. for a Certificate of Convenience and Auth. For the Limited Purpose of Managing and Coordinating the Use of Certain Transmission Facilities Located Within the State of Kan.,* No. 06-SPPE-202-COC, Stipulation and Agreement § 15 (State Corp. Comm'n of Kan. July 14, 2006), http://estar.kcc.ks.gov/estar/ViewFile.aspx/20060714163903.pdf?Id=a06a90d9-0957-4763-ae7b-4b9377b09eeb ("Westar agrees with co-ownership with Kansas Municipals and/or Kansas municipal

Memorandum of Understanding to implement that commitment (contemplated to have been completed within fifteen days in 2006) has never been executed, despite years of negotiations.

In its Incentives NOI comments, GridLiance, supported by an affidavit from James Pardikes, MCR Performance Solutions, likewise demonstrated the role of public power participation in transmission ownership in creating a more reliable transmission grid and more competitive wholesale markets. It showed the significant barriers to such participation[84] and documented the resulting public power under-investments,[85] despite the interest of many in increasing their investment.[86] The GridLiance Comments and the Pardikes Affidavit show that the transmission planning disadvantage faced by public power entities significantly impacts reliability, resulting in service not comparable to what public utility TOs provide their own end-users and at higher cost. "Grid reliability and resilience should not depend on who provides the wholesale and retail service to an end-user if their circumstances are otherwise similar."[87]

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energy agencies in projects within the service territories of Westar Energy, Inc. and Kansas Gas and Electric Company to allow the cities and/or the municipal energy agencies to meet requests for Network Integration Transmission Service (NITS) . . . and that the cities and/or municipal energy agencies can invest in new transmission projects and /or upgrades within the service territories of Westar Energy, Inc. and Kansas Gas and Electric Company for such purposes" and further describing the Memorandum of Understanding to be entered to implement the joint ownership rights).

[84] Initial Comments of GridLiance 11-17, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 26, 2019), eLibrary No. 20190626-5308 ("GridLiance Comments"), *Id.*, Attach. A at 41-42 ("Pardikes Affidavit").

[85] Pardikes Affidavit at 5-23.

[86] *Id.* at 26.

[87] GridLiance Comments at 9-10; Pardikes Affidavit at 24-26. *See also* Pardikes Affidavit at 29-35 (describing other barriers to public power transmission ownership).

While the 2012 Policy Statement has been helpful in some cases,[88] continued and amplified inducements to joint ownership are required in order for the Commission to fulfill its responsibilities under Sections 217(b)(4) and Section 219. The need for such inducements is heightened by the NOPR's proposal to grant generous ROE incentives for projects lacking this crucial feature, thereby discouraging TOs from sharing ownership with TDUs, potentially undermining existing joint ownership arrangements, reducing their hedge value, and competitively disadvantaging TDUs.

Thus, even if the Commission generally departs from the risks and challenges approach, it is irrational not to maintain ROE incentive applicants' obligation to explain what measures they have taken to make it more likely that the project will be built. Consistent with the 2012 Policy Statement (P 24 & n.33), joint ownership should be recognized as such a measure. And failing to take such reasonable measures should have consequences for incentive applicants: those that have not provided a meaningful opportunity for joint ownership on a load-ratio-share basis to TDUs in the footprint that

[88] For example, MJMEUC, in a recent joint ownership agreement with Ameren, is planning the construction of facilities in Northeast Missouri that will strengthen the MISO transmission system and also provide additional reliability to Hannibal, Missouri. This is a project in which both MJMEUC and Ameren customers realize benefits, and illustrates the benefits that joint ownership can bring to all involved parties. TDU investment in previously planned CapX projects has also continued post-2012. WPPI Energy ("WPPI") has an approximately $15.3 million investment in the CapX Hampton-Rochester-La Crosse 354 kV line, energized in 2015. WPPI also has an approximately $7.1 million investment in the Badger Coulee 345 kV line, energized in 2018, which connects the Hampton-Rochester-La Crosse line to the Madison, Wisconsin area. Cedar Falls Utilities, a participant in TAPS member Midwest Municipal Transmission Group and a joint owner with MidAmerican Energy Company ("MEC") in the Webster, IA, substation, was invited to participate in a Midcontinent Independent System Operator, Inc. ("MISO") 2011 Multi-Value Project. Working with MEC, Cedar Falls transferred that interest to another MISO Multi-Value Project, in which it was able to invest $4 million in a jointly owned line energized in 2015.

Others have been less fortunate. For example, neither TAPS member Midwest Municipal Transmission Group nor its member Central Minnesota Municipal Power Agency ("CMMPA") has been able to secure an opportunity to invest in transmission development since financing on CMMPA's initial investment in CapX2020 closed in 2012, despite pursing further investment opportunities through CapX2020, as well as with GridLiance, ITC Holdings Corp. ("ITC"), and Transource Energy ("Transource").

will bear the cost of the facility (i.e., "inclusive joint ownership") should face a rebuttable presumption that they have *not* taken all appropriate steps to minimize their risks. This presumption should be particularly difficult to surmount if an applicant turns down TDU offers to participate. Because granting an ROE incentive to an applicant that failed to take prudent actions to increase the likelihood its project would get built does not accord with Section 219,[89] incentive requests from such applicants should face heightened scrutiny, if not outright rejection.

If maintenance or strengthening of the 2012 Policy Statement's encouragement of joint ownership is not included in any final rule, the Commission should find some other way to effectively induce such arrangements in the revised incentive structure. For example, the Commission should:

1. Consider offers of joint ownership as a prerequisite for obtaining the Abandoned Plant Incentive, or at least bar recovery of abandoned plant costs if a project is cancelled due to siting problems, unless the recipient had mitigated siting challenges by providing a meaningful opportunity for inclusive joint ownership. Absent such mitigation efforts, such abandonment would not be "for reasons outside [the applicant's] control." NOPR P 84.[90]

2. Consider joint ownership when calculating *ex post* benefit-cost ratios for the economic-benefit incentive. Specifically, the NOPR (P 60) asks whether for purposes of that calculation, the Commission should exclude costs resulting from factors beyond a developer's control. At most, the Commission should allow exclusion of cost overruns associated with siting only if, before obtaining initial approval of the project, the applicant extended offers providing a meaningful opportunity for inclusive joint ownership.[91]

3. Consider meaningful offers of inclusive joint ownership as a positive attribute that can minimize and overcome objections to benefits-based incentives. These include, but are not limited to:

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[89] Inclusion of TDU participants in the project would provide evidence of the meaningfulness of the offered opportunity.

[90] *See* Part VIII.

[91] *See* Part V.D.

a. Providing a basis for an exception to TAPS' proposed requirement that an incumbent TO waive all applicable ROFRs when seeking an ROE incentive;[92]

b. Providing evidence that an economic or reliability project does not discriminate in favor of the TO seeking the incentive (which incentive also may not be paid by the TO's bundled retail load);[93] and

c. Providing evidence that an above-and-beyond reliability project is not gold-plating, but provides benefits to the system as a whole.[94]

IV. THE FINAL RULE SHOULD INCLUDE OTHER ELEMENTS NECESSARY TO SATISFY SECTION 219

In addition to fundamental flaws in the NOPR's approach discussed in Parts II and III, the NOPR fails to include other elements that would be necessary, although not sufficient (without addressing the foundational flaws), for a final rule providing for benefits-based incentives to be consistent with Section 219 and otherwise lawful.

A. The Final Rule Must Adhere to the Voluntariness Requirement

Voluntariness has long been recognized as an essential requirement for incentive rates to be just and reasonable under the FPA;[95] and it is especially important in the context of benefits-based incentives that are not tailored to overcome the specific risks and challenges that create a barrier to investment in a particular project.[96] If adopted at

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[92] *See* Part IV.E below

[93] *See* Parts V.H and VI.B.5 below.

[94] *See* Part VI.B.5 below.

[95] See *City of Charlottesville v. FERC*, 661 F.2d at 953-54 (rejecting award of an incentive treatment where the factual record did not demonstrate that level of investment had changed as a result of the incentive policy); *CPUC 2018* at 974 ("An incentive cannot 'induce' behavior that is already legally mandated."); see also 1992 Policy Statement at 61,594. Order 679-A, P 25 (nexus test "ensure[s] that incentives are not provided in circumstances where they do not materially affect investment decisions").

[96] While Order 679-A, P 122 did not categorically disqualify mandatory projects from risks and challenges-based incentives if an applicant demonstrates nexus (recognizing the relevance of such mandate to establishing nexus), the Commission made clear that base ROE should generally be sufficient. *See* Order 679, P 94 (routine investments to comply with reliability standards "have, as a general matter, been adequately addressed through traditional ratemaking because there is an obligation to construct them and high assurance of recovery of the related costs. For these and other reasons, traditional ROE determinations may continue to be appropriate for these investments.").

all, benefits-based ROE incentives should be reserved for exemplary, voluntary projects. Otherwise, the Commission is awarding TOs extra profits, above and beyond the base ROE, for doing exactly what they are otherwise required to do, contrary to the purpose of Section 219 and its requirement that rates be just and reasonable.[97]

The NOPR (P 64) appears to properly recognize the voluntariness requirement when it proposes that projects to maintain an adequate level of reliability, as required by Section 215's mandatory reliability standards, should be ineligible for reliability-benefit incentives. But implementing the voluntariness requirement for such projects requires more. For example, as Order 679 recognized, reliability projects required by Section 215 can have economic impacts.[98] To avoid improperly granting incentives for mandatory projects, the Commission must prohibit awards of economic-benefit incentives to projects needed to maintain an adequate level of reliability. And any final rule must require applicants for economic or technology incentives to back out the benefits and costs of any project elements necessary to maintain reliability first, before assessing any benefits (and costs) for purposes of incentives, so that any benefits-based incentives apply only to the non-mandatory portion of the project.[99]

The NOPR also improperly fails to consistently adhere to the voluntariness requirement by not expressly ruling out incentives for other types of mandatory projects. For example, TPs have long been required to expand the system to provide requested

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[97] *See New England Power Pool*, 97 FERC ¶ 61,093, at 61,477 (2001) (incentive denied to avoid "unjustly reward[ing] NEP for doing what it is supposed to do").

[98] *See*, *e.g.*, Order 679, PP 41, 344.

[99] *See* Part VI.B.2 (discussing the treatment of mandatory projects for purposes of incentives for "above and beyond" reliability projects).

transmission and interconnection service on a non-discriminatory basis.[100] And TPs are required to plan and expand the grid, consistent with good utility practice, to comparably deliver a network customer's network resources to its network load.[101] Similarly, for an RTO to perform its required planning and expansion function, TOs that join RTOs must commit to undertake certain transmission system expansions when directed by the RTO,[102] thus making incentives unnecessary for such projects.[103]

Consistent with voluntariness requirements, the final rule should make clear that projects required by tariff or directed by RTOs should not be eligible for benefits-based incentives. As in the case of mandatory reliability projects, the costs and benefits of such projects must be excluded from consideration in granting any incentives. For example, an addition undertaken to satisfy transmission and interconnection service requests may reduce congestion and enhance reliability, but should not qualify for incentives.

Finally, the NOPR (at P 98) wrongly proposes to eliminate the existing voluntariness requirement for RTO participation. As discussed in Part X.B, the Commission's explanation for doing so cannot be harmonized with Section 219 or precedent. Through Section 219(d), Congress subjected all incentives, including the

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[100] *Pro Forma* OATT § 15.4; *Standard Large Generator Interconnection Agreement*, FERC, Articles 11.3 & 11.4.1 (Sept. 26, 2013), https://www.ferc.gov/sites/default/files/2020-04/LGIA.docx.

[101] *Pro Forma* OATT § 28.2.

[102] *See* 18 C.F.R. § 35.34(k)(7).

[103] The D.C. Circuit upheld pre-Order 679 ROE incentives based on a factual record showing the incentive would induce ISO-NE TOs to accelerate the projects, which acceleration would deliver "dramatic" quantified savings; consistent with this focus, incentives were limited to projects completed by a specified date. *Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d at 33-36. The court found that Commission's determination satisfied the rationally related "nexus" test based on uncontested findings of "exceptional value" given congestion and unreliability that produced a sense of urgency linked to the incentive. Because of the need to accelerate these projects, the court distinguished these essentially performance-based incentives from rewarding utilities for doing what they are supposed to do anyway, as barred by *New England Power Pool*, 97 FERC ¶ 61,093 (2001).

Section 219(c) incentive for joining an RTO, to the FPA's just and reasonable requirement. Requiring transmission customers to pay billions of extra dollars to TOs, for something certain TOs are already mandated to do, is unjust and unreasonable.

B. Benefits Must Be Clearly Defined and Quantified

The NOPR expressly invites applicant creativity on benefits claims, even proposing to consider qualitative benefits. If the Commission pursues the NOPR's approach to incentives, benefits to be considered must be clearly defined and quantified. The Commission's 1992 Policy Statement calls for quantification of consumer benefits to allow assessment of their value and the prospects for the benefit occurring, and to protect consumer interests as the FPA requires.[104] Although not required under Order 679's risks and challenges approach where benefits were addressed only as a threshold issue, adherence to the 1992 Policy Statement's quantification requirements takes on far greater importance if the Commission awards incentives based on evaluation of claimed benefits.

Clear delineation and quantification of benefits and calculation methodologies are essential to avoid double-counting benefits—a problem that the NOPR acknowledges (P 55), but also invites.[105] As discussed in Part II.A, TAPS questions whether layering multiple benefits-based ROE incentives onto the total investment in the same project up to the proposed 250-basis-point cap can ever be just and reasonable, particularly in the absence of any showing of need for the incentive. Regardless, the absence of clear delineation and quantification requirements to prevent any overlap in benefit metrics

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[104] See 1992 Policy Statement at 61,590, 61,600.

[105] *See*, *e.g.*, NOPR P 47 (seeking comments on "the merits of use of benefits-to-costs ratios to determine eligibility of transmission projects, regardless of the type of transmission project, for ROE incentives based on their economic benefits").

would be an obvious red flag, especially when considering additive incentives for both a project's economic benefits and its above-and-beyond reliability benefits.

C. Benefits-Based Incentives Must Take Greater Account of Costs and Continue to Exclude Cost Overruns

The NOPR proposes to allow *ex ante* Economic Incentives (based on projected costs in relation to projected benefits) and *ex post* Economic Incentives (based on actual costs in relation to projected benefits), and to apply these economic-incentive metrics to technology incentives (albeit without describing how that would be done). The NOPR, however, does not require any consideration of project costs with respect to reliability incentives; indeed, cost is never mentioned in the NOPR's description of its proposed reliability-benefit incentives. By failing to consistently consider actual costs in assessing benefits-based incentive applications, the NOPR's approach cannot possibly come close to producing just and reasonable rates.

To prevent incentives based on benefits that are tiny in comparison to project costs, any final rule should require, in addition to the quantification discussed in Part IV.B, that all benefits claims be presented in relation to costs. And all benefits-based incentives, including reliability incentives, should be predicated on meeting an aggressive benefit-cost ratio, with costs that include any requested incentives.

Any *ex ante* benefits-based incentives should also be provisional on actual costs. To receive any such incentive, applicants should be required to make a Section 205 filing that includes the project's final, actual costs (including the cost of any requested incentives) and demonstrates, using the benefits calculation on which the Commission provisionally awarded incentives, that the project achieves the benefit-cost ratio assumed in the *ex ante* grant of incentives. If actual project costs exceed the estimate used to award the incentives, the incentives should be subject to rescission or reduction.[106]

Conspicuously absent from the NOPR is any reference to the 2012 Policy Statement's (P 28) limitation of the application of incentives to budgeted amounts.[107] The NOPR suggests abandonment of this policy, providing that projects qualifying for an *ex ante* economic-benefit incentives may retain them regardless of cost overruns.[108] While the NOPR's proposed *ex post* economic incentive is based on a benefit-cost ratio that uses actual cost, it does not otherwise limit any incentive granted to the previously budgeted cost. As noted, the NOPR makes no reference to cost in describing its proposed reliability incentives.

Any final rule should reiterate adherence to this important consumer protection policy. The need for retaining the bar on applying incentives to cost overruns is heightened in the context of incentives that purport to be based on consumer benefits, which could be easily be eviscerated by cost overruns. The unexplained apparent departure from this policy, which has been applied in adjudications, is unlawful.[109]

D. Life-of-Facility Benefits-Based Incentives Without Accountability Are Not Just and Reasonable

There's a fundamental tension between granting ROE incentives based on benefits and allowing those incentives to remain in place throughout the life of the

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[106] *See* TAPS Initial NOI Comments at 37-38.

[107] *See also PJM Interconnection, L.L.C.,* 155 FERC ¶ 61,097, P 86 (2016), *on reh'g*, 158 FERC ¶ 61,060 (2017) ("an applicant is expected to commit to limit the application of such incentive ROE adder to a cost estimate").

[108] *See* NOPR P 60 ("regardless of cost overruns, an applicant would remain eligible for the ex-ante economic benefit ROE incentive.").

[109] *See, e.g., Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117.

facility without any demonstration that claimed benefits continue for that duration. Benefits may attenuate over time, especially with changes in the grid topology, loads, and resources. Benefits-based incentive advocates in the NOI proceeding stressed how hard it is to accurately estimate benefits over time.[110] Long-term estimates of reliability benefits—benefits that the NOPR states (PP 65, 68) cannot be measured in a single way or even quantified in some cases—are particularly suspect. Limiting ROE incentives to no longer than ten years, as suggested in TAPS' NOI Comments, would be more consistent with the feasibility of estimating the benefits on which the incentives are justified.[111] The NOPR's proposed five year limit on the obligation of those receiving benefits-based incentives to report actual economic benefits (NOPR P 125(f)) highlights the unreasonableness of burdening American consumers and businesses with elevated costs for the life of a project in return for benefits that cannot be demonstrated.

For the incentives proposed by the NOPR—which are expressly *not* based on the returns needed to induce investment in light of project risks and challenges not accounted

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[110] *See, e.g.*, Comments of Ameren Services Co. 26, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 26, 2020), eLibrary No. 20190626-5276 (after-the-fact reporting to assess whether benefits materialized is a "fruitless and a costly burden" because benefits can change over time as a result of many factors, and the scope of the project may change); Comments of Exelon Corp. 20, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 26, 2019), eLibrary No. 20190626-5229 ("applicant should not be punished if its good faith estimates of benefits do not come to fruition given the difficulties in accurately estimating benefits, changes in project use from the use anticipated when the project was developed, or other changed circumstances. . . . [E]conomic benefits of a transmission project will vary based on the prices of the fuels used in power production, changes in the generation resource mix, and changes in demand, among other factors."); Initial Comments of WIRES 12, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 26, 2020), eLibrary No. 20190626-5167 (benefits of transmission change over time due to various factors, but it would be highly problematic to reduce incentives if benefits diverge from those anticipated). *See also* Joint Comments of Public Interest Organizations on the Commission's Notice of Inquiry 38, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 26, 2020), eLibrary No. 20190626-5302 ("there will almost certainly be large discrepancies between forecasted and actual benefits because of changes in technology and cost (for example solar and batteries).").

[111] TAPS Initial NOI Comments at 40-41, 110.

for in the base ROE—life-of-facility incentives cannot be justified by investor reliance. TOs would still be assured recovery of their costs, plus a reasonable ROE, regardless. So long as the Commission is clear about the duration of any above-cost ROE adders and other incentives granted at the time they are awarded, any concerns regarding investor expectations and reliance would be fully addressed.

If any final rule does not limit benefits-based ROE incentives to ten years or less, accountability is required, with the incentive terminated or reduced if the projected benefits do not materialize or are not sustained at the level claimed when the Commission approved the incentives.[112] The Commission has previously denied implementation of ROE incentives where the factual predicate for the incentives grant was not achieved.[113] Failing to reduce or revoke incentives where the basis on which they were awarded no longer obtains would be arbitrary and inconsistent with the Commission's approach to other grants, e.g., market-based rates ("MBR");[114] standard of conduct waivers.[115] Any investor reliance concerns can be addressed by including an accountability regimen in the final rule or the order approving incentives.

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[112] See TAPS Initial NOI Comments at 111-13 (describing procedures for reporting material changes in the project for which incentives were granted and periodic measurement and verification of benefits, with elimination or reduction of incentives if claimed benefits are not sustained).

[113] *See Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, PP 51-55 (2018) (denying implementation of ROE incentives for project anticipated to span the PJM-MISO border that was unable to secure PJM approval).

[114] *See* 18 C.F.R. §§ 35.37 (requiring triennial submission of updated market power analyses), 35.42 (requiring timely reporting of any change in status departing from the characteristics relied upon in granting MBR authority), enabling the Commission to consider whether the grant should be revoked.

[115] *See Wolverine Power Supply Coop., Inc.*, 127 FERC ¶ 61,159, P 14 (2009) ("if the facts upon which the Commission relied in granting a request for waiver of Order No. 889 have changed such that the utility no longer meets the sales threshold applied to determine eligibility for the waiver, the Commission must reconsider whether waiver of the Standards of Conduct remains appropriate for the utility.); *Material Changes in Facts Underlying Waiver of Order No. 889 and Part 358 of the Commission's Regulations*, 127 FERC ¶ 61,141 (2009) (requiring notification of change).

Finally, if good behavior is to be rewarded with upward ROE adjustments (particularly if incentives are granted for the life of the facility, without accountability, as proposed), bad behavior merits a downward adjustment. Symmetrical incentives, as contemplated by the 1992 Policy Statement,[116] are necessary to avoid excessively burdening consumers or arbitrarily relying on an unfounded assumption that all TOs are performing at or above average. While the Commission declined to provide for symmetry as part of its risks and challenges approach,[117] in a benefit-based approach symmetrical incentives are necessary to balance consumer and investor interests.

E. The NOPR's Proposal Should Be Revised to Better Preserve and Protect the Planning and Competitive Development Process

If the Commission adopts the NOPR's benefits-based approach to incentives, it should at minimum include provisions to limit the resulting damage (discussed in Part II.B) to the transmission planning processes that the Commission and stakeholders have worked hard to develop and implement. Specifically, the Commission should:

- Require full participation and selection in applicable planning processes as a prerequisite for receiving benefit-based incentives. *See* Parts V.A, VI.B.4, XI.A.2.
- Assure that the adjusted production cost savings estimates or other metrics used in applications for benefit-based incentives are based on modeling and assumptions consistent with the applicable region's Order 1000 process for evaluating and selecting economic projects. *See* Parts V.B, XI.A.2.
- Base any Economic Incentives on actual costs, not just *ex ante* cost estimates. *See* Part V.C.
- Require that any benefit-cost evaluations include the cost of contemplated incentives. *See* Parts V.E, VI.B.3, XI.C, XII.

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[116] 1992 Policy Statement at 61,606-07.

[117] *See* Order 679, P 19; Order 679-A, P 130 (The Commission noted that Section 219 "does not rule out symmetrical approaches to return.").

- Require that all actual costs be included in *ex post* benefit-cost evaluations, as well as actual-cost confirmations of *ex ante* benefit-cost evaluations. *See* Parts IV.C, V.E.

The Commission should also take steps to expand competitive opportunities with respect to projects for which an incumbent transmission developer seeks benefit-based incentives. Order 1000 eliminated federal ROFRs for new transmission facilities selected in a regional plan for regional cost allocation.[118] But it left federal ROFRs in place for all other facilities, and did not seek to preempt state ROFRs.[119] As a result, non-incumbent developer competition has been limited to a very small percentage of the transmission projects constructed since Order 1000 issued.[120]

The NOPR's proposed ROE adders will exacerbate the problem by increasing the financial reward TOs receive for blocking competition, and incenting incumbent TOs to evade planning processes with competitive transmission development procedures. To avoid that outcome, foster competition, and support Order 1000's non-incumbent developer reforms, the Commission should require that incumbent transmission owners waive all applicable federal or state ROFRs as a prerequisite for applying for any benefit-based ROE incentives. To be effective, such waivers must be disclosed by the incumbent TO at the outset of the planning process, so that non-incumbent developers are aware of the opportunity to compete. Potential competitors must also have adequate time after the disclosure of the waiver to develop and submit their alternative proposals.[121]

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[118] Order 1000, P 313.

[119] *Id.* PP 318-19.

[120] *See* 2017 Transmission Metrics Report at 25-27.

[121] The Commission has recognized the need for these types of provisions in the hydroelectric licensing context, where potential applicants for new licenses may be deterred from submitting a competing application if they know that the incumbent licensee intends to seek a new license. The Commission's regulations therefore provide additional time for potential applicants other than the existing licensee to

As discussed in Part III, a limited exception to this waiver requirement should be provided in situations where the incumbent TO has, by offering a meaningful opportunity for inclusive joint ownership, agreed to forego a share of any above-cost incentives awarded to the project that transmission-dependent Open Access Transmission Tariff ("OATT")customers would otherwise be required to pay. Given the significant benefits joint ownership provides, encouragement of such arrangements through this limited exception is consistent with the Commission's obligations under FPA Sections 217 and 219(b)(1).

Placing a ROFR waiver condition on requests for benefits-based incentives would not alter the underlying federal or state ROFRs. Incumbent TOs would still be free to exercise those ROFRs so long as they do not seek ROE incentives. *See Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (upholding Order 2003's imposition of a non-discrimination provision on public utilities' exercise of state eminent domain power). Incumbent TOs, however, would not be able to apply for ROE incentives for a project while simultaneously barring competition from non-incumbents that could deliver a better project at lower cost. By opening up more projects to competition, the ROFR waiver requirement would help assure that the most efficient and cost-effective projects are constructed.

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submit a new license application, in certain cases where the incumbent licensee had indicated that it intended to file a license application, but then failed to do so. 18 C.F.R. § 16.25; *Hydroelec. Relicensing Regulations Under the Federal Power Act,* Order No. 513, 47 FERC ¶ 61,225, FERC Stats. & Regs. at 31,449-50 (1989), *on reh'g*, Order No. 513-A, 49 FERC ¶ 61,398 (1990). Similar provisions would be needed with respect to incumbent TO waivers of federal and state ROFRs.

F. The NOPR's Proposal to Maintain Existing Procedures Is Inconsistent with Achieving Just and Reasonable Benefits-Based Incentive Rates

If incentives are to be based on a Commission evaluation of project benefits, the methodologies for calculating benefits and the procedures for incentive application proceedings become central. Particularly because the NOPR allows for incentive awards based on quantifications beyond RTO-performed adjusted production cost savings calculations—including applicant-sponsored benefits quantifications, as well as applicant claims of qualitative benefits—there is a high risk of unjust and unreasonable rates. But the NOPR includes no procedures or other consumer protections to ensure that Congress' express directive that any incentives be "just and reasonable" is satisfied.

Evaluation of benefits brings with it enormous challenges. These include the need to verify amorphous and potentially overlapping claimed benefits, to exclude benefits associated with required upgrades for which no inducement is necessary or appropriate, and to avoid double-counting. The factual and modeling assumptions on which an applicant's benefit calculations rest—which will not in all cases have been vetted through a transparent Order 890 and 1000 planning process—must be evaluated as well.

In contrast to evaluating the risks and challenges faced by utilities, which is an integral part of the cost-based ratemaking analysis the Commission has performed for decades, the Commission has comparatively little experience with project benefit evaluations. In Order 1000, it declined to require that regional plans, which select projects for regional cost allocation based on benefit-cost analyses, even be filed with the

Commission, let alone approved.[122] And there is no equivalent to the Uniform System of Accounts for "benefits" to avoid double-counting and to assure consistency in record-keeping and the benefits analyses submitted to the Commission by incentive applicants.

Because benefits-based incentives are necessarily fact-and assumption-specific, applications must be scrutinized in formal proceedings that provide the Commission and intervenors with access to the information and modeling necessary to evaluate, reproduce, and contest the applicant's benefit claims. Information access is crucial for intervenors to meaningfully participate in proceedings where the Commission evaluates those claims. For example, the NOPR's rebuttable presumption for RTO benefit-cost analyses (P 50) would be effectively *un*rebuttable if lack of access to factual and modeling information and assumptions prevents effective and timely challenges. The information gap is particularly acute to the extent the Commission considers granting incentives based on non-RTO benefit-cost analyses, and invites alternative demonstrations of a wide range of benefits, both quantitative and qualitative.[123]

Despite proposing fundamental changes to the criteria and factual basis for incentives, the NOPR proposes no enhanced procedures to enable review of applicant benefit claims. The NOPR would continue existing "procedural flexibility," including allowing applicants to seek expedited declaratory orders. *Id.* P 40. That approach cannot be harmonized with Section 219(d)'s express directive.

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[122] Order 1000-A, P 191.

[123] It is instructive in the Section 205 context, the Commission has found issues of material fact warranting an evidentiary hearing based, among other things, on intervenor claims that there was insufficient information to conduct the fact-specific inquiry required to determine CWIP eligibility, which customers must have the opportunity to verify. *Duke Energy Carolinas, LLC*, 150 FERC ¶ 61,118 (2015).

Resolution of the complex factual and modeling issues associated with benefit-based incentives will necessitate disclosure requirements as an essential part of the application process,[124] along with providing a meaningful opportunity for evidentiary hearings (with ample time for discovery) to avoid arbitrary determinations and unjust and unreasonable rates. The fundamental FPA requirement that rates be just and reasonable cannot be satisfied by a process that effectively forecloses objection. Nor can material issues of fact be decided on the basis of pleadings.

V. ECONOMIC INCENTIVES

If the Commission, notwithstanding the fundamental defects discussed above, adopts the NOPR's proposed Economic Incentives, it should also include, as a supplement to the general prerequisites described in Part IV: (1) modifications necessary to mitigate the damage such incentives would inflict on planning-based approaches to transmission expansion that have successfully fostered dramatic increases in transmission in the past decade (Parts V.A – V.E); (2) changes to the NOPR's proposal to more appropriately define the quantitative thresholds used to determine whether Economic Incentives are warranted (Part V.F); (3) process and evidentiary requirements that are necessary, given the NOPR's reliance on a data- and modeling-intensive quantitative metric to award Economic Incentives (Part V.G); and (4) requirements to address discrimination in the implementation of these incentives, particularly in non-RTO areas and for local transmission projects (Part V.H).

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[124] *See* Parts IV.E, V.G, VI.B.4, and XII with regard to the timing and content of those disclosure requirements.

A. *The Commission Should Require Full Participation and Selection in Applicable Planning Processes as a Prerequisite for Benefits-Based Incentives*

The NOPR proposes to award ROE incentives to projects that demonstrate an economic-benefit-to-cost ratio that exceeds certain thresholds. Adjusted production cost savings "or similar measures of congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative" would be used to measure project benefits. NOPR P 48. Project costs used in the benefit-cost ratio would be based on estimated costs (for *ex ante* Economic Incentives) or actual costs (for *ex post* Economic Incentives).

If (despite TAPS objections) the final rule includes such Economic Incentives, the NOPR's proposal to use adjusted production cost savings to measure economic benefits for this purpose is a step in the right direction. As the NOPR correctly recognizes, the metric is used by all RTOs and some non-RTO regions to evaluate and select regional economic projects for regional cost allocation. *Id*. P 48. The NOPR acknowledges and purports to accommodate RTO concerns "that the Commission not impose a benefits-based incentives approach that would duplicate or interfere with their transmission planning efforts, cause inefficient use of RTO/ISO staff time, or engender contention and potential litigation." *Id*. P 44. And its proposed rebuttable presumption for economic benefits measured in RTO-derived benefit-cost ratios (P 50) properly prefers existing economic analyses by independent transmission providers over *ad hoc* studies developed by applicants to justify an ROE adder award for an individual project.[125]

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[125] As discussed in Part V.B, the NOPR, P 54, would still allow Economic Incentives to be awarded based on *ad hoc* studies developed by individual incentive applicants.

Nevertheless, there is still too much light between the projects selected in transmission plans and those eligible for Economic Incentives under the NOPR's proposal. In contrast to planning processes that seek to select the best project or combination of projects to meet transmission needs, the NOPR appears to envision awarding substantial ROE incentives to multiple, potentially competing and incompatible individual projects, many of which have *not* been selected in transmission plans or perhaps even been considered or evaluated in any planning process.

Providing substantial financial subsidies for the construction of projects *not* determined to be the most cost-effective and efficient is a giant misstep. As discussed in Part II.B, the Commission has worked for more than a decade to develop and enhance transmission planning processes to ensure just and reasonable rates, prevent undue discrimination, and get "the *right* transmission facilities" built.[126] To avoid undermining these planning processes, any benefits-based incentives should be designed to both encourage participation in planning processes and reinforce their results. The following principles should be adopted:

- *Where a project would qualify to be considered for selection in the Order 1000 regional plan for regional or interregional cost allocation, the Commission should not grant incentives unless the project has gone through the applicable planning process* *<u>and</u>* *has been selected by the planning process for regional cost allocation.* The Commission's incentives should not encourage project developers to end-run regional planning processes; only projects determined by those processes to be the most efficient and cost-effective should be eligible for any benefits-based incentive.

- *For transmission projects that do not qualify for consideration for regional cost allocation under the applicable Order 1000 process (e.g., based on voltage, scope, and other criteria defined by the particular regional planning process), full*

[126] Order 1000, P 50 (emphasis added). Order 679-A, PP 41, 46-50, and the 2012 Policy Statement, PP 25-27, also rightly recognize the value of the regional process in evaluating alternatives (through the rebuttable presumption and the expectation of a demonstration of consideration of alternatives).

participation and selection in the applicable Order 890 planning process should be a prerequisite for any request for benefits-based incentives. The Commission's incentives system should not encourage project developers to avoid the Order 890 open, transparent planning process, with an opportunity for early input from stakeholders that will have to bear the project costs, including any incentive.

- *If a project has not been vetted through an Order 890-compliant process, no benefit-based incentives should be granted.* For example, under current Commission precedent, only projects that "expand the grid" are required to be considered in Order 890 processes; "asset management projects and activities [that] do not expand the grid" do not fall within Order 890's requirements. *Cal. Pub. Utils. Comm'n v. PG&E*, 164 FERC ¶ 61,161, P 66 (2018), *reh'g denied*, 168 FERC ¶ 61,171 (2019). Under this principle, TOs that choose not to subject their sub-regional projects to an Order 890-compliant process would not be eligible for benefit-based incentives for such projects.

B. Economic-Benefit Estimates Must Be Based on Modeling and Assumptions Consistent with Order 1000 Processes for Evaluating and Selecting Economic Projects

At the November 2019 GETs Workshop, panelists representing the RTOs and independent market monitors ("IMMs") all agreed that economic-benefit modeling is highly dependent on underlying assumptions, and cannot accurately quantify the future benefits from proposed projects.[127] Panelists stated that RTO benefits calculations are sufficient to enable transmission planners to evaluate the *relative* benefits of competing

[127] *See*, *e.g.*, GETs Tr. Day 2, 312:7-16 (Patton, Potomac Economics) ("The idea that you could calculate benefits that are even close to accurate, especially when you go out in time, it's just not realistic. We've evaluated some of the cost benefit studies that have been done, especially these two that New York talked about, and you get beyond five years and the benefits are just 5, 10 years, especially 10 years, the benefits are almost worthless, they just go to mush because there are so many assumptions that you have to make about not only the topology, but field prices and what generators are entering and exiting."), *id.* 321; 316:24–317:2 (Glazer, PJM) ("Can we calculate [the benefit]? Yes. What you then do with the calculation in terms of setting rates is I think those two are very different questions. I wouldn't answer the second one the same way as the first one."); *id.* 317:21–318:18 (Millar, CAISO) ("our economic evaluations are an important part of our transmission planning process . . . . We do put a lot of effort into that . . . . But to take one of those and say well we at the ISO are going to put a pin in this one and say that is valid for ratemaking purposes, we would have a lot of trouble with that . . . We could . . . follow a very prescribed set of assumptions and say okay, we will do the math for you, but that's where it would end because the long-term responsibility for that being a valid number for a very specific forecast, very specific set of outcomes, and landing on a long-term rate based on that, I think we would have trouble defending that ourselves as a credible value."); *id.* 320:7-10 (Bowring, Monitoring Analytics) ("So, yes, of course, [the RTO] can do [benefits] calculations, but they're wrong, and they're not going to be right over time and they're not a good basis for compensating people."); *See also* Leovy Statement at 12.

alternatives, but using those methodologies to calculate an *absolute* level of benefits for use in setting a rate would be inappropriate.[128] As Neil Millar of the CAISO succinctly summarized, "I think we would have trouble defending that ourselves as a credible value."[129]

Because the absolute level of economic benefits predicted by an adjusted production cost savings study, or any other measure of congestion reduction, is so dependent on the study's assumptions, a system that awards incentives based on *ad hoc* analyses of individual applicants (as the NOPR, P 54, would allow) does not just invite abuse, it virtually guarantees it. The NOPR's proposed economic-benefit ROE adders would be a compelling financial incentive for each applicant to design its study model to maximize the adjusted production cost savings it can claim for its project. And in the absence of a requirement to apply consistent assumptions and modeling across all such studies, the NOPR's incentives will likely end up rewarding the creativity of applicants and their consultants, rather than the actual economic benefits of proposed projects.

The NOPR's proposal to develop and apply national benefit-cost thresholds to determine when Economic Incentives will be awarded (*id*. PP 56-59) is also improper unless the Commission also requires: (1) consistency in the RTO economic benefit

[128] *See supra* note 57. *See also* GETs Tr. Day 2, 317:20–318:18 (Millar, CAISO); *id*. 319:1-4 (Lin, NY ISO) ("In FERC Order [1000], the projects are compared against each other, not necessarily just on a benchmarking case, so we were able to come up with meaningful results from there."); *id*. 288:18–289:3 (Glazer, PJM) ("If we now link the incentive to the individual cost benefit analysis we're doing, I guarantee you every one of those will be litigated . . . . If we're going to litigate the cost benefit on each one of those because now there's all these ratemaking incentives, we're going to be sitting here two-three years from now regretting what we did."); *id*. 308:15-21 (Bowring, Monitoring Analytics) ("[T]he idea that benefit sharing . . . is an appropriate way to do incentives technology is incorrect."); *id*. 239:18–240:1 (Leovy) ("[T]his is a significant problem . . . with these incentives proposals is that we're basing incentives on something that's difficult to estimate.")

[129] GETs Tr. Day 2, 318:16-17.

evaluation methodologies used to develop the national thresholds; and (2) that individual incentive applications use the same benefit metrics as the RTO benefit-cost analyses used to develop the national thresholds. According to the NOPR, the benefit-cost thresholds for receiving Economic Incentives will be based on "new national benefit and cost data." *Id.* P 56. In fact, the sample data and initial threshold calculations shown in Appendix A of the NOPR appear to include a mix of project-specific benefit-cost results developed using a variety of different RTO methodologies. *Id.* P 57. Absent an analysis demonstrating that the differences between the various RTO benefit-evaluation methodologies are *de minimis*, combining project data from multiple RTOs without adjusting the benefit estimates to a common basis is inappropriate.

The NOPR, moreover, would allow incentive applicants to submit economic-benefit studies that use "adjusted production cost, similar measures of congestion reduction, and certain other quantifiable benefits that are verifiable and not duplicative." *Id.* P 50. To the extent that RTO benefit-calculation methodologies underlying the national thresholds exclude an applicant-proposed benefit measure, allowing applicants to include such measure improperly stacks the deck. It will result in inflated individual project benefit-cost ratios that are more likely to exceed any national thresholds simply because the thresholds are based on a narrower definition of economic benefits.

To prevent these unjust and unreasonable outcomes, any final rule that includes incentives based on economic benefits must impose safeguards: (1) to tether all economic-benefit studies used to justify incentives to a consistent set of reasonable assumptions about future loads, grid topology, fuel prices, generator entrance and exit, study period, discount rate, and other factors; and (2) to require consistency in benefit metrics between incentive applications and the RTO planning analyses on which the benefit-cost cut-offs used to award such incentives are based. Specifically, **for projects eligible for consideration in the applicable Order 1000 *regional* process**:

- The Commission should limit the type and level of benefits claimed by incentives applicants to those quantified through an open, transparent Order 1000 planning process in which alternatives were considered and evaluated.
- The economic-benefit metrics used by an applicant must be consistent with the metrics used in the relevant Order 1000 process for that project. Alternative applicant-developed economic-benefit calculations should not be considered.
- An incentives applicant should not be allowed to claim Economic Incentives based on a benefits metric unless and until the applicable Order 1000 process for the project has been modified or expanded to include consideration of that metric for purposes of selecting economic projects for regional cost allocation.[130]

***Local* projects** ineligible to be considered for selection in the applicable Order 1000 process should be subject to requirements that assure economic-benefit claims are based on reasonable and consistent modeling assumptions. For example, where there is an open and transparent Order 890 planning process that uses a consistent, Commission-approved methodology to compare transmission and non-transmission alternatives based on adjusted production cost savings, the economic benefits claimed by an applicant should be required to be consistent with the adjusted production cost savings calculated for that project in the applicable Order 890 process.

[130] While the NOPR notes (P 48 & n.53) that at least one non-RTO region uses adjusted production cost savings to estimate economic benefits in its Order 1000 regional planning process, others do not. Peninsular Florida's Order 1000 process, for example, does not consider production cost savings as part of its evaluation of regional economic projects: the region's TPs argued that the metric is too speculative and divisive and should not be used, and the Commission declined to require it. *Tampa Elec. Co.*, 148 FERC ¶ 61,172, PP 90, 405, 425 (2014), *on reh'g and compliance*, 151 FERC ¶ 61,013 (2015). In regions where TPs have been unable to reach consensus on how to implement adjusted production cost modeling for purposes of regional transmission planning, it is inappropriate to use such modeling as a basis for awarding Economic Incentives.

For local projects that have *not* been evaluated by a robust Order 890 planning process that uses a Commission-approved methodology to calculate economic benefits and compare transmission and non-transmission alternatives, applicants should face a heavy burden. Such applicants: (1) should only be allowed to claim a benefit-based incentive for a local project based on adjusted production cost savings (or any alternative economic-benefit metric), if the Order 1000 process for the relevant region includes consideration of that metric for purposes of selecting economic projects for regional cost allocation; and (2) should be required to demonstrate that the adjusted production cost model (or alternative economic-benefit metric) it used to estimate benefits from the local project is consistent with the assumptions and modeling used in the relevant region's Order 1000 planning process for economic projects.

C. Any Economic Incentives Should Be Based on Actual Costs, Not Just **Ex Ante** *Cost Estimates*

The NOPR proposes to award a 50-basis-point incentive to projects that meet or exceed periodically determined benefit-cost ratio thresholds on an *ex-ante* basis—i.e., based on a pre-construction comparison of estimated adjusted production cost saving benefits to estimated project costs. NOPR P 57. But construction cost estimates are unreliable, and any system that grants significant financial subsidies based on low-ball cost estimates will encourage gaming. And even for developers that provide backup calculations showing how their estimates were derived, the unit costs claimed *ex ante* by transmission developers seeking incentives will be impossible to verify without detailed information on labor rates and the terms of the developer's agreements with contractors. The proposal to award developers 50 extra basis points if their estimated costs are significantly lower than their estimated benefits will compound these problems, encouraging developers to submit highly optimistic—if not downright misleading—cost estimates, and greatly expanding the number and type of projects for which cost estimates will need to be scrutinized for accuracy.

To protect against such abuses, *ex ante* Economic Incentives should be limited to developers willing to put their money where their mouth is by committing to a binding, comprehensive and fully inclusive cost containment provision at the level of the cost estimate used to calculate the *ex ante* benefit-cost ratio.[131] And if *ex ante* Economic Incentive awards are not completely eliminated for other developers, they should be made provisional: i.e., the applicant awarded an *ex ante* ROE incentive should be required to make a Section 205 filing upon completion of construction that includes the project's final, *actual* costs and confirms, using the benefits calculation on which the Commission provisionally awarded incentives, that the project still achieves the benefit-cost ratio threshold used to justify the original award.

D. All Actual Costs Should Be Included in **Ex Post** *Benefit-Cost Evaluations, as Well as in Actual-Cost Confirmations of* **Ex Ante** *Benefit-Cost Evaluations*

In response to the NOPR's inquiry (P 60), as a general matter any final rule should *not* exclude costs resulting from "factors beyond a developer's control from the ex-post analysis for an ex-post economic benefits ROE incentive." Such costs should also

[131] *See* Comments of TAPS 10-12, *Competitive Transmission Development Technical Conference*, Docket No. AD16-18-000 (Oct. 3, 2016), eLibrary No. 20161003-5264, urging development of a standardized cost containment provision that is comprehensive and fully inclusive (i.e., no hidden loopholes or exemptions), and should separately state the ROE, the capital structure, and any incentives the developer may seek. Such transparent, cost-contained bids would facilitate informed comparison, as well as an understanding as to exactly how the developer envisions the cost containment provision would operate when incorporated in its proposed rate.

be included in any *ex post* analyses conducted, as TAPS recommends, to confirm the appropriateness of *ex ante* Economic Incentives.[132]

Rate incentives adopted by the Commission must be "for the purpose of benefitting consumers."[133] Neither fairness nor any statutory directive or valid policy concern supports treating projects that are actually expensive for consumers as if they were cheap—and then awarding above-cost subsidies, which will further drive up consumer prices, based on that imaginary cheapness. If consumers will be expected to foot the bill for actual project costs that exceed the *ex-ante* cost estimate, all such costs must be included in any *ex post* analysis used to support an Economic Incentive.

The proposed dichotomy between "factors beyond a developer's control" versus those within a developer's control also makes no sense in the context of transmission development. Siting and constructing transmission always involves risks and factors beyond the developer's control. Indeed, a core function of a successful transmission developer is to anticipate, manage, and mitigate those risks. Developers, for example, can increase the accuracy of *ex ante* project cost estimates and reduce risk of cost overruns by collecting additional site-specific information and incorporating it into more detailed engineering plans. They can reduce siting risk by entering into broad-based joint ownership arrangements. In contrast, a standard that excuses "factors beyond a developer's control" could actually encourage developers to discount or ignore risks associated with their project, secure in the knowledge that they will recover their full

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[132] *See* Part V.D. As also described in Part V.D, the Commission should retain its current policy of barring application of incentives to cost over-runs.

[133] FPA Section 219(a).

costs, regardless, and will be eligible for ROE adders for "economic benefits," even if inevitable and easily anticipated cost overruns destroy any such benefits for consumers.

Finally, a loophole for "factors beyond a developer's control" will turn every application for *ex post* Economic Incentives into an opportunity for litigation, driving up administrative costs.

While TAPS does not support excluding any actual costs from *ex post* benefit-cost evaluations, should the Commission nevertheless allow such exclusions, it should at minimum restrict them to situations when the developer has demonstrated that it took all appropriate steps to avoid cost overruns from unexpected factors beyond its control. For example, because broad-based joint ownership has a proven track record in facilitating prompt, favorable state siting decisions,[134] a limited exclusion for excess costs associated with state siting difficulties might be appropriate *if* the developer has offered such joint ownership and taken other appropriate steps to reduce siting risk.

Absent these types of conditions, excluding costs from *ex post* economic-benefit analyses will invite moral hazard behavior by developers. Particularly in conjunction with the NOPR's proposal to continue the Abandoned Plant Incentive (Part VIII), the result will be projects proposed without adequate due diligence, more speculative project cost estimates, and more projects with either large cost overruns or abandoned when "factors beyond a developer's control" emerge. These outcomes, which are wasteful and will undermine public support for transmission projects, can and should be avoided.

[134] *See* Part III.

E. The Cost Element of Benefit-Cost Evaluations, Both **Ex Ante** *and* **Ex Post***, Must Include the Cost of Any Contemplated Incentives*

Consistent with Section 219(a)'s directive that any incentive rates be "for the purpose of benefitting consumers," the analyses used to justify incentive awards should focus on *consumer* costs and *consumer* benefits. The NOPR's proposed hefty ROE adders will directly increase the transmission rates paid by consumers, dollar-for-dollar. Thus, in answer to the NOPR's question (PP 57, 114), their full costs must be considered in the benefit-cost evaluations used to determine whether incentives are warranted.

Specifically, at the time projects are submitted for consideration in the applicable planning process, each transmission developer should be required to make a binding declaration of the incentives that it is reserving the option to request from the Commission. Failure to reserve a specific incentive would waive the right to request it, unless the project is resubmitted in a new planning cycle. The benefit-cost evaluation used in the applicable transmission planning process—and in any subsequent developer application for Economic Incentives—would then incorporate (and be limited to) the full cost of the incentives that the developer had declared. This approach is essential to achieve the transparency required by Order 890,[135] and to avoid a bait-and-switch under which projects are selected for inclusion in local and regional plans based on claimed costs that are significantly lower than their actual costs once the NOPR's proposed subsidies are included. While TAPS urges the Commission to consider Economic Incentives only for projects selected in regional and local plans (s*ee* Part V.A), even if

[135] *See*, *e.g.*, Order 890, PP 435, 471.

that recommendation is not adopted, the NOPR's incentives should not be allowed to distort or undermine the accuracy of planning studies and processes.

Fully reflecting the cost of the NOPR's proposed subsidies in planning and benefit-cost evaluations is also crucial to competitive transmission development, which the Commission has worked hard to foster and is starting to show results. In New England, for example, competition is attracting lower-priced transmission; Anbaric recently bid a 7.9% ROE in ISO New England's first competitive solicitation.[136] MISO's Hartburg-Sabine Junction 500 kV Selection Report[137] likewise showed stiff competition, with the non-incumbent-TO winner (NextEra) coming in below MISO's scoping bid and below the median bid, with an ROE fixed at 9.8% with 45% equity, foregoing CWIP and AFUDC, and a limit on ATRR and O&M costs over the first ten years.[138] The Commission should not deal a death blow to these promising developments by skewing the evaluation of benefit-cost ratios so that projects laden with costly incentives are treated as if they are less expensive than they actually are.

F. The NOPR's Proposed Benefit-Cost Thresholds Should Be Raised to at Least the 90th Percentile and Should Be Subject to a One-Way Ratchet

While TAPS supports the goal of using an objective, quantitative measure to determine eligibility for any Economic Incentive, the NOPR fails to establish benchmarks that assure only exceptional projects warranting a special financial reward will receive them. Instead, the NOPR's ROE incentives for projects with economic benefits would

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[136] Garrett Hering, *Anbaric Unveils Details of Offshore Wind Transmission Proposal for Boston Area*, S&P Global (Mar. 23, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/anbaric-unveils-details-of-offshore-wind-transmission-proposal-for-boston-area-57697002.

[137] MISO Selection Report .

[138] *Id.* at 5-6, 21.

forever grant incentives to the top 25% (*ex ante*) and top 10% (*ex post*) of projects, regardless of how low the benefit-cost ratios for those thresholds fall when the Commission recalculates them every five years. NOPR P 57-59.

In light of record evidence demonstrating high levels of transmission investment since 2012, and the NOPR's failure to demonstrate that current levels are inadequate,[139] awarding Economic Incentives on this basis is arbitrary. The NOPR's proposed standard for its *ex ante* Economic Incentive—i.e., a threshold set at the 75th percentile of economic projects previously evaluated by RTOs, the equivalent of a C+—is simply too low to be considered exemplary. Awarding extra profits to a quarter of all transmission projects both fails Section 219(a)'s mandate that any incentives be "for the purpose of benefitting consumers," and imposes unreasonable burdens on businesses and households at a time when budgets are already stretched by the economic fallout of the COVID-19 pandemic. While the Commission has failed to demonstrate the need for *any* ROE incentives based on economic benefits, the 90th percentile threshold proposed for the NOPR's *ex post* incentive, the equivalent of an A-, is at least arguably more defensible.

In addition, and regardless of whether it raises all thresholds for awarding an ROE adder based on economic benefits to at least the 90th percentile, the Commission should impose a one-way ratchet on any threshold to assure that the standards for granting such incentives are maintained over time. For example, even assuming that awarding an ROE incentive were appropriate for the top 10% of projects at the current 90th percentile benefit-cost ratio as currently calculated, the benefit-cost ratio associated with the 90th percentile could easily fall in future Commission threshold calculations as more

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[139] *See* Part I.

transmission is built and the steepest congestion-based price differentials are resolved. Continuing to award the same ROE incentive to the top 10% of new projects, even as overall standards and the absolute economic benefits from those projects decline, would be arbitrary and capricious, even assuming (incorrectly) that the proposed 100 basis points of total Economic Incentives were otherwise just and reasonable.

A one-way ratchet—a rate mechanism with a long history in wholesale rates[140]—would help address this problem. For example, the Commission's initial analysis would place the 90th-percentile benefit-cost thresholds at 5.17 for large projects and 77.04 for small projects. NOPR P 59. Under the ratchet approach, the Commission would reevaluate those thresholds in five years; and if the newly calculated 90th percentile thresholds are *lower* than 5.17 and 77.04, then the thresholds would not change. If the newly calculated 90th percentile thresholds are *higher* than 5.17 and 77.04—say 6.50 and 80.00—then the thresholds would rise to that level, which would then set a new floor for the next reevaluation in five years. Such a ratchet is necessary to assure that current minimum standards for transmission projects meriting incentives are not diminished over time.

G. Process and Evidentiary Requirements for Economic Incentives

The NOPR asks for comments on (P 52):

> current RTO/ISO practices with regard to the dissemination of production cost modeling information and the derivation of benefit-to-cost ratios and whether these practices could hamper an applicant from using the RTO/ISO modeling results to seek an ROE incentive for economic benefits.

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[140] *See*, *e.g.*, *Commonwealth Edison Co.*, 23 FERC ¶ 61,219, 61,470-71, *reh'g denied*, 24 FERC ¶ 61,055 (1983).

It also requests comments on "what supporting information and analysis an applicant's benefit-to-cost study should include." *Id.* P 54.

While the Commission's question in Paragraph 52 is focused on RTO information dissemination practices for would-be incentive applicants, information access and sharing will likely pose even greater challenges for customers. And it will be most acute in non-RTO areas and with respect to local transmission projects not currently evaluated by RTO planning processes. At present, most Order 1000 processes in non-RTO regions and most Order 890 processes do not systematically consider adjusted production cost savings. For those regions and projects, adequate dissemination of production cost modeling information is only a secondary issue—the main problem is that the basic data and models needed to perform such studies have never been assembled and validated.

Regardless, the Commission must assure that all information, assumptions, and analysis relied upon by incentive applicants—including but not limited to any RTO information on production cost modeling and the derivation of benefit-cost ratios—are made available to the Commission and to the transmission customers who would pay the cost of the incentives. The information provided must be sufficient for the Commission and customers to confirm and reproduce the benefit-cost study used to justify the incentive. Where the applicant relies on "economic benefits measured in RTO-derived benefit-cost ratios derived by RTOs" (NOPR P 50), RTO information adequate to reproduce those economic-benefit measurements should be provided. Imposition of these disclosure requirements is even more important to the extent the final rule enables applicants to develop their own adjusted production cost savings calculation or other benefit measures to support their incentives requests, where the NOPR (P 54) rightly places a higher burden on applicants to support analyses that are susceptible to manipulation.

Particularly given the NOPR's proposal to allow expedited proceedings for incentive applications (*id.* P 40), all supporting information must be included in the applicant's initial incentive submittal, if not earlier. Indeed, the level of information required for the Commission and customers to effectively evaluate claimed benefits highlights the inadequacy of such expedited processes and the need for an evidentiary hearing, with discovery. *See* Part IV.F.

H. Discrimination Concerns for Regional Projects in Non-RTO Areas and for Local Projects Not Evaluated by an RTO

The proposal to award ROE incentives for adjusted production cost benefits shines a spotlight on the issue of *who* will benefit from the transmission projects that receive the NOPR's proposed subsidies. Particularly in non-RTO regions and for local transmission projects that are not evaluated by an RTO, there is a substantial likelihood that the projects for which incumbent TOs seek and receive incentives will be designed to benefit primarily, if not exclusively, the TO that has proposed them. The adjusted production cost modeling used to justify the incentive award might even confirm that.

This problem of discriminatory transmission expansion planning is compounded by the fact while OATT customers will pay the NOPR's incentives-inflated rates, the TO's own bundled retail customers will only do so if the state public service commission chooses to include the incentive in those retail rates. In other words, OATT customers may well be the only loads paying the NOPR's above-cost Economic Incentives for a project designed to benefit the TO's retail customers.

OATT customers should not be required to pay above-cost incentives to projects from which they receive trivial or no benefit. *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009); *Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014). The Commission, at minimum, must ensure that the economic benefits incented by ROE adders flow to the entire footprint required to pay for those adders—including OATT customers—and not just the incumbent utility's retail customers.[141]

VI. RELIABILITY INCENTIVES

A. The Commission Should Not Adopt the Proposed Reliability Incentive

The NOPR proposes to offer a Reliability Incentive of up to 50 basis points for transmission projects "that produce significant and demonstrable reliability benefits above and beyond the requirements of the NERC reliability standards."[142] The NOPR does not propose any limits on how such benefits can be demonstrated, and provides no support for why projects that provide *more* than an adequate level of reliability warrant an incentive ROE. It identifies some examples of reliability benefits that could count, but states that those examples are "nonexclusive," that other qualitative benefits can be considered, and that commenters should propose even more types of reliability benefits that should count.[143] Nor does the NOPR propose any way of distinguishing exemplary projects that will be considered "significant" from run-of-the-mill projects that will not qualify for incentives. And cost is never mentioned in describing its Reliability Incentive.

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[141] As discussed in Part III, if the TOs receiving Economic Incentives have made meaningful offers of inclusive joint ownership, that provides evidence the projects incented by the NOPR's economic-benefit ROE adders do not discriminate in favor of the incumbent utility seeking the incentive.

[142] NOPR P 64.

[143] *Id*. PP 66-72.

The Commission should not adopt the proposed Reliability Incentive, which does not comply with Section 219. First, it provides no evidence that an incentive is needed to "promote" any prudent investment above-and-beyond an adequate level of reliability.[144] Second, because the proposed incentive does not consider a project's cost, the Commission cannot make the required determination that the Reliability Incentive and resulting rates are just and reasonable. Third, the proposal does not offer any discernable standard for evaluating whether a project's above-and-beyond benefits are "significant," which invites arbitrary decision-making and limits the Commission's ability to compare competing incentive proposals. Finally, it creates misaligned incentives, encouraging TOs to minimize investment in meeting reliability requirements so that they can qualify for above-and-beyond incentives for projects they would otherwise have built.

1. The Commission's cost recovery policies already make above-and-beyond reliability projects attractive, low-risk investments

The NOPR cites no evidence demonstrating benefits-based ROE incentives are needed to promote above-and-beyond reliability projects.[145] In fact, there is strong evidence that public utilities are already eager to invest in above-and-beyond reliability projects which they view as attractive, low-risk investments without such incentives. Nick Akins, CEO of AEP, for example, stated that investments in resiliency and reliability of the grid are "really probably one of [the] least risky investments we can make."[146] Widespread adoption of formula rates combined with the Commission's

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[144] Section 219(b)(1) (requiring the Commission's rule to "promote reliable . . . transmission").

[145] As the NOPR (P 64) concedes, "additional transmission incentives are not necessary to maintain an adequate level of reliability."

[146] Technical Conference Transcript 78:18-19, *Security Investments for Energy Infrastructure Technical Conference*, Docket No. AD19-12-000 (Apr. 26, 2019), eLibrary No. 20190426-4001 ("Grid Security

"presum[ption] that all expenditures are prudent"[147] significantly reduces the risk that public utilities will not recover costs related to improving reliability beyond what is required by mandatory standards.

Public utilities are already making substantial investments in such projects. EEI estimates that electric utilities have invested $285 billion in transmission and distribution since 2012 to harden the grid and make it more resilient.[148] That trend will continue, with EEI estimating that "about a quarter of electric company transmission spending through at least 2021 is expected to be devoted to improving resilience and security, as well as to integrating advanced technologies."[149]

As discussed in, the FPA authorizes the Commission to grant ROE incentives only to those projects that need an incentive to be built. Granting additional equity returns for above-and-beyond projects that would be built without that extra ROE "is a handout, not an incentive."[150] And given the large investments already being made, fueling the frenzy to augment transmission rate base by adding ROE incentives for still more investments claimed to produce *more* than an adequate level of reliability cannot be squared with fundamental FPA requirements.

Tr.").

[147] *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, P 100 (2017) , *on reh'g*, Op. No. 554-A, 170 FERC ¶ 61,050 (2020), *petition for review dismissed sub nom. Potomac-Appalachian Transmission Highline, LLC v. FERC*, No. 20-1086, 2020 U.S. App. LEXIS 18392 (D.C. Cir. June 10, 2020).

[148] *Smarter Energy Infrastructure: The Critical Role and Value of Electric Transmission*, EEI, 3 (Mar. 2019), https://www.eei.org/issuesandpolicy/transmission/Documents/2018%20Smarter%20Energy%20Infrastructure%20The%20Critical%20Role%20and%20Value%20of%20Electric%20Transmission.pdf.

[149] *Id.* at 5.

[150] Glick Dissent P 4.

2. By failing to take any account for costs, the proposal is unable to comply with the requirement that incentives result in just and reasonable rates

The NOPR proposes to reward "significant and demonstrable reliability benefits" (P 65), while completely ignoring associated costs. Cost is never referenced in describing the proposed Reliability Incentive. The only mention of cost in the entire Reliability Benefits section of the NOPR is in Paragraph 64, where it cites Section 219(b)(4)(A) as assuring recovery of all prudent costs for projects to comply with NERC reliability standards.

The NOPR's focus on benefits to the exclusion of costs is inconsistent with its stated purpose of aligning to the statutory language of "benefiting consumers."[151] It also conflicts with the NOPR's objective of "better align[ing] incentives awarded with transmission project benefits *and costs*."[152] And it violates Section 219, which gave no directive to completely ignore cost to consumers in granting incentives, potentially for large and unduly expensive projects that have a net negative value to consumers. To the contrary, by making all incentives subject to Section 219(d), Congress made clear that assuring just and reasonable rates was an overriding obligation.

Without considering a project's cost, the Commission cannot determine that a project is prudent,[153] much less that an ROE incentive is warranted and the resulting incentive-inflated rates are just and reasonable. No prudent organization would authorize

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[151] NOPR, P 32.

[152] *Id.* P 33 (emphasis added).

[153] *New England Power Co*., 31 FERC ¶ 61,047, at 61,082 (1985) (regulated rates may not "compensate for extravagant or unnecessary costs") (citing *Acker v. U.S.*, 298 U.S. 426, 430 (1936)), *reh'd denied*, Op. No. 231-A, 32 FERC ¶ 61,112 (1985), *petition for review denied sub nom. Violet v. FERC*, 880 F. 2d 280 (1st Cir. 1986).

projects without regard to costs, and without considering if there were less expensive alternatives. To grant ROE incentives to a project without insisting that it achieves an impressive benefit-to-actual-cost ratio, or even considering whether the project's cost exceeds quantifiable above-and-beyond reliability benefits, would be fundamentally at odds with the FPA's overarching obligation to protect consumers from excessive rates.[154]

By encouraging projects that provide reliability in excess of what is required for an adequate level of reliability in compliance with NERC standards while ignoring costs, the proposal invites utilities to gold-plate their systems. Chairman Chatterjee has acknowledged the need to balance costs and benefits to avoid gold-plating.[155] Without any consideration of cost, the proposed incentive cannot "identify the sweet spot" that Chairman Chatterjee—and presumably the Commission—is aiming to hit.

It would be unjust and unreasonable to require ratepayers to pay for a project with costs that exceed its benefits, let alone pay for an incentive on top of the cost. In the case of ROE incentives—which add to the cost of projects *not* needed to achieve an adequate level of reliability—it is doubly important to weigh the project's cost and benefits to ensure just and reasonable rates, as required by Section 219(d). The NOPR appears to take that basic legal requirement seriously for the economic-benefit and technology ROE incentives, by making benefit-cost ratios an explicit factor in determining a project's eligibility. Yet, for the Reliability Incentive, the NOPR inexplicably fails to even

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[154] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 781 (2016) (quoting *Penn. Water & Power Co. v. FPC*, 343 U.S. 414, 418 (1952)); *see also Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959) (affording customers "a complete, permanent, and effective bond of protection from excessive rates and charges"). *See also* Part II.A.

[155] Grid Security Tr. ("But obviously, building transmission can also be very expensive, so how do we identify that sweet spot where we reduce the criticality of individual facilities but we're not gold-plating the system?").

consider cost, let alone making cost an explicit factor in determining eligibility. The proposal is therefore contrary to the statute and must be rejected.

3. The proposal lacks any standard for assessing reliability benefits or any mechanism to compare competing incentive applications to determine which projects are most merit-worthy

The NOPR proposes to grant Reliability Incentives to projects with "significant and demonstrable" reliability benefits "above and beyond" the adequate level of reliability required by NERC reliability standards. But while the proposal includes a laundry list of non-exclusive ways (quantitative and qualitative) for an applicant to demonstrate reliability benefits,[156] it provides no indication of how the Commission will evaluate claimed benefits and determine whether they are significant. Unlike the proposed Economic Incentives—which require a project to have a benefit-cost ratio above a specified cut-off—the proposed Reliability Incentive includes no mechanism to ensure only the best-of-the-best projects are awarded an above-cost ROE adder.

This amorphous incentive should not be adopted. First, the proposal fails to provide the increased certainty that the NOPR identifies as a basis for its proposed reforms.[157] If, for example, an applicant were to demonstrate that a transmission project would increase import capability between balancing authorities by 5%, would the Commission find that to be a "significant increase"?[158] Would it depend on current levels of import capability? Anticipated demand? Without any meaningful standard, applicants

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[156] NOPR PP 68-73.

[157] *Id*. P 33.

[158] *See id*.7 P 68 ("transmission projects that *significantly* increase import or export capability between balancing authorities can provide significant and demonstrable reliability benefits" that may be eligible for the incentive) (emphasis added).

will have no certainty about which projects will qualify for the incentive. The problem is even worse for claimed benefits that are more difficult to quantify.

Second, lack of a meaningful standard all but invites arbitrary decision making. The NOPR proposes that the Commission will make case-by-case evaluations, but making such determinations without reference to any meaningful standard will lead to protracted litigation about the validity of the claimed benefits and the basis for any "significan[ce]" finding. That reliability benefits are difficult to quantify argues strongly against adopting benefits-based incentives, but does not excuse the Commission from articulating clear—much less any-- expectations up front, if it pursues that approach.

Finally, without any standard for assessing reliability benefits (and by failing to consider cost), the proposal cannot compare competing incentive applications to determine which are the most merit-worthy and cost-effective. When faced with dozens of Reliability Incentive applications each year, how will the Commission determine which projects are eligible? And for how many basis points? Unless the Commission puts meaningful parameters on that question by rule, it will be faced with significant challenges to ensure incentives are not unduly discriminatory.

4. The proposal creates misaligned incentives, encouraging TOs to minimize investment in meeting reliability requirements so that they can qualify for above-and-beyond incentives for projects they would otherwise have built

As explained above, the Commission's cost recovery policies amply induce transmission owners to make investments that exceed minimum reliability requirements. The NOPR, while intended to encourage such investments, could have the perverse result of actually discouraging the investments that are already occurring. A transmission owner that would have made a prudent investment as part of its normal, pro-active compliance with its obligation to provide an adequate level of reliability consistent with reliability standards would be financially motivated not to do so, and instead to later propose a more expensive project to qualify for an above-and-beyond ROE incentive.

Consider an extreme example. TPL-001-4 requires a utility to develop a Corrective Action Plan when its analysis indicates an inability of its system to meet the standard's performance requirements.[159] Although the NERC standard permits such Corrective Action Plans to include the installation of a remedial action scheme,[160] good utility practice and applicable planning criteria may warrant construction of new facilities as a more robust solution. Indeed, some planning criteria prohibit the use of a remedial action scheme in certain situations.[161] Under the NOPR's proposal, a utility seeking to maximize profit would have an incentive to include a remedial action scheme in its Corrective Action Plan, claim that the scheme is all that is required to comply with the NERC standard, and then propose a transmission project to eliminate the newly created remedial action scheme, seeking an incentive for going above and beyond an adequate level of reliability.[162] Absent potential availability of the Reliability Incentive, the ability to earn its Commission-regulated return on equity on additional transmission facilities would have been a strong incentive reinforcing adherence to good utility practice.

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[159] N. Am. Elec. Reliability Corp., Standard TPL-001-4, R. 2.7, *Transmission System Planning Performance Requirements* (2005), https://www.nerc.com/files/TPL-001-4.pdf ("TPL-001-4").

[160] TPL-001-4, R. 2.7.1.

[161] *See, e.g., LG&E/KU Transmission System Planning Guidelines*, LG&E/KU, § 8.1 (Oct. 29, 2019), http://southeasternrtp.com/docs/planning_criteria/LGE-KU-Planning-Criteria.pdf ("LG&E/KU Transmission System Planning Guidelines") ("Neither SPS(s) nor . . . remedial action schemes should be considered when developing the Corrective Action Plan(s).").

[162] *See* NOPR P 71 (stating that the elimination of a remedial action scheme is the kind of benefit that would qualify for an incentive).

Section 219 does not authorize the Commission to create a financial motive for utilities to engage in practices that erode reliability and violate good utility practice. Such an incentive clearly does not "benefit[] customers by ensuring reliability."[163]

B. If the Commission Nevertheless Adopts the Reliability Incentive, it Must Impose Additional Safeguards to Comply with the Federal Power Act

1. The Commission should make clear that projects undertaken to comply with NERC standards and applicable planning criteria are ineligible for incentives

The NOPR (P 64) appropriately finds that "transmission incentives are not necessary to maintain an adequate level of reliability," which is the statutory objective of reliability standards.[164] It goes on to propose ROE incentives for "certain projects that produce significant and demonstrable benefits above and beyond requirements of the NERC reliability standards." NOPR P 64. If the Commission adopts some version of the proposal, it should expressly include, within the scope of projects *in*eligible for incentives, those undertaken, consistent with good utility practice required by tariff, to comply with NERC standards and applicable planning criteria. A narrower exclusion would conflict with the Commission's long-standing interpretation of reliability projects and well-established industry practice in planning for reliability, and would make the grid less reliable by encouraging band-aids instead of durable solutions to reliability violations.

The need for clarification arises because consistent with Section 215(i)(2), which bars NERC and the Commission from "order[ing] the construction of additional . . .

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[163] Section 219(a).

[164] *See* FPA Section 215(c)(1) (establishing, as a criterion for Electric Reliability Organization certification, "the ability to develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system.").

transmission capacity," NERC's principal reliability standard for transmission planning—TPL-001-4—does not directly require a transmission owner to construct any new projects. That standard establishes a set of performance requirements for specified types of contingency events,[165] and requires transmission planners to develop a Corrective Action Plan when studies indicate that the system will not be able to meet those performance requirements.[166] While a Corrective Action Plan *may* include the installation or modification of transmission facilities to meet these performance requirements, TPL-001-4 permits alternatives, such as dropping load or implementing other operational workarounds (*e.g*., limiting the output of generation),[167] although doing so may not be consistent with good utility practice. Thus, if read unduly narrowly, the NOPR's proposed exclusion from above-and-beyond incentives of projects "required to comply with" NERC standards could be argued to exclude *no projects at all*.

The final rule should expressly reject such an unreasonable interpretation. The NOPR clearly did not intend for projects "necessary to maintain an adequate level of reliability" to be a null set. NOPR P 64. To do so would be fundamentally at odds with the way the Commission, as well as RTOs and TOs, have viewed responsibility for planning projects to comply with NERC standards.

For example, in requiring public utility TPs to participate in a planning process that produces a regional plan to evaluate more efficient and cost effective solutions than those identified in local transmission plans, the Commission expressly targeted

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[165] TPL-001-4 at 8 tbl.1 (defining P0 through P7 contingency events and performance requirements for each).

[166] *Id.* R 2.7 (requiring a Corrective Action Plan when Table 1 performance requirements are not met).

[167] *Id.* R 2.7.1 (describing the types of actions that can be included in a Corrective Action Plan).

"transmission facilities needed to meet reliability requirements."[168] And in requiring public utility TPs to propose ex ante cost allocation for new facilities selected for cost allocation in regional plans, the Commission included "transmission facilities needed for reliability" among the three types of additions that must be addressed.[169] The Commission did not impose these requirements for "transmission facilities needed to meet reliability" requirements as a hollow gesture.

In response to the NERC compliance concerns of TPs in the event a selected non-incumbent developer abandons a project "meant to address a [NERC] violation," Order 1000 set forth explicit compliance and mitigation procedures that, if followed, would shield public utility TPs from enforcement action for those NERC violations.[170]

In addition, in addressing RTO Order 1000 compliance filings that proposed exemption from competition for "transmission facilities that are needed in a short time frame to address reliability needs (i.e., immediate need reliability projects)," the Commission allowed a limited exemption from Order 1000's elimination of the federal ROFR for projects selected for regional cost allocation "to avoid delays in the development of projects needed to resolve a time-sensitive reliability criteria violation" if specified criteria were satisfied.[171] In its order initiating Section 206 investigations as to

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[168] Order 1000, P 148; s*ee also id.* P 2 ("support[ing] the development of those transmission facilities identified by each planning region as necessary to satisfy reliability standards.") .

[169] *Id.* P 586 (Regional Planning Principle (6)).

[170] *Id.* P 344.

[171] *ISO New England,* 169 FERC ¶ 61,054, P 3 (2019) (citing Order 1000 compliance orders for the various RTOs).

whether several RTOs were properly administering this limited exemption, the Commission summarized the criteria as requiring (among other things) that: [172]

> (i) The project must be needed in three years or less to solve reliability criteria violations . . .;
>
> (ii) The [RTO] must separately identify and then post an explanation of the reliability violations and system conditions in advance for which there is a time-sensitive need, with sufficient detail of the need and time-sensitivity. . .;
>
> (iii) The RTO must provide to stakeholders and post on its website a full and supported written description explaining: (1) the decision to designate an incumbent transmission owner as the entity responsible for construction and ownership of the project, including an explanation of other transmission or non-transmission options that the region considered; and (2) the circumstances that generated the immediate reliability need and why that need was not identified earlier.

It would be completely inconsistent with the Commission's limited exemption for immediate need reliability projects for the Commission to now allow incentives on projects designed to address violations of reliability criteria on the theory that NERC standards do not directly require construction.

To be consistent with Order 1000 and what has long been recognized as good utility practice required by Commission tariff,[173] any final order should explicitly

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[172] *Id.* In its recent order finding that PJM had failed to adhere to the Commission-established criteria for immediate need reliability project exemption, the Commission reaffirmed that the criteria "appropriately maintain the balance between reliability and competition." *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,212, PP 15-16 (2020). *See also* orders finding other RTOs compliant, *ISO New England, Inc.*, 171 FERC ¶ 61,211, P 63 (2020), and *Southwest Power Pool, Inc.*, 171 FERC ¶ 61,213, P 49 (2020).

[173] *See Policy Statement on Matters Related to Bulk Power System Reliability,* 110 FERC ¶ 61,096, P 1 (2005) ("the Commission interpret[s] the term 'Good Utility Practice' as that term is used in the *pro forma* [OATT] to include compliance with reliability standards developed by [NERC].").

recognize that projects to comply with regional and TO planning criteria that implement NERC transmission planning standards[174] are not eligible for the Reliability Incentive.

Specifically, projects selected through an RTO's transmission planning process to meet a reliability need should be not eligible for incentives. For example, MISO's Transmission Expansion Plan identifies Baseline Reliability Projects as those that are necessary to "ensure that the Transmission System is in compliance with applicable national [ERO] reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region."[175] Any project MISO designates as a Baseline Reliability Project is, by definition, necessary to maintain reliability and should be ineligible for an incentive. Every RTO has similar requirements for reliability-driven solutions, which should similarly be ineligible.[176]

Outside RTOs, projects developed to comply with NERC standards, as interpreted and implemented through local planning criteria, should be ineligible for the Reliability

[174] *See* TPL-001-4, R 5 (requiring each Transmission Planner and Planning Coordinator to "have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response.").

[175] MISO Tariff, Attachment FF §II.A.

[176] PJM's Regional Transmission Expansion Planning Protocol Projects are those that are needed to ensure compliance with PJM criteria for system reliability, operational performance or economic criteria. PJM's system reliability criteria "shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation and SERC, and other Applicable Regional Entities." PJM Operating Agreement, Schedule 6 §1.2(d). NYISO's Reliability Planning Process identifies reliability needs, which are conditions that are "violation[s] or potential violation[s]" of "policies, standards, criteria, guidelines, procedures, and rules promulgated by the. . . [NERC], Northeast Power Coordinating Council, and the New York State Reliability Council." NYISO OATT, Attach. Y §§ 31.1. CAISO's Transmission Planning Process defines a Reliability Driven Solution as a project that is "required to ensure System Reliability consistent with all Applicable Reliability Criteria [i.e., NERC and WECC standards and any utility-specific reliability criteria] and CAISO Planning Standards." CAISO Tariff § 24.4.6.2; *id.* App. A. SPP's Transmission Planning Process operates pursuant to planning criteria "comprised of the NERC Reliability Standards and SPP Criteria." SPP OATT, Attach. O § II.4.i. In ISO-NE, Reliability Transmission Upgrades are projects that are "necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards, which include "those established by the ISO, NERC, and [Northeast Power Coordinating Council]." ISO-NE OATT, Attach. K § 4.1 and *id*. Attach. N § II.A.

Incentive. For example, Louisville Gas & Electric Company and Kentucky Utilities Company (collectively, "LG&E/KU") have adopted Transmission System Planning Guidelines "in accordance with NERC Reliability Standard TPL-001-4" that "establish[] the minimum planning criteria for the LG&E/KU Transmission System."[177] Any projects developed to meet those planning criteria are necessary to maintain an adequate level of reliability, consistent with good utility practice, and should be ineligible for incentives.

Any final rule should, in addition to confirming that transmission projects built to comply with regional and transmission owner planning criteria that implement the NERC transmission planning standard are not eligible for incentives, include an express warning that the Commission: (1) will closely examine changes that narrow the scope of those planning criteria; and (2) will deny incentives for a project if a utility has narrowed its planning criteria in order to characterize the project as above-and-beyond applicable requirements. To support that effort, applicants seeking incentives should be required to identify any changes to their planning criteria for reliability projects since issuance of the NOPR and demonstrate that the project for which incentives are being sought (or a more limited project avoided by the proposed project) would not have been required under the previous planning criteria. This would minimize adverse reliability impacts arising from the proposed incentive, discussed in Part VI.A.4.

Consistent with the NOPR's recognition of the inappropriateness of granting incentives for required reliability projects, any final rule should also exclude from incentives projects required to comply with other requirements, including additions to

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[177] LG&E/KU Transmission System Planning Guidelines § 1.

meet tariff transmission and interconnection obligations and to comply with RTO directives, as discussed in Part IV.A.

2. The Commission should evaluate only the incremental benefits provided above and beyond whatever project would have been required to meet reliability needs and apply the incentive only to the incremental costs above what it would have cost to build a project that maintains an adequate level of reliability

The NOPR appropriately finds that projects built to maintain an adequate level of reliability are not eligible for the Reliability Incentive. As an essential corollary to the NOPR's correct finding, the Commission should clarify that: (1) only project benefits above and beyond the adequate level of reliability may count towards eligibility for the incentive, and (2) the incentive will apply only to the project's incremental cost above what it would have cost to build a project that maintains an adequate level of reliability. Both clarifications are necessary to prevent gaming the incentive regimen to secure incentives for projects needed to satisfy reliability criteria.

Consider a $100 million project that is needed to maintain an adequate level of reliability. If the developer added a $1 million bell or whistle to the project that resulted in additional reliability benefits, the developer could apply for the Reliability Incentive. For the Commission to evaluate and grant above-and-beyond ROE incentives as to the $101 million combined project would be plainly unjustified. First, the Commission should only consider the project's incremental benefits (i.e., the benefits associated with the $1 million project addition) when assessing whether the project is eligible for the incentive. Second, if the Commission grants the incentive, it should apply only to the incremental $1 million cost associated with exceeding the applicable reliability requirements.

Application of these critical limitations highlights the flaw in the NOPR's proposal (P 72) to grant the Reliability Incentive to transmission projects that use network management technologies. If a large project were ineligible for the Reliability Incentive because it is needed to maintain an adequate level of reliability, a developer should not be allowed to circumvent that exclusion by tacking on network management technology and then claiming a Reliability Incentive on the value of the entire transmission project. Instead, the cost of the project that would have been necessary must be removed before applying the Reliability Incentive.[178] To do otherwise would allow the tail to wag the dog and invite gaming. Thus, any final rule should not permit an entire transmission project to receive Reliability Incentives based on the addition of technology.

To implement these necessary clarifications, the Commission should require applicants for a Reliability Incentive to identify any project otherwise required to assure an adequate level of reliability that is subsumed within or avoided by the above-and-beyond project, and provide the estimated cost that would have been incurred for such project, along with back-up for that estimate sufficient to enable customers and the Commission to verify it. That information would allow the Commission to determine the incremental cost and incremental benefit of the proposed project.

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[178] As discussed in Part XI.D, developers should also be barred from obtaining both the Reliability and Technology Incentives for the exact same technology, which would be impermissible double-counting. Therefore, if the developer has received the NOPR's Technology Incentives for the network management technology, it should be ineligible for the Reliability Incentive for any above-and-beyond reliability benefits provided by that technology.

3. The Commission should require that an applicant demonstrate that a project's quantifiable above-and-beyond reliability benefits significantly exceed its incremental cost

As discussed in Parts VI.A.2 and VI.A.3, the NOPR provides no standard by which the Commission will determine whether a project's claimed above-and-beyond reliability benefits are "significant," and does not consider a project's cost when determining eligibility for the incentive. To address those failures, the Commission should make consideration of cost and thus, net benefits, an essential feature of its evaluation whether claimed benefits are sufficiently significant and demonstrable to warrant an incentive, and adopt a structure (similar to the NOPR's Economic Incentives) in which an applicant must demonstrate that a project's quantifiable, above-and-beyond benefits exceed its cost by an established threshold ratio so only projects that produce exemplary net benefits are rewarded.

First, it is essential that the calculation consider net, incremental benefits. As discussed in Part VI.B.2, the cost and benefits of a project needed for an adequate level of reliability must be removed from the calculation of an above-and-beyond project's benefit-cost ratio for the purpose of evaluating the incentive.

Second, the incremental benefits used in the benefit-cost analysis must be quantifiable; that is the only way the Commission can meaningfully compare benefits to costs. As discussed in Part VI.A.3, the difficulty of quantifying reliability benefits does not excuse the Commission from its obligation to ensure rates are just and reasonable when adopting a benefits-based incentives regimen.

Third, the Commission should develop a standard set of metrics that can be used to quantify above-and-beyond reliability benefits before granting incentives on claimed benefits. TAPS recognizes that there is currently nothing equivalent to the adjusted production cost metric, honed by RTOs over time, that could be used to assess the value of projects that provide *more* than an adequate level of reliability. While that is a compelling argument against adopting the proposed incentives, if the final rule nevertheless incorporates the NOPR's proposal, the Commission should not invite a "free for all." It should establish a standardized set of quantifiable, above-and-beyond reliability benefits that will be used to evaluate a project's benefit-to-cost ratio. If the Commission concludes that regional differences make a single, nation-wide method unworkable, it should establish a method for calculating the quantifiable, incremental benefits that is consistent across TOs in the same region and would not be unduly discriminatory among regions. Finally, the Commission should establish an aggressive threshold benefit-to-cost ratio that a project must meet to be eligible for the Reliability Incentive, so only exemplary projects are rewarded.

4. The Commission should require that, to be eligible for the incentive, a project be vetted in an adequate Order 890 planning process, and the applicant waive all state and federal ROFRs

The NOPR's incentives for above-and-beyond reliability benefits are particularly improper because such projects are excluded from existing planning and competitive development processes which the Commission has relied upon: (1) to support findings that the projects to which it awards incentives are beneficial;[179] and (2) to discipline

[179] Order 679-A established a limited rebuttable presumption that a project will qualify for incentive rate treatments if it results from a regional planning process or has been approved by a state commission or siting authority, and the applicable process considered whether the project ensures reliability or reduces congestion. Applicants must also satisfy all other requirements before being granted incentives, such as demonstrating nexus between the incentive sought and the investment being made. Order 679-A, P 50.

transmission project costs and assure that the right projects are planned and built.[180] Order 1000 planning processes are designed to "support the development of those transmission facilities identified by each transmission planning region *as necessary to satisfy reliability standards*, reduce congestion, and allow for consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations."[181] Projects the NOPR targets for Reliability Incentives—i.e., "transmission projects that produce significant and demonstrable reliability benefits *above and beyond* the requirements of the NERC reliability standards" (NOPR P 64 (emphasis added))— are not included in that scope.

In issuing Order 890, the Commission likewise focused on assuring adequate and nondiscriminatory planning of transmission upgrades "to *maintain reliability*" and to "reduce the overall costs of serving native load," including by reducing congestion costs or integrating efficient new resources."[182] Order 890 did not preclude TPs from including in their transmission planning processes projects with above-and-beyond reliability benefits, and some Order 890 processes may be broad enough to encompass them. Such projects, however, were not specifically discussed by Order 890, and many approved Order 890 processes may be inadequately tailored to address them.

Above-and-beyond reliability projects are also generally excluded from competitive transmission development processes. Because Order 1000 processes do not

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[180] *See*, *e.g.*, Order 1000, P 43 (transmission planning reforms were intended to remove impediments to "the development of beneficial transmission lines," to avoid "inefficient and overlapping transmission development due to a lack of coordination" and to "obtain[] more efficient or cost-effective transmission service."); *see also id.* PP 50, 78-84, 284, 289.

[181] Order 1000, P 2 (emphasis added).

[182] Order 890, P 542 (emphasis added); *see also id.* PP 595, 599.

plan for regional above-and-beyond reliability needs, they do not solicit competing projects to address them. And while certain Order 1000 processes might allow a competitively selected regional project to displace a local above-and-beyond reliability project in limited circumstances,[183] Order 1000's non-incumbent reforms and regional competitive development processes do not apply to local projects.[184] Thus, above-and-beyond reliability projects are neither systematically vetted by existing Commission-approved transmission planning processes nor subject to any competitive discipline.

TAPS strongly recommends against a generic directive requiring modification of existing Order 1000 processes to include above-and-beyond reliability projects. The NOPR does not demonstrate any need for *regional* above-and-beyond projects, let alone incentives to subsidize and encourage the construction of such projects or a sweeping change to existing regional planning processes.

Sub-regional above-and-beyond reliability projects, if made eligible for incentives at all, should at minimum be integrated into applicable Order 890 processes. Although many sub-regional Order 890 processes lack clear, rigorously applied planning criteria, they serve important transparency and procedural functions. TOs seeking incentives for above-and-beyond projects should therefore be required to conduct an open, transparent process to provide transmission customers, their RTO (if applicable) or Order 1000 regional planning process, neighboring TOs, non-incumbent transmission developers, and

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[183] The Order 1000 process for peninsular Florida, for example, provides for "identify[ing] and evaluat[ing] whether there are more efficient or cost-effective regional transmission solutions relative to the transmission facilities in the initial regional transmission plan." *Tampa Elec. Co.*, 148 FERC ¶ 61,172, P 92 (2014). Because the initial regional transmission plan is created by consolidating the individual local plans of the region's Transmission Providers, above-and-beyond reliability projects included in local plans would be evaluated and might be displaced as part of the Order 1000 process.

[184] Order 1000, PP 317-319.

other stakeholders with detailed information about any such projects prior to submitting an incentive application. Information required to be provided should include, without limitation: (1) a detailed description of the proposed project; (2) an explanation of how the project exceeds the applicable reliability requirements; (3) a detailed explanation of the TO's study process for evaluating such above-and-beyond projects, including data sources and modeling; and (4) an estimate of the above-and-beyond project's incremental benefits and incremental costs (including a detailed description and analysis separating out the elements of the above-and-beyond project that are needed to satisfy NERC reliability standards).

Projects that are not vetted through the full Order 890 process—e.g., based on TO claims that they are exempt "asset management" projects[185]—should be ineligible for any Reliability Incentive. To the extent an individual TO's existing, Commission-approved Order 890 process does not already encompass above-and-beyond projects and provide for the information and process described above, the TO should be required to amend that process before applying for a Reliability Incentive for any project.

Integrating consideration of sub-regional above-and-beyond projects into Order 890 processes will facilitate the Commission's assessment of the TO's incentive application, because stakeholders will have had an opportunity to review and analyze the data prior to its filing with the Commission. And it should allow TPs participating in the Order 1000 regional planning process—including the RTO, if applicable—to assess the

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[185] *See, e.g., Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161, P 65 n.119 (2018), *reh'g denied*, 168 FERC ¶ 61,171 (2019) (2018) (defining asset management projects, not subject to Order 890 planning processes, as "maintenance, repair, and replacement work done on existing transmission facilities necessary to maintain a safe, reliable, and compliant grid based on existing topology.").

potential reliability and operational impacts of the proposed above-and-beyond project. As the Commission correctly recognized when it imposed a disclosure requirement on merchant transmission developers that did not seek to take advantage of Order 1000's cost allocation mechanisms, "[b]ecause all electric systems within an integrated network are electrically connected, the addition or cancellation of a transmission project in one system can affect the nature of power flows within one system or on other systems.[186]

Advance disclosure through an open, transparent process, including to the applicable regional planning process, could also enable limited competition for such projects—at least to the extent certain existing Order 1000 processes allow local projects included in individual TO plans to be displaced by competitively selected regional projects. And as discussed in Part IV.E, the Commission should encourage that competition by requiring that any application for above-and-beyond incentives be conditioned on the incumbent TO waiving all applicable state and federal ROFRs for the relevant project. It is fundamentally unfair to grant above-cost ROE adders to TOs that simultaneously use a ROFR to block competitors; that is literally the definition of a monopoly rent. Because these projects, by definition, are not needed to satisfy applicable NERC reliability standards and implementing planning criteria, there can be no argument that their urgency precludes a competitive development process. As discussed in Parts III and IV.E, a narrow exception to the ROFR waiver requirement could be allowed if the TO offers inclusive joint ownership in the project.

[186] Order 1000, P 163.

5. The Commission should clarify that it will favorably consider meaningful offers of inclusive joint ownership.

In evaluating Reliability Incentive applications, the Commission should favorably consider meaningful offers of inclusive joint ownership to transmission dependent utilities that must pay rates that fund the upgrade. Because "above and beyond" projects are not needed to meet reliability standards, heightened scrutiny is necessary to assure the project is not gold-plating and provides significant benefits to the system as a whole. Inclusive joint ownership offers, particularly if accepted, are a strong indication that LSEs in the footprint are supportive of the project and recognize its benefits.

Inclusive joint ownership would also mitigate objections to the project and its proposed incentives as discriminatory. If ownership is broadly shared by all LSEs in the footprint, concerns that the project may be designed to disproportionately benefit the TO's retail customers are significantly reduced. And such arrangements mitigate the potential for rate disparities and cross-subsidies from wholesale to retail customers if the relevant state commission chooses not to increase a TO's bundled retail rates to reflect the transmission incentive. Given the added challenges an incentives-laden above-and-beyond project may face in the state siting process, inclusive joint ownership could play an important role in securing state approvals, as discussed in Part III,.

6. An evidentiary hearing is particularly essential to evaluate claimed above-and-beyond benefits and should include prudence.

The Commission establishes evidentiary hearings in cases with a "genuine issue of fact material to the decision."[187] Evaluating potential above-and-beyond reliability benefits, especially in the absence of any limitation on the nature of the benefits claimed

[187] 18 C.F.R. § 385.217(b).

or any standard methodology for quantifying benefits, will necessarily be a fact-intensive inquiry. This effort is complicated by the need to determine and exclude the cost and benefits associated with subsumed projects that would have been required to maintain an adequate level of reliability, as well as issues about the accuracy of underlying assumptions. As discussed in Part IV.F, an evidentiary hearing with the opportunity for discovery will be essential to permit the fair and full evaluation of each applicant's incentive request, and its justness and reasonableness, that the FPA requires.

In addition, any final rule allowing above-and-beyond incentives should make clear that applicants will not only bear the burden of demonstrating the significant benefits warranting incentives, but will also face Commission scrutiny as to the project's prudence. The Commission's general policy "in order to ensure that rate cases are manageable" is to "presume[] that all expenditures are prudent so the utility need not justify in its case-in-chief the prudence of all of its costs."[188] That presumption of prudence does not apply when Commission "policy[] or precedent require otherwise" or when "a party creates serious doubt as to the prudence of an expenditure."[189]

In the case of Reliability Incentive applications, which focus on above-and-beyond projects, the rationale for the presumption is not present. Placing the burden on customers to create serious doubt about a project's prudence is unwarranted where the applicant admits that the project is more than is necessary to maintain reliability. Any final rule should provide that the presumption of prudence will *not* apply to projects seeking the Reliability Incentive. Including prudence within the scope of incentive review

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[188] *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, P 100 (2017).
[189] *Id.*

process will expose incentive applicants to downside risk, discouraging applications for projects whose net benefits are marginal.

7. The Commission should not allow a project to be eligible for the Reliability Incentive if the project qualifies for the Economic Incentives

Many, if not all, projects that qualify for the Economic Incentives will also provide some reliability benefit. In some cases, transmission projects will be designed to meet an adequate level of reliability *and* reduce adjusted production costs,[190] but in many cases, a project designed to reduce adjusted production costs will result in a higher level of reliability than is required by applicable reliability standards and criteria. Given the NOPR's unrestricted opportunity to claim wide-ranging benefits as a basis for incentives, an applicant could recast a project's economic benefits as above-and-beyond reliability benefits and seek both Economic and Reliability Incentives.

Double-counting of the same underlying benefit to obtain two different incentives would be unjust and unreasonable. Consider an economic project that reduces adjusted production costs by increasing import capacity from a neighboring balancing authority. If the economic benefit-to-cost ratio meets the threshold established in any final rule, the developer could seek the Economic Incentive. The developer might also claim that the same increase in import capacity has reliability benefits, because it helps prevent load shedding.[191] In such case, the project would be creating a single benefit,[192] but would be able to qualify for two benefit-based incentives.

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[190] *See, e.g.* MISO Tariff, Attach. FF § II.C.2.c (Criterion 3 Multi-Value Projects are those that "address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones.").

[191] *See* NOPR P 68 (describing potential load shedding avoidance benefits from increased import capability

As discussed in Parts II and IV.B, to avoid unjust and unreasonable results, a project qualifying for Economic Incentives should be ineligible for the Reliability Incentive.

8. The Commission should not consider resilience benefits when assessing the reliability benefits of a project.

The NOPR proposes to "consider transmission projects that improve resilience in awarding reliability incentives."[193] However, resilience is not one of the objectives enumerated in Section 219, and thus the Commission cannot grant incentives for enhancing resilience except to the extent that such projects "promote reliable . . . transmission and generation of electricity."[194]

Although there is some overlap with reliability, the "concept of resilience necessarily involves issues, topics, and questions that extend beyond the Commission's jurisdiction, such as distribution system reliability and modernization."[195] The Commission's Section 215 jurisdiction is limited to the bulk power system ("BPS"), which expressly excludes distribution facilities.[196] The Commission cannot give incentives for projects that improve resilience of distribution facilities, which are subject to the jurisdiction of state and local regulators.[197] Even for BPS facilities, the FPA

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from a neighboring balancing authority).

[192] The intended outcome of increasing the import capacity would be that operators use that added capability, in which case the transmission path will remain loaded leaving the system with lower cost dispatch, but similar reliability. Alternatively, the capacity wouldn't be used, increasing reliability but failing to produce the expected economic benefits.

[193] *Id*. P 73.

[194] Section 219(b)(1).

[195] *Grid Resilience in RTOs & ISOs*, 162 FERC ¶ 61,012, P 19 n.31 (2018).

[196] Section 215(a)(1) ("The term [BPS] does not include facilities used in the local distribution of electric energy.").

[197] State and local regulators are already actively addressing distribution system resilience issues.

focuses on reliable operations to protect against "instability, uncontrolled separation, or cascading failures" that result from a "sudden disturbance . . . or unanticipated failure of system elements."[198] Although the Commission has yet to define resilience, its proposed definition is broader.[199]

VII. ELIMINATION OF THE ZONE OF REASONABLENESS AND SUBSTITUTING A 250-BASIS-POINT CAP

The NOPR proposes "a 250-basis-point cap for all ROE incentives," regardless of whether the total ROE is within the zone of reasonable returns.[200] It correctly identifies a need to establish a fixed cap on ROE incentives, but the proposed cap is exorbitant. And the NOPR inappropriately removes the requirement that the total ROE remain in the zone of reasonable returns. To be consistent with Section 219, the Commission should: (1) impose a fixed cap of no more than 100 basis points on project-specific adders and no more than 50 basis points for RTO participation and, in addition (2) retain the cap on total ROEs at the top of the zone of reasonable returns. In any event, the Commission should not eliminate the zone of reasonableness cap that was placed on previously granted ROE incentives.

A. The Commission Should Reduce the Fixed Cap on Incentive ROEs to No Higher Than 100 Basis Points of Project-Specific Adders, Plus No More Than a 50-Basis-Point RTO Adder

The proposed 250-basis-point cap on ROE incentives is excessive. First, Section 219 allows for ROE incentives sufficient to "attract[] new investment in

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[198] Section 215(a)(4), *id.* § 824*o*(a)(4).

[199] NOPR P 73 n. 74 ("the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.") (citation omitted).

[200] *Id.* P 80.

transmission facilities (including related transmission technologies)," but "subject to the requirements of [Sections 205 and 206] that all rates . . . be just and reasonable and not unduly discriminatory or preferential."[201] Any incentive rate boost must be "in fact needed, and . . . no more than is needed, for the purpose."[202] Thus, total ROE, including all incentives, must be no higher than necessary to attract new investment.

Incentives of the magnitude proposed are not needed to encourage transmission development. The Commission has granted vanishingly few project-specific ROE adders since the 2012 Policy Statement, and yet—as the NOPR recognizes—"transmission infrastructure development has remained generally robust at an aggregate level" during that period.[203] The amount of transmission development that has occurred without project-specific ROE adders, along with the strong interest in competitive development, call into question the need for project-based ROE incentives, much less incentives so large as 250 basis points.[204] Such a massive addition to the base ROE (which itself should be sufficient to attract capital) far exceeds the return needed to attract new investment. That failure to balance investor and consumer interests violates the Commission's foundational duty under the FPA.[205]

Second, the size of the proposed cap exacerbates the problems created by the potential for double-counting benefits. If the Commission adopts the proposed ROE

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[201] FPA Sections 219(b)(2) and 219(d).

[202] *City of Detroit*, 230 F.2d at 817. *See also* Order 679-A, PP 21, 24 (incentives are awarded only where they "materially affect" decisions and are "tailored to address the demonstrable risks and challenges").

[203] NOPR P 26. *See also* Part I (documenting the dramatic increases in spending in the past decade).

[204] *See* Part I.

[205] *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("the fixing of 'just and reasonable' rates[] involves a balancing of the investor and the consumer interests."); *see also Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 262 (D.C. Cir. 2007).

incentives, a TO could obtain four ROE adders—the RTO Adder, the Ex-Ante Economic Incentive, the Ex-Post Economic Incentive, *and* the Reliability Incentive—for the same investment without triggering the proposed fixed cap. As a result, a 250-basis-point cap would provide no real limit on the incentives awarded. As discussed in Parts VI.B.7, VI.B.8, and XI.D, the Commission should not allow multiple incentives for the same underlying benefit. But if it allows for multiple additive incentives, the fixed cap should be set at a level that would provide an essential backstop against double-counting.

Third, a cap on incentives provides useful assurance to state and local siting and permitting authorities, their constituents, and ratepayers generally, that the checks they will have to sign to fund new transmission lines are not blank, i.e., will not be entirely untethered from costs. While the Commission may, in individual cases, choose to limit the total package of ROE adders, an explicit outer-bound limit for all cases provides a needed signal to those outside the Commission whose support for transmission development is essential to its realization. The Commission should take to heart the signal that Entergy Corp.-area state regulators sent when they rejected ITC's acquisition of Entergy Corp.'s transmission facilities on the ground that federally-determined transmission rates would be excessive.[206]

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[206] Eileen O'Grady, *Update 1 - Entergy, ITC Call Off Grid Sale, Citing States' Opposition*, Reuters (Dec. 13, 2013), https://www.reuters.com/article/utilities-entergy-itc-idUSL2N0JS0R420131213 ("[S]tate regulators balked at the ITC deal which would have transferred authority to set transmission rates from the state level to the Federal Energy Regulatory Commission (FERC), which allows companies like ITC - the country's largest independent transmission owner - to earn higher rates of return than allowed by states.").

To address these issues, the Commission should lower the fixed cap on incentive ROEs to a more reasonable level: no more than 100 basis points of project-specific adders, plus no more than 50 basis points for RTO participation.[207]

B. In Addition, the Commission Should Retain the Cap on Total ROE at the Top of the Zone of Reasonable Returns

The Commission should not adopt the NOPR's proposal to eliminate the requirement that the total ROE remain within the zone of reasonableness. This check on total ROE remains an essential component of confirming that the resulting rates are just and reasonable, as expressly required by Section 219(d). Both a fixed cap on the adders *and* a zone-of-reasonableness check are needed, as they serve different purposes. The fixed cap prevents any project from getting a disproportionately large share of incentive dollars as discussed in Part VII.A; the top-of-the-range cap further ensures that the resulting rate is still just and reasonable.

The top-of-the-range cap is intended to protect consumers from excessive rates by limiting the total profit a utility is allowed to earn. This requirement is built into the FPA's just and reasonable standard, which allows a reviewing court to "set aside a rate that is outside a zone of reasonableness, bounded on one end by investor interest and the other by the public interest against excessive rates."[208]

The top-of-the-range cap on total ROE is not, on its own, sufficient to ensure just and reasonable rates. The D.C. Circuit, quoting the Commission, has confirmed that "[c]ertain rates, though within the zone, may not be just and reasonable given the

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[207] *See* Part X (discussing why the RTO Adder should not be increased, and limited to ten years or otherwise phased out).

[208] *Pac. Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1116 (D.C. Cir. 2002).

circumstances of the case."[209] As the Commission has recognized, the top of the range of reasonable ROEs produced by the Commission's cost of capital analysis in any particular proceeding could be skewed.[210] But that skew is only upward. If the top proxy company result were—due to data errors or unique circumstances—skewed downwards, that proxy company would not remain at the top of the range because the next highest proxy company would provide the top of the range. Conversely, if the top proxy company were skewed upward, there is no limit (other than the Commission's recently relaxed high-end outlier test)[211] on how a single company could distort the top of the range of reasonable ROEs. That is why the range of reasonableness cap on total ROE should be combined with a fixed cap on project-specific ROE adders.

The NOPR's proposal cannot be supported by concerns that the zone of reasonableness might "preclude utilities with above-average risk profiles from receiving ROE incentives."[212] The NOPR provides no evidence that this problem is likely to occur. It uses the example of "a group of utilities with above average risk,"[213] but ignores the fact that the Commission has never found a group of utilities to be of above-average risk. The nature of transmission investment, with the opportunity for virtually assured cost recovery, plus a Commission-regulated base ROE, through formula rates, all but ensures that the NOPR's hypothetical is not a realistic concern that would support abandoning the

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[209] *Emera Me. v. FERC*, 854 F.3d 9, (D.C. Cir. 2017) (citing *Bangor Hydro-Elec. Co.,* 122 FERC ¶ 61,038, P 11 (2008)).

[210] *See, e.g., S. Cal. Edison Co.*, 131 FERC ¶ 61,020, PP 84-87 (2010), *reh'g denied*, 137 FERC ¶ 61,016 (2011), *aff'd in relevant part sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177 (D.C. Cir. 2013); *Nw. Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 n.11 (2002).

[211] *See Ass'n of Bus. Advocating Tariff Equity Coal. of MISO Transmission Owners,* Op. No. 569-A, 171 FERC ¶ 61,154, P 155 (2020).

[212] NOPR P 79.

[213] *Id.*

long-established precedent confining total returns to the top of the zone of reasonableness.

Because the Commission cannot avoid its obligation to set total rates within a zone of reasonableness, and because relying exclusively on the top of the zone of reasonableness to assure just and reasonable rates is statistically unsound, it should require that: (1) project-specific adders be capped at a fixed amount, *and* (2) total ROEs be capped at the top of the zone of reasonable returns.

C. In Any Case, the Commission Should Retain the Top-of-the-Zone Cap on Previously Granted Incentives

If the Commission abandons the zone-of-reasonableness cap on total ROEs for future incentives, it should not allow removal of that condition as imposed on previously granted ROE incentives. Eliminating such restrictions can have no impact on investment decisions made in the past.[214] TOs built projects knowing that their incentives would be capped at the top of the range of reasonableness, and relaxing that condition now will not induce any future actions. As discussed in Part IV.A, for incentives to be just and reasonable, they must be needed to induce voluntary prospective action. Because retroactively eliminating the condition that incentives be capped at the top of the zone of reasonableness will increase rates, but will not provide any benefit to consumers, it is directly contrary to Section 219.

Furthermore, selecting only one part of the rule (the cap on incentives) for retroactive application, without applying the rest of the rule retroactively, is contrary to reasoned decision-making. If the Commission nevertheless allows utilities to apply for

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[214] *See* Order 679-A, P 61 (rejecting ROE increases for projects already built as not necessary to attract new investment, the purpose of Section 219).

removal of their cap on previously granted incentives, it should make clear that the applicant must also demonstrate that its project would have qualified for the incentive under the new policy (e.g., that the project was in the top 10% of as-built benefit-cost ratios). For the Commission to simply assume that projects previously awarded risks and challenges incentives would merit the same ROE incentives based on benefits would negate the NOPR's stated reasons for reform—to better align incentives to benefits.[215]

VIII. NON-ROE INCENTIVES

TAPS agrees with the NOPR's proposed retention of a case-by-case approach to non-ROE incentives. In particular, we appreciate the proposal to retain this approach for addressing requests for hypothetical capital structures. Use of hypothetical capital structures is essential to public power participation in transmission ownership, and thus to achieving Section 219(b)(1)'s objective of promoting transmission investment "regardless of the ownership."[216]

TAPS also does not object to the NOPR's (P 82) proposed continued application of the preexisting rebuttable presumptions (including the important limitation that allows them to apply only "[t]o the extent the [regional planning process or state approval process] . . . require[s] that a project ensures reliability or reduce[s] the cost of delivered power by reducing congestion"[217]) as a predicate to receiving these non-ROE incentives. NOPR P 82. However, the proposed regulatory language must be corrected so that the rebuttable presumptions—which were designed to assist the Commission in determining

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[215] *See* NOPR P 33. *See generally*, Part I.

[216] *See* TAPS Initial NOI Comments at 102-105.

[217] 18 CFR § 35.35(i)(ii)(2) in the Commission's currently effective regulations; Section 35.35(j)(ii)(3) in the proposed regulations at NOPR P 154.

that the statutory threshold is satisfied, as a first step in the risks and challenges approach to incentives—are clearly limited to the non-ROE incentives, and cannot qualify a project for benefits-based ROE incentives.

But as discussed in Part II.A, TAPS opposes the NOPR's proposed elimination of both the nexus test as a limitation on these incentives, and the requirement that the total package must be tailored to the risks and challenges of the particular project not accounted for in base return ROE. Granting non-ROE incentives without evaluating the justness and reasonableness of the total package of incentives, including ROE incentives, will produce excessive rates. The Commission, for example, has long recognized that the assurance of recovery of prudent abandoned plant costs may warrant a lower ROE.[218] Awarding that and other non-ROE incentives without examining whether the applicant's ROE should be adjusted downward fails to recognize the true value of these non-ROE incentives and violates the FPA directive that rates be just and reasonable.

In addition, TAPS opposes the proposal to allow the Abandoned Plant Incentives (permitting 100%, rather than the 50% cost recovery allowed under the Commission's ratemaking policies) to apply to costs prudently incurred from the date the project is selected in a regional transmission plan for the purpose of cost allocation, in the event the project is abandoned due to causes beyond the applicant's control. In creating an exception from current law, which applies the incentive only to costs prudently incurred *after* the Commission order approving the incentive, the NOPR's proposal violates the fundamental requirement that incentives must be limited to those needed to induce future voluntary action, as emphasized in *San Diego Gas & Electric Co. v. FERC*, 913 F.3d 127

[218] *See S. Cal. Edison Co.*, 112 FERC ¶ 61,014, P 61, *reh'g denied*, 113 FERC ¶ 61,143 (2005).

(D.C. Cir. 2019) ("*SDG&E*").[219] *SDG&E* affirmed Commission application of its abandonment incentive "prospectively[] to investment that had yet to occur," rejecting SDG&E's request to recover from ratepayers 100% of the costs prudently incurred prior to the Commission's decision in the event of a qualifying abandonment.[220] The court found that the limitation aligned with long-standing, court-endorsed Commission policies that incentives must induce prospective behavior.[221] The fact that the "*transmission planner* has made the decision to undertake the project" (NOPR P 84 (emphasis added)) does not permit the Commission to grant incentives that are not needed to induce voluntary prospective behavior by the applicant. If the final rule nevertheless includes this exception, it should not be extended beyond projects selected for regional cost allocation through the Order 1000 planning process.

Finally, while TAPS supports the NOPR's statement (*id*.) that to recover any costs under this incentive, applicant "must continue to demonstrate in a FPA section 205 filing that the transmission projects were abandoned for reasons outside of its control and that the costs incurred were prudent," the Commission should clarify that it did not intend to alter the applicant's current obligation in such filings to also "propose a rate and amortization period to recover its costs in a just and reasonable manner."[222]

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[219] *See also* Parts II.A and IV.A.

[220] *SDG&E*, 913 F.3d at 130.

[221] *Id*. at 138 (quoting the 1992 Policy Statement at 61,599 ("'A reward for past behavior'" after all "'does not induce future efficiency and benefit consumers'")).

[222] *See United Illuminating Co*., 167 FERC ¶ 61,126, P 42, *reh'g denied*, 169 FERC ¶ 61,250 (2019).

IX. INCENTIVES AVAILABLE TO TRANSCOS

TAPS supports the NOPR's proposal to eliminate the Transco-specific incentives currently available under the Commission's incentives policy. The NOPR presents a compelling case, citing extensive evidence presented in the NOI proceeding, relevant precedent, and its own analyses, that the Transco incentives burden consumers with additional costs not warranted by the limited actual benefits of the Transco model.[223]

The NOPR, however, does not include any proposal on the treatment of previously granted Transco adders, instead seeking comments on that question. TAPS strongly urges the Commission to eliminate them. The NOPR's well-supported findings demonstrate that it would be unjust, unreasonable, and unduly discriminatory to continue to burden consumers with rates elevated by previously awarded Transco adders. For example, the conclusion that "we have not seen evidence of Transcos delivering the outcomes that the Commission had expected" (NOPR P 87) draws upon the Commission's own analyses and those provided by TAPS and others showing that Transcos have not exhibited investment levels significantly greater than traditional public utilities, as bolstered by enhanced planning through Order 1000 and the role of RTOs. *Id.* PP 88-89. The NOPR (P 89) confirms the validity of concerns about high Transco rates, noting that ITC Holding subsidiaries have had the highest rates in MISO for a decade.

The NOPR also correctly concludes that the increasing affiliation of Transcos (as documented by the NOPR P 90 & n.105) means that "[s]uch entities do not provide assurance of an absence of conflicts of interest with generation-owning affiliates or of a singular focus on transmission investment and operation" (*id.* P 90). This finding reflects

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[223] *See also* TAPS Initial NOI Comments at 92-96.

the erosion of a key underpinning of Order 679's grant of Transco incentives: "Independence is an important component of the positive contribution of Transcos on investment in needed transmission infrastructure."[224] And the Commission recently reduced to 25 basis points the Transco adder for the ITC Holding affiliates, finding based on a case-specific analysis that the integrity and independence of the ITC Companies' investment planning, capital formation, and investment processes were compromised by their affiliations.[225] As this example highlights, the task of assessing the impact on decision-making of increasingly complex and sprawling corporate structures, with parents or affiliates in markets that are increasingly interrelated, is only getting harder. Elimination of all previously granted adders would appropriately eliminate the Commission's obligation to continue this monitoring in light of the NOPR's well-supported findings that the Transco model has failed to produce superior levels of transmission investment on a sustained basis.

No reliance interest requires burdening consumers and businesses with costs elevated by continued application of adders previously granted to existing Transcos. The Transco adder is not identified in Section 219, and nothing in Order 679 assured Transcos that their adder would be permanent, as the reduction of the ITC Holdings affiliate adders illustrates. The NOPR's listing of previously-granted Transco adders[226] confirms that most of the twelve Transcos currently receiving adders have already enjoyed these excessive returns for a decade or more; only two have held them for less than five years.

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[224] Order 679, P 240.

[225] *Consumers Energy Co. v. Int'l Transmission Co*., 165 FERC ¶ 61,021, P 74 (2018), *reh'g denied,* 168 FERC ¶ 61,035, *petition for review pending sub nom. Int'l Transmission Co. v. FERC*, No. 19-1190 (D.C. Cir. filed Sept. 11, 2019).

[226] NOPR P 90 n.106.

Given these undue profits reaped over long periods of time, any claimed reliance interest cannot trump the Commission's paramount obligation to ensure just and reasonable rates. All existing Transco adders should be terminated based on a generic finding under Section 206 that their continuation is unjust and unreasonable, with such Transcos directed to make a single-issue compliance filing removing the adder.

At minimum, the final rule should immediately eliminate any adder that has been in effect for five years or longer, and terminate any remaining adders on the date they have been in effect for five years. It is inappropriate to protect investors longer than the Commission protects consumers, as illustrated by the five-year period that generally applies to customer hold-harmless protections in the merger context.[227] Any continuation of the Transco adder should also be limited to new facilities, and exclude acquired facilities, which raise costs without delivering any value whatsoever to consumers.

X. INCENTIVES FOR RTO PARTICIPATION

A. The Commission Should Not Double the RTO Adder to 100 Basis Points

To be just and reasonable, an incentive must be set at the level needed to induce the desired conduct, and no higher.[228] Congress has identified the conduct to be induced: *joining* an RTO.[229] Because there is no basis to conclude that doubling the RTO Adder from 50 to 100 basis points is needed to induce TOs to join RTOs, the Commission

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[227] *See, e.g., NSTAR*, 136 FERC ¶ 61,016, P 62 (2011) (approving five-year commitment to hold transmission and wholesale requirements customers harmless from costs related to the merger).

[228] *See* Part II.A.

[229] FPA Section 219(c) (directing the Commission to provide incentives to each utility "that *joins* a Transmission Organization") (emphasis added).

should not adopt this proposal. Rather, the RTO Adder should be retained at a level no higher than the current 50 basis points (with a limited duration as discussed in Part X.C).

The NOPR does not cite a single piece of evidence that doubling the RTO Adder is needed to induce utilities to join (or even remain in) RTOs. The absence of citation is striking, given the hundreds of pages of NOI comments and the enormity of the additional cost burden imposed by the unjustified increase in the RTO Adder.

Moreover, the NOPR ignores the substantial evidence in the NOI proceeding that the 50-basis-point RTO Adder is more than sufficient. Currently, '"two-thirds of the nation's electricity load is served in RTO regions,"'[230] demonstrating the efficacy of the Commission's existing policies. And utilities that have joined RTOs already have strong incentives to remain participants: even where utilities could withdraw from an RTO without state approval,[231] the extensive benefits of RTO participation—which the NOPR highlights[232]—are a powerful inducement to remain in RTOs.

In fact, the NOPR's proposal to increase the RTO Adder could perversely *discourage* utilities from joining RTOs. A state regulator that has authority to approve a utility's application to join an RTO may be less likely to approve the request recognizing the adder-increased costs. Generically establishing the RTO Adder at 100 basis points,

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[230] TAPS Initial NOI Comments at 97 (quoting FERC, *Electric Power Markets: National Overview* (Apr. 10, 2019), https://www.ferc.gov/market-oversight/mkt-electric/overview.asp)

[231] *See CPUC 2018* at 971 (discussing California law requiring California utilities to seek approval from the California Public Utilities Commission to withdraw from the CAISO); *but see Pac. Gas & Elec. Co.*, 168 FERC ¶ 61,038 (2019), *reh'g denied*, 170 FERC ¶ 61,194 (2020), *petition for review filed sub nom. Cal. Pub. Utils. Comm'n v. FERC*, No. 20-71335 (9th Cir. filed May 11, 2020) (disagreeing with the California Commission's interpretation of state law).

[232] NOPR P 97.

without any demonstration—on a case-by-case basis as provided in Order 679[233] or otherwise—that this dramatic increase is needed to induce TOs to join RTOs could well create an unnecessary barrier to RTO expansion, contrary to Congress' intent.

TAPS estimates that the cost to consumers of the proposed 100-basis-point RTO Adder would begin around $800 million a year, and will escalate as transmission ratebase continues to expand.[234] The benefits of RTO participation, even if greater than that amount, cannot justify the proposed dramatic increase in the RTO Adder because doubling the RTO Adder will not increase consumer benefits. Forcing consumers to pay hundreds of millions more each year to get exactly the same benefits is unjust and unreasonable.

Nor can the NOPR's doubling of the RTO Adder be justified as providing compensation for "increased duties and responsibilities associated with RTO/ISO membership."[235] The example provided—the duty to develop regional transmission planning processes—demonstrates the flaw in the NOPR's rationale: all public utility

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[233] Order 679, P 326 (correctly finding that a case-by-case analysis is needed).

[234] TAPS Initial NOI Comments at 97 estimated the cost of the 50 basis point adder to be around $400 million per year) based on Regulatory Research Associates, RRA Topical Special Report, *Electric Transmission: Rate Bases, Rate Base Growth and ROEs: 2018 Update*, 5, tbl.4 (June 4, 2018), https://platform.mi.spglobal.com/InteractiveX/file.aspx?id=393762744&KeyFileFormat=PDF&reqFrom=SNL3 (subscription required), "Transmission rate base growth by region". For the six RTO regions, RRA reports an aggregate 2017 transmission rate base of $98,628,410,000. Multiplying that rate base by a conservative 50% equity capital structure and 50 basis points produces a pre-tax 2017 estimated national total effect of the 50 basis point adder, which on that conservative basis exceeded $245 million. The same RRA table estimates annual growth rates in those six regions' rate bases that average almost 13.5%. (This is a simple average; weighting by the respective regions' rate bases would produce a higher growth rate, exceeding 15%.) Applying the lower, simple average growth rate, we estimate the six RTO regions' aggregate 2019 rate base as $98,628,410,000 x 1.13455 x 1.13455=$126,954,854,524. Multiplying by 1.3 to roughly gross up for federal and state income taxes on the adder, and again using a 50% equity capital structure and 50 basis point adder, produces a with-tax, 2019 estimate of the adder's nationwide annual direct cost to consumers: $412,603,277.

[235] NOPR P 97; *see also id.* P 93 (finding that the "RTO-Participation Incentive also compensates transmitting utilities for the ongoing duties and responsibilities of RTO/ISO membership.").

transmission providers have that duty. Other examples fare no better—the obligation to meet reliability standards and to obey tariff requirements that might change at the Commission's direction are similarly applicable to all public utility TPs/TOs.[236] And TOs clearly do not view the "obligation to build new transmission facilities at the direction of the RTO"[237] as an increased burden, as demonstrated by the fact that they have strongly opposed policies that would deprive them of the right to build those projects instead of non-incumbent developers.[238] To the extent that there are unique duties and responsibilities associated with RTO membership, TOs are already entitled to compensation for the prudently incurred costs of fulfilling those responsibilities through Section 205, not Section 219.

The NOPR's explanation that the RTO Adder recognizes not only the benefits, but also the "risks[] and associated obligations," of RTO membership is ironic, given the NOPR's rejection of the risks and challenges approach,[239] and its proposal to grant Economic, Reliability, and Technology Incentives for projects that pose no risks not already fully compensated by the TO's base ROE. Given the absence of any demonstrated need for any increase in the current RTO Adder to induce TOs to join RTOs, much less the 100% increase proposed, and the potential that this dramatic increase could well be counter-productive to Congress' objective in enacting

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[236] NOPR P 96.

[237] *Id.*

[238] *See Xcel Energy Serv., Inc. v. Am. Transmission Co., LLC*, 140 FERC ¶ 61,058 (2012) (granting complaint challenging ATC's claim to construction and ownership rights associated with the 145-mile, 345 kV LaCrosse-Madison Line to be constructed within the MISO footprint). The Commission was called upon to address similar disputes in *Am. Transmission Co., LLC v. Midwest Indep. Sys. Operator, Inc.*, 142 FERC ¶ 61,090 (2013) and *ITC Midwest, LLC v. Am. Transmission Co., LLC*, 142 FERC ¶ 61,096 (2013).

[239] NOPR PP 3, 97.

Section 219(c), the Commission should not double the RTO Adder. It should be limited to no more than 50 basis points and, as discussed in Part X.C, restricted in duration.

B. The Commission Should Retain the Requirement that the RTO Adder Is Only Available When Participation Is Voluntary.

As discussed in Part IV.A, an incentive can be just and reasonable only if it prospectively induces voluntary conduct. That is especially true of the RTO Adder. The Court of Appeals has specifically found that the Commission's "longstanding policy [is] that incentives should only be awarded to induce voluntary conduct," and that the Commission must inquire whether its 50 basis point incentive adder "could induce [a utility] to remain in [an RTO]."[240] The NOPR's proposal to grant utilities a 100-basis-point RTO Adder regardless of whether their remaining in an RTO is voluntary, upends that policy and is unjust and unreasonable.

Contrary to the NOPR's suggestion,[241] Section 219 *does* impose a voluntariness condition on granting the RTO Adder. By enacting Section 219(d), which expressly makes all Section 219 incentives subject to the just and reasonable requirements of Sections 205 and 206, Congress called into play the precedent developed over decades that established the contours of just and reasonable incentives. The Commission's long-standing policy that just and reasonable incentives must induce voluntary prospective conduct, a requirement the courts have characterized as an "obvious proposition,"[242] cannot be ignored. The NOPR's proposal to eliminate the voluntariness requirement for the RTO Adder is contrary to the unambiguous meaning of the statutory term "incentive,"

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[240] *CPUC 2018* at 978, 979.

[241] NOPR P 98 ("FPA section 219 obligates the Commission to provide an incentive to each transmitting utility or electric utility that joins a Transmission Organization, independent of the obligation to do so.").

[242] *Me. Pub. Utils. Comm'n v. FERC,* 454 F.3d 278, 289 (D.C. Cir. 2006).

contrary to the statute's requirement for just and reasonable rates, and contrary to common sense. The voluntariness of a utility's membership in an RTO is "*logically relevant* to whether it is eligible for an adder."[243]

The NOPR's concern that retaining the voluntariness requirement might result in "an uneven playing field" is misplaced.[244] First, "the potential to distort investment decisions within interstate corporate families and within multistate RTOs"[245] is mitigated by the fact that, within an RTO, transmission planning occurs through an open and transparent stakeholder process, and that an RTO's decisions about which projects are needed should be based on engineering studies, not the amount of a particular TO's incentive. Second, the NOPR's solution to the potential distortion—eliminating the voluntariness requirement—will not fully address the concern, because of state policies and myriad other influences on interstate corporate families (which may include subsidiaries inside and outside RTOs). To the extent the difference in voluntariness, and therefore availability of the RTO Adder, is due to the laws or actions of a particular state, or the TO's prior actions or agreements (e.g., merger conditions), any such difference is not undue. In any event, a level playing field concern provides no excuse for eliminating a central tenet of what is required for just and reasonable incentives.

C. The Commission Should Put a 10-Year Limit on the RTO Adder

RTO Adders should also be limited in duration. A TO eligible for the RTO Adder should be permitted to collect it for no more than ten years, inclusive of any years when

[243] *CPUC 2018* at 978, 974-5 (emphasis added).

[244] NOPR P 98.

[245] *Id.*

that TO participated in a different RTO, or when a predecessor owner of the recipient's transmission system participated in an RTO.

Section 219(c) narrowly authorizes an incentive for *joining* an RTO. Although the Commission in Order 679-A (P 86) provided that the RTO Adder would be "effective for the entire duration of a utility's membership in the [RTO]," rewarding participants for not withdrawing from RTOs has become less justified with the passage of time, as TOs have become well-rooted. As RTO services have grown, so too have other inducements for TOs to remain in an RTO. The increased RTO benefits to which the NOPR points—including access to competitive markets, optimization of the transmission system, and reserve sharing[246]—are enjoyed not just by consumers, but by TOs themselves. For example, a TO may want to ensure its generation function continued access to RTO markets (with the TO's authority to make market-based sales generally evaluated on an RTO-wide basis).[247] The Commission has recently enhanced that advantage by eliminating the need for those in RTOs to submit market power screens in many cases.[248]

As described in Part X.A, the cost burden associated with the RTO Adder (particularly if doubled) is enormous, amplifying the already heavy burden of rising

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[246] NOPR P 94.

[247] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295*,* PP 231, 235, *clarified*, 121 FERC ¶ 61,260 (2007), *on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *on reh'g and clarification*, Order No. 697-C, 127 FERC ¶ 61,284, *corrected*, 128 FERC ¶ 61,014 (2009), *clarified*, Order No. 697-D, 130 FERC ¶ 61,206, *clarified*, 131 FERC ¶ 61,021 (2010), *reh'g denied*, 134 FERC ¶ 61,046 (2011), *reh'g denied*, 143 FERC ¶ 61,126 (2013), *review denied sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 567 U.S. 934 (2012). Outside RTOs, market power screens focus on the seller's balancing authority area and first tier balancing authority areas (*id.* P 232), a test that can be challenging for vertically integrated utility.

[248]*See Refinements to Horizontal Mkt. Power Analysis for Sellers in Certain Reg'l Transmission Orgs. & Indep. Sys. Operator Mkts.*, Order No. 861, 168 FERC ¶ 61,040 (2019), *reh'g denied*, Order No. 861-A, 170 FERC ¶ 61,106 (2020).

transmission costs. In light of the additional inducements to continued RTO membership, it is unreasonable to saddle customers in perpetuity with an unnecessary RTO Adder.

Restricting collection of the adder to no more than ten years from the date the TO (or its predecessor) initially joined an RTO strikes the appropriate balance between incentivizing TOs to join RTOs and ensuring incentives are not unduly burdensome.[249] Ten years is sufficient for a TO to fully integrate into an RTO and participate in several planning cycles, and is on par with the Commission's initial thinking regarding RTO Adders.[250] A time-limited adder is consistent with Section 219(c)'s mandate to provide an incentive *for joining* an RTO; it does not require an incentive *for remaining* in an RTO. If Congress had intended the incentive be permanent, it would have so required.

XI. INCENTIVES FOR TECHNOLOGY

TAPS strongly supports the NOPR's rejection of calls to implement shared-savings incentives for transmission technologies. As TAPS explained in Post-Workshop comments in *Grid Enhancing Technologies*, Docket No. AD19-19, shared-savings incentives are not just and reasonable; grant an internal rate of return for projects unrelated to—and far in excess of—the level needed to attract the needed investment; and make low-cost, low-risk technology expensive for consumers.[251] At the GETs Workshop, RTOs and IMMs—the entities most familiar with adjusted production cost calculations and state-of-the-art modeling—also broadly agreed that benefit calculations, even when

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[249] While TAPS suggests ten-year limitation, we are open to other mechanisms to reduce duration, level, and/or scope of the RTO Adder.

[250] *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032, PP 2, 28 (2003) (calling for a 50 basis point incentive for RTO participation that would be discontinued December 31, 2012).

[251] TAPS GET Post-Workshop Comments at 11-15. *See also* Leovy Statement at 10-13.

performed by an independent transmission provider, are useful for *comparing* among competing projects, but inadequate and too unreliable for *setting* a shared-savings rate.[252] Consistent with that limitation (although the NOPR does not explain its underlying reasoning), the NOPR appropriately does not propose any shared-savings incentives.

The financial incentives the NOPR does propose for "technologies that, as deployed in certain circumstances, enhance reliability, efficiency, capacity, and improve the operation of new or existing transmission facilities" (NOPR P 101), however, are also flawed. They are not tailored to address the actual obstacles to the development and deployment of advanced transmission technologies. As a result, the NOPR's proposal is unlikely to foster such technologies; instead, it appears to allow large financial rewards to technology late-adopters that have failed to keep up with good utility practice.

A. The NOPR's Incentives for Deployment of Transmission Technologies Are Improper

1. The NOPR's Technology Incentives fail to address the real obstacles to deploying new technologies.

"[T]o encourage the deployment of innovative and cost-effective technologies" (P 107), the NOPR proposes two financial incentives ear-marked exclusively for the deployment of transmission technologies (together, "Technology Incentives"):[253]

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[252] TAPS GETs Post-Workshop Comments at 12-13. According to Workshop panelists, estimating the future benefits of grid-enhancing technologies is enormously complicated. Benefit projections rely on assumptions about the evolving grid and changes in generation and load—all of which are open to challenge. And benefit projections become increasingly speculative the further they are into the future. *See*, *e.g.*, GETs Tr. Day 2, 312:7-9 (Patton, Potomac Economics) ("The idea that you could calculate benefits that are even close to accurate, especially when you go out in time, it's just not realistic."). Once any new transmission facility goes into service, the grid topology changes; plants entering and exiting service can dramatically affect adjusted production cost savings estimates. Because there are so many moving parts, it may be impossible to isolate the impact, benefits, or savings from a particular facility or technology. *See also* Part V.B.

[253] As discussed in Part XI.D, problematically, the NOPR also invites double-counting by making transmission projects eligible for incentives based on the use of technology, while apparently also allowing

1. Transmission Technology Incentive. A 100-basis-point ROE incentive on the cost of the specified transmission technology project (including any amounts awarded regulatory-asset treatment), deployed on either a new or existing transmission facility. *Id.* PP 105-107;

2. Deployment Incentive. Regulatory-asset treatment for the initial two years of expenses related to deploying and operating that technology (starting with procurement), with amortization over five years. *Id.* PP 108-110.

Both incentives raise basic concerns. As discussed in Part II.A, the Transmission Technology Incentive's 100-basis-point adder is improper because there has been no demonstration that it is needed to induce investment in transmission technologies. The Deployment Incentive's authorization to capitalize expenses is also inappropriate. It violates the principles underlying cost-based ratemaking; and it only makes sense as a financial "incentive" if the Commission assumes that the base ROEs it grants to TOs are significantly in excess of the utility's actual cost of attracting and carrying capital.

More fundamentally, although the NOPR (P 100) points out that "there is currently no standalone incentive for advanced technology" and that experience "suggests that this approach has not been effective in encouraging deployment of … [technology] improvements [to existing facilities]," the proposed incentives fail to address the real obstacles to deployment of new transmission technologies. What was most striking about the November 2019 Workshop on GETs was how few panelists pointed to the lack of incentives as the obstacle to deployment, or thought that benefits-based incentives made sense. Incentives were barely mentioned during the first day of the Workshop, in which panelists were asked to address "current deployments of grid-enhancing technologies,

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that technology to contribute toward a project's eligibility for Economic Incentives.

and what actions the Commission could take to help alleviate any operational challenges or concerns" and "what challenges exist in current transmission planning processes."[254]

Instead, despite some characterizations of the various technologies discussed as "mature,"[255] numerous panelists stressed the need for those technologies to be "proven" before deployment could be seriously considered.[256] It would be imprudent for the Commission to assume that shiny new transmission technologies are plug-and-play. Workshop panelists indicated that some GETs are not yet ready for prime time; and they described experience with new technologies, which has involved a lengthy process of working with vendors through multiple iterations of the technology, just to get to the point of really assessing its potential positive and negative impacts.[257] Based on the Workshop, the need to better understand the upsides and downsides of new GETs, so there is comfort that they will achieve their advertised results without adverse impacts, is a prerequisite—and the most significant obstacle—to their deployment.

Panelists also pointed to obstacles created by vendors who seek to protect what they view as proprietary information. Some found that the "black box" provided by

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[254] Final Agenda for the November 5-6 Workshop 1-2, *Grid Enhancing Technologies*, Docket No. AD19-19-000 (Nov. 12, 2019), eLibrary No. 20191112-4000.

[255] *See*, *e.g.*, Notice Inviting Post-Workshop Comments, Post-Workshop Questions for Comment 1, *Grid Enhancing Technologies*, Docket No. AD19-19 (Jan. 17, 2020), eLibrary No. 20200117-3021.

[256] GETs Tr. Day 2, 266:11-24, 267:3-7 (Bradish, AEP); Grid-Enhancing Technologies Workshop Transcript Day 1, 152:18-153:11 (Webb, MISO), *Grid Enhancing Technologies*, Docket No. AD19-19-000 (Jan. 6, 2020), eLibrary 20200106-4004 ("GETS Tr. Day 1"), *id.* 76:1-5 (Bradish, AEP, "[W]e've deployed just about every grid-enhancing technology that's come our way that's been proven."), *id*. 77:25-78:2 (Bradish, AEP, "Piloting new technology with unproven performance is a challenge."), *id.* 125:9-15 (Webb, MISO).

[257] GETs Tr. Day 1, 90:4-17 (Bradish, AEP); *id.* 100:10-15 (Dagle, PNNL).

vendors insufficient to permit the modeling required to fully understand and assess the impacts of deploying those new technologies.[258]

And some panelists stressed that evaluation of a new technology requires looking ahead toward broader deployment across the grid, due to interactions both between devices of the same type and with other new technologies that may be implemented. Piecemeal assessment of individual projects is insufficient and could be problematic. For example, Dr. Anjan Bose (Washington State University) described how more widespread adoption of a single technology or the implementation of multiple technologies could cause grid devices to "fight each other."[259] AEP witness Bradish said this type of conflict is happening today even without widespread adoption, and "it gets harder to operate the grid with more [GETs] on it."[260]

These types of conflicts seem likely to be a particular problem in the United States where the integrated AC grid is made up of parts owned and maintained by many different entities, and devices from multiple vendors are likely to be deployed simultaneously in varied configurations and conditions. In this context, it will be crucial to assure consistent and secure communications among devices, as well as careful vetting of automatic systems to avoid unintended consequences. This will be especially challenging in non-RTO areas where TO systems are in close proximity, but there is no regional transmission provider to evaluate potential interactions with other systems.

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[258] GETs Tr. Day 1, 92:21–93:17 (Bradish, AEP); *id.* 170:13–171:2, 191:15-25 (Enayati, National Grid); *id.* 125:9-15 (Webb, MISO); *id.* 94:20-24 (Bose, WSU).

[259] *Id.* 80:6-12, 114:17–115:3 (Bose, WSU).

[260] *Id.* 90:18-23 (Bradish, AEP).

The failure to adequately understand and anticipate such consequences can have direct, adverse effects on electric service. For example, although in a different subsector of the industry, experience with widespread deployment revealed a lack of clear understanding of what inverter-based resource technology is capable of and how the controls respond to various system conditions, causing unreliable operations.[261]

If the Commission wants to advance the deployment of new transmission technologies, it should focus on the technological-maturity obstacles identified at the GETs Workshop and take appropriate steps to overcome them, rather than looking toward financial incentives that will not address the real challenges, and will make new technologies—which their proponents claim are low-cost and low-risk—expensive for consumers. Rate incentives are the wrong tool for the job; and granting them in this context is inconsistent with the FPA requirement, expressly made applicable to incentives

[261] *See 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC (June 2017), https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf; *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC (Feb. 2018) https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf. These major events resulted in NERC Alerts, one in 2017, *Industry Recommendation*, NERC (June 20, 2017), https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf, and one in 2018, *Industry Recommendation*, NERC (May 1, 2018), https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf. Evaluation of the impact of increasing deployment of inverter-based resources, and guidelines for actions that should be taken to mitigate adverse impacts on the bulk power system has continued. *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*, NERC (Sept. 2019), https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf.

by Section 219(d), that to be just and reasonable, incentives must be "in fact needed, and no more than is needed, for the purpose."[262]

2. To effectively foster the deployment of advanced technologies, they should be integrated into existing transmission planning processes.

Given the actual challenges faced by new transmission technologies, Commission leadership in identifying and publicizing best practices for, and successful deployments of, new technologies is the most effective way to encourage their development and adoption. As TAPS has previously commented, broad sharing of pilot and deployment results is essential to build knowledge, support confidence in new technologies, and encourage their adoption.[263] As part of that effort, Commission-led forums like the Managing Line Ratings Technical Conference held last year could provide a valuable national stage for emerging technologies and host frank, industry-wide discussion of the state-of-the-art and areas of additional research needed before broader deployment. Commission statements that a new technology is now considered Good Utility Practice under the Commission's tariffs,[264] or directives requiring TPs to report on whether and why that technology has not been deployed in their footprints, would also go a long way toward fostering widespread adoption.

Once new technologies have been adequately tested and are "ready for prime time," they should be integrated into existing Order 890 and Order 1000 planning

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[262] *City of Detroit v. FPC*, 230 F.2d at 817. *Accord Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d at 1503. *See also* Order No. 679-A, PP 25, 27 (incentives are awarded only where they "materially affect" decisions and are "tailored to address the demonstrable risks or challenges").

[263] TAPS GET Post-Workshop Comments at 17-18.

[264] *C.f. Policy Statement on Matters Related to Bulk Power System Reliability,* 110 FERC ¶ 61,096, P 7 (2005) ("interpret[ing] the term Good Utility Practice as used in the OATT to include compliance with [the then not-yet-mandatory] NERC's Version 0 Reliability Standards").

processes, so that they can compete with other transmission and non-transmission alternatives (including other new technologies). For example, an RTO could identify an area of the system which might benefit from a new technology and solicit competitive proposals. Any ROE and other cost-increasing incentives that the developer plans to seek would be disclosed in each proposal, so that their costs can be considered in determining which project is selected by the RTO. To be effective, such processes should enable competition between technologies, and by technology project developers beyond just the incumbent TO of the facilities to which the transmission technology would be connected.

A robust and transparent review of transmission technology deployments by regions and stakeholders is also needed, given the possibility that unintended consequences and conflicts between incompatible new technologies will emerge. In RTO regions, RTOs must have the means and opportunity to assess the value and risks of installing a new technology. They will particularly need to evaluate effects on RTO operators and how technologies will interact with each other with expanded deployment; and they must develop procedures for resolving any conflicts that emerge in a nondiscriminatory manner. Integrating new technology deployments with existing RTO processes will also allow RTOs to detect and guard against discriminatory applications of new technologies that advantage the TO's generation and disadvantage others.

In non-RTO areas, new technologies should likewise be vetted through an Order 1000 regional planning process. Regions should be required to integrate consideration of advanced technology projects into their processes for selecting projects for regional cost allocation. Given the potential for adverse interactions among technologies that may impact adjacent and overlapping TO systems, a TO deploying new technologies should be required to coordinate with others in their region to identify and resolve any conflicts or unintended consequences for areas beyond the TO's own footprint.

B. The NOPR's Definition of "Eligible Transmission Technologies" Is Too Broad; If Retained, the Technology Incentives Should Be Tailored to New Cutting-Edge Technologies

Although the claimed purpose of the NOPR's proposed Technology Incentives is to "encourage the deployment of innovative and cost-effective technologies" (NOPR P 107), its proposed definition of "eligible transmission technologies" casts far too wide a net and fails to exclude routine investments that have long been viewed as baseline good utility practice and should be ineligible for the NOPR's deployment incentives. Specifically, the NOPR would authorize incentives, based on a "case-by-case" evaluation (*id.* P 102), for technologies "that, as deployed in certain circumstances, enhance reliability, economic efficiency, capacity, and improve the operation of new or existing transmission facilities" (*id.* P 101). The only exclusion from this all-encompassing definition is that "transmission system assets traditionally associated with the transportation of electric power, such as power lines, power poles, capacitors, and other substation equipment" will "generally" not be considered "eligible transmission technologies." *Id.*

The breadth of the NOPR's "eligible transmission technologies" definition is not only inconsistent with its stated objective, but it is also an unexplained and inexplicable departure from Order 679 and the 2012 Policy Statement—both of which interpreted FPA Section 219 in conjunction with Section 1223 of Energy Policy Act 2005 to conclude that the statute is a Congressional directive "to encourage the deployment of *advanced* transmission technologies that increase the capacity, efficiency[,] and reliability of an existing or new transmission facility."[265] The NOPR does not recognize, let alone explain, this significant departure from a prior policy.[266]

The NOPR's "eligible transmission technologies" definition is so open-ended that it is unworkable. It gives the Commission broad discretion to award a 100-basis-point ROE adder and the right to capitalize current account expenses to virtually anything. Generic findings on the reasonableness of such an amorphous proposal cannot be made or defended. The NOPR does not, and cannot, justify the need for the 100-basis-point ROE adder or capitalization incentive for transmission technology as a generic matter. Because it expressly declines to specify any meaningful parameters for assessing *which* technologies would receive the proposed Technology Incentives (NOPR P 102), it is impossible to "comment on whether [the proposed incentive] is proportional to the benefits offered to consumers by eligible transmission technologies and if this incentive is sufficient to attract investment in such transmission technologies," as the NOPR requests. *Id.* P 107. The NOPR's failure to set any ground rules on which technologies might be entitled to the Technology Incentives means that the appropriateness of the incentive mechanisms and magnitudes themselves must be litigated in each case, based on specific facts, along with the benefit-cost evaluation submitted by the applicant. This is the opposite of the increased certainty the NOPR (P 33) says its reforms are intended to provide.

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[265] Order 679, P 41 (emphasis added); *see also id.* PP 280, 289 (seeking to promote "innovative technologies" for new transmission facilities, and stating that if "applicants seek additional incentives for advanced technologies, the Commission will consider the propriety of such incentives on a case-by-case basis"); 2012 Policy Statement P 23.

[266] *See*, *e.g.*, *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. at 2125-27 (agency departures from prior policy, especially policy applied in adjudications, must be explained).

If the Commission does not completely eliminate the NOPR's Technology Incentives, they should be narrowly targeted at innovative, advanced technologies. TOs should not receive above-cost returns for maintaining their systems consistent with good utility practice. As TAPS panelist Steve Leovy explained at the GETs Workshop:[267]

> Utilities didn't need special incentives to get rid of copper conductors and start installing aluminum conductors . . .Technology changes, and expectations and best practices should change along with [technology].

Mr. Leovy warned that "[p]utting incentives into this mix risks rewarding late adopters."[268] The plain language of the NOPR's Technology Incentives would allow just that. Decades-old technologies like Supervisory Control and Data Acquisition ("SCADA") systems would fall within the NOPR's definition of "eligible transmission technologies" that can receive the proposed Technology Incentives. So would Ambient Adjusted Ratings ("AARs") systems, which have long been deployed in large areas and are now being adopted by many utilities across the country without incentives.[269]

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[267] GETs Tr. Day 2, 242:21–243:2 (Leovy).

[268] *Id.* 243:3-4.

[269] *Id.* 242:17-19 (Leovy) ("AARs, at this point, should be becoming regarded as standard best practice"); GETs Tr. Day 1, 76:17-24 (Bradish, AEP) (noting AEP's use of AARs for many years); Managing Transmission Line Ratings Conference Transcript Day 1, 97:9-17 (Murphy, PJM), *Managing Transmission Line Ratings*, Docket No. AD19-15-000 (Oct 8, 2019), eLibrary No. 20191008-4001 ("MTLR Tr. Day 1") ("Technologically, PJM has implemented ambient adjusted ratings . . . . We use that with the majority of our transmission owners."). At the *Managing Transmission Line Ratings* technical conference, both Monitoring Analytics and Potomac Economics agreed that TOs should be required to implement AARs, rather than granted rate incentives for doing so. Managing Transmission Line Ratings Conference Transcript Day 2, 308:2-8 (Bowring, Monitoring Analytics), *Managing Transmission Line Ratings*, Docket No. AD19-15-000 (Oct 8, 2019), eLibrary No. 20191008-4002, *id.* 308:19-21 (Chiasson, Potomac Economics); FERC Technical Conference on Managing Line Ratings: AD19-15, Presentation at 2 (Wander, Potomac Economics), *Managing Transmission Line Ratings*, Docket No. AD19-15-000 (Sept. 10, 2019), eLibrary No. 20190917-4022. *See also* MTLR Tr. Day 1, 143:9-13 (Casablanca, AEP) (recommending "that the FERC issue an order with an appropriate timetable, requiring transmission owners and operators in all regions to implement ambient adjusted ratings on most, if not all, of their Transmission facilities.").

There is no need—and it would be improper—to award incentives for deploying SCADA systems, AARs, and other baseline technologies that are required by good utility practice, and that TOs already have an obligation to install under the OATT.[270] Granting incentives for deploying such standard technologies conflicts with the requirement that to be just and reasonable, incentives should be limited to exemplary, voluntary investment, and exclude those are mandatory.[271] To avoid such outcomes—as well as a flood of incentive applications for routine maintenance and baseline technology—the Commission should dramatically narrow the definition of "eligible transmission technologies."

C. The NOPR's Proposal to Apply a Benefit-Cost Threshold to the Technology Incentives Should Be Clarified and Modified

The NOPR proposes to limit the Technology Incentives to projects that also meet the "ROE incentive benefit-to-cost threshold proposed in this NOPR." NOPR P 103. While TAPS supports the NOPR's intent to require that technology projects demonstrate clear consumer benefits, its proposal is ambiguous and may well be inappropriate. First, the NOPR proposes two different benefit-cost threshold tests—one *ex ante* (75th percentile threshold) and one *ex post* (90th percentile) for economic benefits. The NOPR does not indicate which would apply to the Technology Incentives. In Part V, TAPS urges modifications to the NOPR's Economic Incentives to: (1) increase the benefit-cost thresholds to at least the 90th percentile; and (2) either eliminate the *ex ante* incentive or, at minimum, require an *ex post* confirmation that the benefit-cost ratio upon which the

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[270] TAPS Initial NOI Comments at 34-37. *See also* GETs Tr. Day 2, 321:25 (Patton, Potomac Economics) (because "AARs should be the baseline," any shared-savings incentive for Dynamic Line Ratings should be based on only the incremental benefit realized from DLR, above and beyond the benefits that could be achieved from AARs).

[271] *See, e.g., New England Power Pool*, 97 FERC ¶ 61,093, at 61,477 (2001) (incentive denied to avoid "unjustly reward[ing] NEP for doing what it is supposed to do, i.e., to adequately maintain its facilities in a prudent, cost-effective manner."), and other precedent discussed in Part IV.A.

ex ante incentive was granted has been maintained. Those changes, as well as other safeguards recommended in Part V, should also be applied here.

Second, there is no record evidence to support the NOPR's proposal to use a benefit-cost threshold developed based on a sample of *transmission* projects in RTOs, to evaluate technologies that are expressly defined to *exclude* "transmission system assets traditionally associated with the transportation of electric power." *Id.* P 101. As discussed in Part V, predicting and measuring adjusted production cost savings present significant challenges. To avoid applying an irrelevant standard to transmission technology projects and ensure that only technologies delivering cost-effective exemplary benefits receive the incentive, the Commission should develop a separate benefit-cost threshold tailored to transmission technology projects, similar to the NOPR's proposal to develop separate benefit-cost thresholds for projects above and below $25 million.

D. Technology Benefits Should Not Be Double-Counted

The Commission should clarify that technology benefits cannot be double-counted to justify awarding multiple types of ROE incentives for the same technology investment. Transmission developers, for example, should not be eligible to receive both the technology *and* economic-benefit ROE incentives for the same investment. If the benefits of a transmission technology are included in the adjusted production cost savings analysis used to justify an economic-benefit-based ROE adder, then that technology investment should be ineligible to also receive the NOPR's separate technology ROE adder. Similarly, if a reliability ROE incentive has been granted to a project based on its use of "network management technologies, such as dynamic line ratings, power flows controls, or transmission topology optimization" (*id.* P 72), then the costs of those technologies should *not* be eligible for the NOPR's separate technology ROE adder.

The purpose of deploying new transmission technologies is to provide benefits to consumers, including reliability benefits and adjusted production cost savings. The NOPR specifically requires that transmission technology projects satisfy its economic-benefit test as a precondition for receiving incentives. Allowing transmission developers that are already receiving a Technology Incentive to also receive Reliability or Economic Incentives for the same technology investment is the type of double-count that the NOPR properly seeks to avoid (*id.* P 55). Any final rule should expressly disallow it.

E. Pilot Programs

In addition to the measures described in Part XI.A.2 to showcase and assess emerging technologies, the Commission should consider leveraging existing Order 1000 regions to help coordinate pilot program efforts. In RTOs, TOs contemplating a pilot program should be required to consult with their RTO, which could be given a role in evaluating and selecting pilots in a transparent manner. In non-RTO areas, the Commission should require vetting of pilot programs through the Order 1000 regional planning process. Using these existing regional processes would elevate industry awareness and facilitate coordination and setting of priorities, as well as enhance the opportunity to prevent and mitigate unintended consequences.

The NOPR's rebuttable presumption that pilot programs will be eligible for Technology Incentives (NOPR P 112), however, should be eliminated. The benefits of technology pilot programs are widely spread—far beyond the footprint of the individual utility where the pilot is located. A national grant program, like the ones administered by the U.S. Department of Energy ("DOE"), is the fairest way to support them; and TAPS urges the Commission to coordinate with DOE regarding its efforts to promote new transmission technologies that have the potential to significantly benefit consumers.

In the absence of federal grants, it may well be that the only realistic source of funding for pilot programs is the rates of the individual TOs where the pilots are located. Applying the NOPR's above-cost subsidies to pilot projects, however, will exacerbate the mismatch between the broad benefits of pilot projects and their locally funded costs. And the use of financial incentives in this context is particularly inappropriate because neither the NOPR nor the records of the NOI, Managing Line Ratings, or Grid-Enhancing Technologies proceedings demonstrate that incentives are needed to encourage pilot projects which are already virtually guaranteed full cost recovery. At minimum, if the Commission does not entirely eliminate the NOPR's Technology Incentives for pilot projects, it should reject any proposals to relax the NOPR's proposed size, duration, and eligibility limitations on those incentives.

F. Annual Reporting Requirement

As discussed above, TAPS opposes the NOPR's proposed Technology Incentives. However, should the Commission nevertheless adopt them, the NOPR's annual reporting requirement should be retained and refined. Specifically, the NOPR would require all public utilities receiving a Technology Incentive to submit, "for three years after the incentive is granted," annual filings that "detail[] the progress of the technology, obstacles to its deployment and efforts to overcome them, lessons learned, and any quantifiable data measuring the benefits of the transmission technology project." *Id*. P 113. While the three-year duration is a good minimum length, the duration should be tailored to assure the annual informational filings are useful and serve their intended purpose.

Pilot programs, for example, have a maximum duration of two years from installation to completion. *Id*. P 112. Depending on the amount of time necessary to install the pilot, the NOPR's proposed three-year informational filing requirement could expire before final conclusions have been reached on the performance of the new technology, or even before completion of the pilot. In the case of non-pilot technology projects, it may well take more than three years to fully deploy the technology that is receiving the incentive, let alone meaningfully evaluate the performance of that technology.

The NOPR's annual reporting requirement should thus be extended to encompass the period needed to evaluate the technology that is being subsidized by the proposed incentives. Because one size may not fit all, Technology Incentive applicants should be required to include in the Transmission Technology Statement that accompanies their application (*id*. P 111), a plan and timeline for evaluating the technology to be deployed. In its case-specific order approving the incentive, the Commission should specify the duration of no less than three years for the annual reporting requirement based on that submission, reserving the authority to extend the requirement if there are delays in the installation or completion of the project.

XII. DISCLOSURE OF ANTICIPATED INCENTIVES

In response to the NOPR's request for comment (*id*. P 114), a public utility seeking incentives must be required to disclose all reasonably anticipated incentives to transmission planning regions as part of the public utility's transmission project proposal.

As discussed above (Parts IV.E. and V.D), failure to disclose such costs is a bait-and-switch and would fundamentally undermine Order 1000 planning processes, particularly the competitive transmission development processes now starting to bear fruit.

XIII. PROGRAM MANAGEMENT

TAPS supports the proposed expansion of the Form 730 reporting requirement, and, to the extent that any final rule adopts the NOPR's proposed benefit-based incentives approach, the requirement that public utilities report the estimated annual economic benefits of each transmission project that is under construction that receives any transmission incentive.

TAPS questions the NOPR's proposal to limit the reporting requirement for "actual annual economic benefits" to "five years after the date of completion of the transmission project." *Id*. P 125. This restriction is inappropriate because: (1) the NOPR's proposed ROE incentives for economic benefits are collected for the full life of the project; and (2) the economic-benefit analysis used by the applicant to justify receiving the incentive may well have been based on claimed benefits farther in the future.

The failure of proposed Form 730 to include any metric to evaluate or verify "above and beyond" reliability benefits from projects receiving Reliability Incentives is also troubling. It signals a deeper problem with the NOPR's Reliability Incentives proposal, which TAPS strongly opposes.

CONCLUSION

For the reasons discussed above, the Commission should *not* move forward to a final rule based on the NOPR; but if it does, it should adopt TAPS' recommendations to better align the NOPR's proposals to the Commission's obligations.

Respectfully submitted,

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