UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Electric Transmission Incentives Policy	))	Docket No. PL19-3-000

JOINT INITIAL COMMENTS OF THE ALUMINUM ASSOCIATION, THE AMERICAN CHEMISTRY COUNCIL, THE AMERICAN FOREST AND PAPER ASSOCIATION, THE AMERICAN PUBLIC POWER ASSOCIATION, BLUE RIDGE POWER AGENCY, THE CALIFORNIA MUNICIPAL UTILITIES ASSOCIATION, THE CALIFORNIA PUBLIC UTILITIES COMMISSION, THE CITIES OF ANAHEIM, AZUSA, BANNING, COLTON, PASADENA, AND RIVERSIDE, CALIFORNIA, THE ELECTRICITY CONSUMERS RESOURCE COUNCIL, THE INDUSTRIAL ENERGY CONSUMERS OF AMERICA, MARYLAND OFFICE OF PEOPLE'S COUNSEL, THE MODESTO IRRIGATION DISTRICT, THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES, THE NEW YORK PUBLIC SERVICE COMMISSION, NORTHERN CALIFORNIA POWER AGENCY, THE OFFICE OF THE PEOPLE'S COUNSEL FOR THE DISTRICT OF COLUMBIA, THE PUBLIC UTILITY LAW PROJECT OF NEW YORK, THE TRANSMISSION AGENCY OF NORTHERN CALIFORNIA, AND THE VIRGINIA OFFICE OF THE ATTORNEY GENERAL DIVISION OF CONSUMER COUNSEL

June 26, 2019

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INITIAL COMMENTS OF
THE JOINT COMMENTERS

In its March 21, 2019 Notice of Inquiry ("Incentive NOI" or "NOI"),[1] the Federal Energy Regulatory Commission ("Commission" or "FERC") initiates a broad examination of its electric transmission incentive policies under section 219 of the Federal Power Act ("FPA").[2] The 105 individually-numbered questions in the NOI solicit input on virtually every aspect of the Commission's transmission incentive rules and policies, as well as on potential changes to those rules and policies. The Aluminum Association, the American Chemistry Council, the American Forest and Paper Association, the American Public Power Association, Blue Ridge Power Agency, the California Municipal Utilities Association, the California Public Utilities Commission, the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California, the Electricity Consumers Resource Council, the Industrial Energy Consumers of America, Maryland Office of People's Counsel, the Modesto Irrigation District, the National Association of State Utility Consumer Advocates, the New York Public Service Commission, Northern California Power Agency, the Office of the People's Counsel for the District of Columbia, the Public Utility Law Project of New York, the Transmission Agency of Northern California, and the Virginia Office of the Attorney General Division of Consumer Counsel

[1] *Inquiry Regarding the Commission's Elec. Transmission Incentives Policy*, 166 FERC ¶ 61,208 (2019), 84 Fed. Reg. 11,759 (March 28, 2019), *correction published*, 84 Fed. Reg. 13,033 (April 3, 2019).

[2] 16 U.S.C. § 824s.

(collectively, "Joint Commenters") have joined together on these initial comments to promote incentive policies that ensure just and reasonable rates for the benefit of consumers.[3]

I. INTRODUCTION AND OVERVIEW

Joint Commenters are a diverse group composed of state public utility commissions, industrial users of electricity, public power utilities, consumer advocates, and associations representing such entities.[4] We all share the conviction, however, that transmission customers and end use consumers should pay only just and reasonable rates for transmission service under the FPA. Joint Commenters also support beneficial transmission infrastructure development. We recognize that prudently-planned transmission can benefit consumers by increasing supply options, reducing congestion-related costs, integrating renewable resources, and promoting grid reliability and resilience. The issue presented by the NOI is not whether transmission investment can benefit consumers; rather, the overarching question is whether the Commission's existing transmission incentive policies under FPA section 219 remain appropriate in the current industry environment.[5]

The Commission's existing approach to evaluating project-specific incentive applications is generally sound. The current framework was established in Order No. 679 and subsequent orders.[6] While retaining the regulations promulgated in Order No. 679, the Commission refined

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[3] A description of each of the Joint Commenters and their respective contact information is included in the appendix to these comments.

[4] Joint Commenters have come together as an *ad hoc* group to prepare these consensus-based comments for the Commission's review and consideration. As with any such group, while Joint Commenters generally support the policy recommendations set out in these comments, not every Joint Commenter necessarily fully supports every position set out in them. Some of the Joint Commenters may also be filing individual comments in this docket and/or joining in additional comments being filed by other groups. Hence, the fact that Joint Commenters have submitted these comments should not be taken as an indication that any of the Joint Commenters share other positions expressed in other sets of comments being filed by other Joint Commenters in this docket.

[5] *See* Incentive NOI at P 2.

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

its approach to awarding incentives in a 2012 policy statement that principally revised the Commission's "nexus test," particularly for applicants seeking return on equity ("ROE") adder incentives.[7] The 2012 Policy Statement emphasized the need for applicants to mitigate project risks, including requesting risk-reducing incentives, prior to seeking an incentive ROE adder based on project risks and challenges that are not reflected in the base ROE and cannot be adequately mitigated.[8] This emphasis on risk-reducing incentives has been particularly important to striking an appropriate balance between consumer and investor interests in awarding incentives.

While the Commission's rules and policies for evaluating project-specific transmission incentive requests are generally appropriate, Joint Commenters recommend a number of improvements to the current framework, designed largely to better harmonize the Commission's transmission planning and incentive policies. Joint Commenters recommend more substantial changes to the Commission's policies for granting non-project-specific incentives, including the 50 basis point ROE adder available for participation in a Commission-approved regional transmission organization ("RTO") or independent system operator ("ISO") and ROE adders granted to transmission-only companies ("Transcos"). These ROE adders should be eliminated entirely, or at least substantially reformed.

Where such changes are needed to the Commission's incentive rate policies, it is because the current approach does not adhere to the requirements of FPA section 219 and well-

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[7] *See Promoting Transmission Investment Through Pricing Reform,* 141 FERC ¶ 61,129 (2012) ("2012 Policy Statement"); *see also* Incentive NOI at PP 9-10.

[8] The risk-reducing incentives include allowing 100 percent of construction work in progress ("CWIP"), recovery of 100 percent of pre-commercial costs, and recovery of 100 percent of prudently-incurred transmission project costs when the project is abandoned for reasons outside the applicant's control. *See* 2012 Policy Statement at P 11. These risk-reducing incentives may be contrasted with return-enhancing incentives such as ROE adders or hypothetical capital structures.

established principles governing just and reasonable incentive rates, including that incentives must benefit consumers, must not be more than necessary to encourage the desired outcomes, and must not be awarded to encourage actions that utilities are already obligated to take. The Commission's current rules and policies for RTO participation adders and incentive adders for Transcos do not adhere to the applicable statutory and judicial requirements for incentive rates, and to the extent that these generous ROE adders were ever justified, they are no longer supportable in their current form.

There is certainly no demonstrable need to liberalize the Commission's basic approach to considering project-specific incentives – particularly ROE adders – to promote transmission investment at this time. The incentive rate provisions of FPA section 219 were enacted in 2005 in response to a "long decline in transmission investment."[9] This decline in investment has been arrested and reversed in the nearly fourteen years since the Energy Policy Act of 2005 went into effect. Industry statistics indicate that investment in transmission facilities has been at record levels in recent years, suggesting that transmission owners are not forgoing transmission development opportunities for want of more robust incentives. Reasonable base ROEs are sufficient to attract capital, and the broad shift to formula rates has reduced cost recovery risk.

The increase in transmission investment in recent years has caused a corresponding rise in the transmission costs paid by customers in many regions of the country. These transmission cost increases have imposed a significant burden on consumers, and the Commission should not add to this burden by making it easier for applicants to receive incentives, particularly return-enhancing incentives, that are not needed to promote beneficial transmission development.

[9] Order 679-A at P 3.

While industry data show that transmission investment has been extremely robust in recent years, a common thread running through many of the questions in the Incentive NOI is whether the "right" kind of transmission is being built, and, in particular, whether the Commission should try to encourage projects that might provide particular benefits or that reflect certain project characteristics.[10] Joint Commenters agree it is reasonable to ask whether the most beneficial and cost-effective transmission is being built, but we submit that this is principally a planning issue, not a question of incentives. Open and transparent planning processes under Order No. 890[11] and Order No. 1000[12] should identify beneficial and cost-effective transmission – including interregional projects – and incentives generally should not be necessary to promote this infrastructure. To the extent more beneficial transmission is not being built, there is no evidence that this reflects a flaw in the Commission's incentives policy. Rather, such concerns signify either a lack of need on a region-specific basis, problems with the planning process itself, or the existence of other obstacles to building beneficial grid infrastructure that cannot be solved simply by "throwing money at the problem."

With this general background, Joint Commenters highlight the following key positions set forth in these comments:

- The existing framework established under Order No. 679 and the 2012 Policy Statement for evaluating applications for project-specific incentives remains generally sound.

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[10] *See, e.g.*, Incentive NOI at PP 19-20.

[11] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, 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*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) ("Order No. 890").

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

- Eliminating the Commission's current requirement to show that incentives are needed to address the risks and challenges of a particular project would not comply with FPA section 219.
- The Commission should consider requiring approval of a project in a Commission-approved regional transmission planning process as a prerequisite for receiving incentive rate treatment under FPA section 219.
- The Commission's suggestion that it might grant incentives based solely on the "expected benefit" of a project or a project's "characteristics" would not comply with FPA section 219 and would conflict with the Commission's regional planning rules and policies.
- If the Commission were to change its rules and grant incentives based on an "expected benefits" or "project characteristics" approach, it should condition any approval of project-specific incentives upon: (1) the project being approved in the regional transmission planning process; (2) the submission of evidence demonstrating that there is a causal relationship between each incentive sought and the consumer benefits to be derived from that incentive; and (3) a demonstration through a cost-benefit analysis that the benefits to be gained by consumers materially exceed the costs of the requested incentives.
- Regardless of any changes to the Commission's general framework for evaluating applications for project-specific benefits, the Commission should continue to evaluate incentives on a case-by-case basis; there should be no "automatic" awarding of incentives, even for projects approved in a regional transmission planning process.
- To encourage expanded joint ownership opportunities for non-public utilities, the Commission should retain and enhance its current approach to promoting joint ownership through its transmission incentive policies. The Commission should require applicants for project-specific transmission incentives to explain whether opportunities for joint ownership in the project were offered to non-public utilities within the project sponsor's service footprint that will bear a portion of the project cost, and, if not, why not. Any project for which joint ownership arrangements may have been feasible but were not

pursued should face heightened scrutiny in seeking incentives, particularly return-enhancing incentives.

- The Commission should eliminate the incentive ROE adder for Transcos. If the Commission maintains some form of Transco incentive, it should only be available to entities that are fully independent of market participants, and the incentive should not apply to assets acquired by Transcos.
- The Commission should reconsider its policy of pre-authorizing incentives for yet-to-be-formed affiliates.
- The Commission should eliminate the 50 basis point ROE adder granted for joining an RTO/ISO or remaining a member of an RTO/ISO. If the Commission does not eliminate the adder altogether, the adder should phase down over time to reflect the distinction between an incentive to encourage joining an RTO/ISO and one for voluntarily remaining an RTO/ISO member.
- Project-specific ROE adders should sunset after 15 years, unless, prior to the sunset date, the Commission makes a determination that the adder is no longer needed or effective.
- The Commission should require a project developer to file a notice of any material change in the status of a transmission project following a Commission determination to grant incentives, akin to the reporting requirement for sellers with market-based rate authority.
- As part of its application for an incentive, a public utility should be required to submit a measurement and verification plan designed to track and quantify the consumer benefits generated by its project as well as compare actual data against the projections included in the initial application.

II. COMMENTS

These comments are organized to track the issues and numbered questions in the Incentive NOI. Each subpart begins by quoting (in italics) the NOI question(s) to which Joint Commenters are responding. Where doing so adds clarity and avoids repetition, we group and respond collectively to consecutive questions.

A. Approach to Incentive Policy

1. Incentives Based on Project Risks and Challenges

Q 1) Should the Commission retain the risks and challenges framework for evaluating incentive applications?

The Commission's regulations generally require an applicant for incentives to make a two-part showing. *First,* the applicant must demonstrate "that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219."[13] This requirement implements the statutory directive contained in FPA section 219(a).[14] *Second*, the applicant must show "that the *total* package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project."[15] The applicant must also demonstrate "that resulting rates are just and reasonable."[16] This existing approach for evaluating applications for project-specific incentives, as clarified in the 2012 Policy Statement, remains generally sound, and Joint Commenters do not believe there is any demonstrable need to fundamentally alter the Commission's current approach. Certainly there is no basis for eliminating the requirement to show a nexus between the incentive requested and the project's

[13] 18 C.F.R. § 35.35(d) (2019).

[14] 16 U.S.C. § 824s(a) (providing that the Commission "shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."). The regulations establish a rebuttable presumption that a project satisfies this benefit requirement if the project: (1) "results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission;" or (2) "has received construction approval from an appropriate state commission or state siting authority." 18 C.F.R. § 35.35(i) (2019). The presumption does not apply if "these approval processes do not require that a project ensures reliability or reduce the cost of delivered power by reducing congestion," and the applicant bears the burden of demonstrating that its project satisfies these criteria. *Id.*

[15] 18 C.F.R. § 35.35(d) (2019) (emphasis in the original).

[16] *Id.*

risks and challenges, and dispensing with this approach in favor of an "expected benefits" or "project characteristics" framework would fail to comply with FPA section 219.

a. There is No Demonstrable Need to Change the Commission's General Framework for Evaluating Applications for Project-Specific Incentives

Neither the current record on transmission investment, nor the reasons offered by the Commission for re-examining its transmission incentive policies support fundamental changes to the framework for how the Commission evaluates applications for project-specific incentives.[17] The Commission's 2012 Policy Statement appropriately reframed the nexus test to focus more directly on the requirements of Order No. 679, setting the expectation that applicants will take all reasonable steps to mitigate the risks of a project, including requesting risk-reducing incentives and considering project alternatives, before seeking an incentive ROE based on a project's risks and challenges.[18] Prior to the issuance of the 2012 Policy Statement, the Commission routinely awarded ROE incentive adders that, Joint Commenters submit, were not justified by any need to promote investment in the relevant transmission projects. The Commission's post-2012 approach has resulted in fewer individual transmission projects being granted incentive ROE adders, while still allowing the Commission to address project risks and challenges through risk-reducing incentives where they are shown to be warranted.

[17] As discussed below, changes to the Commission's current incentives policies are warranted with respect to the *duration* of project-specific incentives. The Commission should also revisit its current policies for granting RTO/ISO participation and Transco ROE adders. Joint Commenters also propose a number of changes to the Commission's framework for project-specific incentives designed largely to better align the Commission's incentive policies with its rules and policies governing local, regional, and interregional transmission planning under Order Nos. 890 and 1000.

[18] *See* 2012 Policy Statement at P 16. The 2012 Policy Statement also appropriately set forth the expectation that the applicant seeking a project-specific ROE incentive commit to limiting the ROE incentive to a cost estimate, *e.g.*, the cost estimate utilized at the time of RTO approval. *Id.* at P 28.

Current levels of transmission investment indicate no need to liberalize the current approach to project-specific incentives. Section 219 of the FPA was enacted at a time when the industry had experienced a "long decline in transmission investment."[19] Today, transmission investment is robust, and there is no basis to conclude that transmission owners and developers are withholding investment for want of more lucrative incentives. The Edison Electric Institute's ("EEI") most recent public data on actual and projected transmission investment show that investor-owned utilities and stand-alone transmission companies planned to invest $23.7 billion in transmission assets in 2018.[20] That figure is more than 50 percent higher than the level of investment EEI reported for 2012 ($15.6 billion). EEI projects annual transmission investment to continue in excess of $20 billion per year through at least 2021.[21] A recent report by The Brattle Group ("Brattle") prepared for LSP Transmission Holdings, LLC confirmed an increased level of transmission investment in recent years, showing that annual transmission investments rose from $10.8 billion in 2010 and have hovered in the $19-$21 billion range since 2013.[22] The report explained that "U.S. investments in electric transmission facilities have grown from approximately $2 billion per year during the late 1990s to approximately $20 billion per year during the last five years," with investments in ISO/RTO regions and ERCOT accounting for over 80 percent of the recent level of transmission investments.[23] A February 9, 2018 article published by the Energy Information Administration ("EIA") similarly noted that spending on

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[19] Order 679-A at P 3.

[20] *See* "Historical and Projected Transmission Investment," *available at* http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf.

[21] *Id.*

[22] The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission Experience to Date and the Potential for Additional Customer Value* at 16 (April 2019) ("Brattle Report"), *available at*: https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf.

[23] *Id.* at 14-15.

transmission infrastructure "has increased steadily over the past 10 years [2006-2016] as utilities build, upgrade, and replace station equipment, poles, fixtures, and overhead lines and devices."[24] Citing information from FERC reports, EIA calculated that public utilities (representing about 70 percent of total U.S. electric load) spent approximately $21 billion on capital additions in 2016.[25] And where transmission projects have been subject to competitive selection in regional planning processes, there has been significant vying for the opportunity to construct new transmission infrastructure (and earn FERC-authorized returns on the investment).[26]

It is also important to acknowledge the role that transmission formula rates have played in reducing transmission cost recovery risk in FERC-jurisdictional rates since FPA section 219 was enacted in 2005. In Order No. 679, the Commission "continue[d] to encourage public utilities to explore the benefits of filing transmission-related formula rates,"[27] having agreed that "formula rates can provide certainty of recovery that is conducive to large transmission expansion programs."[28] The Commission's encouragement has paid off, as "the vast majority of public utilities now use formula rates rather than stated rates."[29] The practical effect of "this

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[24] EIA, "Utilities continue to increase spending on transmission infrastructure" (Feb. 9, 2018), *available at*: https://www.eia.gov/todayinenergy/detail.php?id=34892.

[25] *Id.*

[26] *See, e.g.*, *Pub. Serv. Elec. & Gas Co. v. PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,229 (2015); *American Transmission Company, LLC v. Midwest Independent System Operator, Inc.*, 142 FERC ¶ 61,090 (2013); *ITC Midwest, LLC v. American Transmission Company, LLC*, 142 FERC ¶ 61,096 (2013); *Xcel Energy Services, Inc. v. American Transmission Company, LLC*, 140 FERC ¶ 61,058 (2012).

[27] Order No. 679 at P 386.

[28] *Id.*; *see also, e.g., Niagara Mohawk Power Corp.*, 124 FERC ¶ 61,106, at P 33 (2008), *order on reh'g*, 126 FERC ¶ 61,173 (2009) (agreeing "that having a formula cost recovery system in place should eliminate the need for frequent rate adjustment filings, ensure that rates reflect the actual cost of providing transmission service, and incent needed transmission investment," and noting that "[t]he Commission has found that the use of formula rates encourages the construction and timely placement into service of needed transmission infrastructure and has approved the use of formula rates by a number of transmission-owning utilities.").

[29] *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117, at P 15 (2018).

near-industry-wide transition from stated to formula rates"[30] should be an across-the-board reduction in the need for transmission incentives since formula rates themselves can "incent needed transmission investment."[31]

While transmission investment has grown significantly since section 219 was enacted in 2005, the record is unclear regarding how instrumental, if at all, transmission incentives under Order No. 679 have been in driving this investment. Because the Commission declined to adopt a "but for" requirement for incentives in Order No. 679,[32] there is no way to know for sure, after the fact, whether the incentives promoted investment or simply provided benefits to transmission owners for projects they would have undertaken anyway. One notable data point, however, is that, according to the EEI, Brattle, and EIA figures cited above, there was no drop-off in transmission investment after the Commission issued its 2012 Policy Statement, which scaled back the award of incentive ROE adders. To the contrary, transmission investment increased significantly in the years following 2012. This suggests that project-specific ROE adders did not (and do not) play a major role in driving transmission investment. While it is logical to think that risk-reducing incentives helped promote transmission, the uncertain record concerning the efficacy of incentives does not provide a basis for significant changes to the Commission's current policy for evaluating project-specific incentive requests.

The Commission observes in the Incentive NOI that, in the nearly 13 years since it issued Order No. 679, "the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably."[33] The Commission points, in particular, to "issuance

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[30] *Id.* at P 16.

[31] *Niagara Mohawk*, 124 FERC ¶ 61,106, at P 33.

[32] *See* Order No. 679 at P 48.

[33] Incentive NOI at P 13.

of Order No. 1000, an evolution in the generation mix and the number of new resources seeking transmission service, shifts in load patterns, and an increased emphasis on the reliability of transmission infrastructure."[34] To be sure, there have been significant changes in the transmission landscape in the years since Order No. 679. Nothing about these industry changes, however, warrants a departure from the current "risks and challenges" framework for evaluating applications for project-specific transmission incentives. If anything, the increased complexity of planning and developing transmission *supports* the need for a robust application of the nexus test under the Commission's current regulations to ensure that "incentives are not provided in circumstances where they do not materially affect investment decisions."[35]

Notwithstanding the increased pace of transmission investment in recent years, Joint Commenters are cognizant of, and often share in, concerns that potentially beneficial transmission project proposals do not always come to fruition, and that the projects that are built may not necessarily be the most cost-effective or efficient for consumers. For instance, concerns have been raised in both PJM Interconnection ("PJM") and the California Independent System Operator ("CAISO") about the extent to which very significant transmission investment dollars have been devoted to projects developed outside the full RTO/ISO transmission planning process with limited or no opportunity for stakeholder review.[36] Joint Commenters do not believe, however, that transmission incentives – particularly of the revenue-enhancing kind – are the solution to concerns about whether the industry is building the "right" kind of transmission. To the extent the record evidence reveals that appropriate levels of necessary and beneficial

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[34] *Id.*

[35] Order No. 679-A at P 25; *see also* Order No. 679 at P 26.

[36] *See Cal. Pub. Utils. Comm'n v. Pacific Gas & Elec. Co.*, 164 FERC ¶ 61,161 (2018), *reh'g pending*; *Monongahela Power Co.*, 162 FERC ¶ 61,129*, reh'g denied*, 164 FERC 61,217 (2018).

transmission are not being built in particular areas, the Commission should allow stakeholders to assess, on a region-specific basis, the factors that may be leading to such a result, including review of factors such as permitting/siting issues, the transmission planning process, cost allocation methodologies, and other considerations.

b. The Commission Should Not Pursue Unnecessary Incentive Rate Rule Changes that Could Increase the Already Significant Cost Burdens on Transmission Customers

In considering changes to its current incentive policies, it is essential for the Commission to keep in mind that the increased level of transmission investment in recent years has led to a significant rise in the transmission costs paid by customers in many regions of the country. A 2017 analysis of transmission rates in PJM by American Municipal Power, Inc. ("AMP"), for example, found that the total annual revenue requirement for transmission enhancements increased by 294.5 percent from 2011 to 2017.[37] Over the past five years, transmission rates have steadily increased in RTO/ISOs. In PJM, for example, transmission costs increased from $5.65 to $9.47 per megawatt-hour, or 68 percent.[38] For CAISO, total transmission charges increased from $2.7 billion to $3.2 billion over this same time period, equal to 19 percent,[39] and in ISO New England Inc. ("ISO-NE"), total transmission costs increased from $1.8 to $2.3 billion, or 28 percent.[40] Last summer, NEPOOL forecast ISO-NE's Regional Network Service rates to increase to $135 per kilowatt-year in 2022, compared to the current rate of $112, another

[37] A copy of the AMP analysis is available at: https://www.amppartners.org/Assets/AMP_Rose_Transmission.pdf.

[38] 2018 State of the Market Report for PJM, Monitoring Analytics, LLC, Table 1-10 (March 14, 2019).

[39] California Independent System Operator Corporation, Five Year Summary of Comparable Statistics, 2014-2018 (May 3, 2019) and 2013 – 2017 (April 30, 2018).

[40] 2018 Annual Markets Report, Internal Market Monitor, ISO New England, Inc. Internal Market Monitor, Figure 2.1, (May 23, 2019).

21 percent increase.[41] EIA's 2019 Annual Energy Outlook projects that rising transmission and distribution costs will offset much of the projected decrease in generation costs through 2050.[42] It would be difficult to overstate the significance of the concerns that many customers currently have about rising transmission costs. The Commission should not increase this burden by adopting rule or policy changes that would make it easier for transmission owners and developers to receive project-specific incentives – particularly return-enhancing incentives.

c. Eliminating the Risks and Challenges Framework Would Not Comply with FPA Section 219

In addition to requiring that incentives "benefit[] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion,"[43] FPA section 219 specifically dictates that all incentive rates awarded pursuant to that provision must be just and reasonable and not unduly discriminatory or preferential.[44] Eliminating the "risks and challenges" element of the Commission's framework for evaluating project-specific incentives (in favor of an "expected benefits" or "project characteristics" approach) would contravene the just and reasonable rate requirement of FPA section 219.

As an initial matter, because the Commission's existing *regulations* promulgated in Order No. 679 require applicants to establish that a project will provide benefits *and* that the total package of incentives is tailored to the project's risks and challenges,[45] the existing framework could only be modified by a further rule preceded by notice and the opportunity for public

[41] RNS Rates: 2018-2022 PTF Forecast, NEPOOL Reliability Committee/Transmission Committee – Summer Meeting, Slide 5 (August 7 & 8, 2018).

[42] EIA, *Annual Energy Outlook 2019* at 98.

[43] 16 U.S.C. § 824s(a).

[44] 16 U.S.C. § 824s(d).

[45] 18 C.F.R. § 35.35(d) (2019).

comment.[46] Unlike the 2012 Policy Statement, which simply provided guidance on how the Commission would apply the existing regulations, a shift to exclusive reliance on "expected benefits" or "project characteristics" as the basis for awarding project-specific benefits would be a significant amendment to the current regulations, which specifically require a showing that the incentives are tailored to the project's "demonstrable risks and challenges."[47] Joint Commenters reserve their right to comment on any rule proposing to modify the existing regulations, if and when it is issued by the Commission.

The "risks and challenges" component of the current incentives framework implements the Commission's "nexus" requirement for project-specific incentives.[48] The Commission adopted the nexus test with the objective of ensuring that "incentives are not provided in circumstances where they do not materially affect investment decisions."[49] Incentives granted under FPA section 219 are not simply a "bonus for good behavior,"[50] and the nexus between incentives and investment is needed to ensure that the Commission's rules "continue to meet the just and reasonable standard by achieving the proper balance between consumer and investor interests on the facts of a particular case . . . ."[51] In Order No. 679 the Commission explained that "Section 219(a) states that transmission incentives should be '*benefitting consumers* by ensuring reliability and reducing the cost of delivered power by reducing transmission

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[46] *See, e.g.*, *Perez v. Mortgage Bankers Assn*, 135 S. Ct. 1199, 1206 (2015); *Clean Air Council v. Pruitt*, 862 F.3d 1, 9 (D.C. Cir. 2017).

[47] 18 C.F.R. § 35.35(d) (2019).

[48] *See generally* 2012 Policy Statement at PP 6-7.

[49] Order No. 679-A at P 25; *see also* Order No. 679 at P 26.

[50] Order No. 679 at P 26 (internal quote omitted).

[51] *Id.*; *see also* 16 U.S.C. § 824s(d) (requiring that all rates approved under the Commission's FPA section 219 implementing regulations must satisfy the just and reasonable requirements of FPA sections 205 and 206).

congestion.'"[52] Accordingly, it is clear that the purpose of Order No. 679 is to "benefit consumers by providing real incentives to encourage new infrastructure, not simply increasing rates in a manner that has no correlation to encouraging new investment."[53]

The requirement to show a nexus between the incentives and project investment conforms the Commission's regulations to precedent requiring the Commission, in awarding rate incentives under the just and reasonable standard, to "see to it that the increase is in fact needed, and is no more than is needed, for the purpose."[54] Evaluating applications for project-specific incentives to ensure that there is a nexus between the incentive and the applicant's investment decision is also necessary to verify that incentives are not awarded for actions that a utility has already taken or is already required to take.[55] Thus, to the extent that the NOI is inquiring whether the Commission *should* eliminate the current "risks and challenges" component from its regulations, the answer is that the Commission *cannot* do so, as this would sever the link between incentive and project investment necessary to comply with the FPA's just and reasonable requirement, in contravention of FPA section 219.

d. The Commission Should Consider Limiting Incentives to Projects Approved in a Regional Transmission Planning Process

Although Joint Commenters believe the Commission's current framework for evaluating project-specific incentive requests is generally sound, a change to the current model that the

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[52] Order No. 679 at P 6 (emphasis in the original).

[53] *Id.*

[54] *Farmers Union Cent. Exch. Inc. v. FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984) (quoting *City of Detroit*, 230 F.2d 810, 817 (D.C. Cir. 1955)); *see also San Diego Gas & Elec. Co. v. FERC*, 913 F.3d 127, 137 (D.C. Cir. 2019) ("*SDG&E v. FERC*") (finding that the Commission's prospective application of the abandonment incentive "aligns with its longstanding policy that rate incentives must be prospective and that there must be a connection between the incentive and the conduct meant to be induced." (internal quotes and cites omitted)); *City of Charlottesville v. FERC*, 661 F.2d 945, 953-54 (D.C. Cir. 1981).

[55] *Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966 (9th Cir. 2018) ("*CPUC v. FERC*"); *SDG&E v. FERC*, 913 F.3d 127.

Commission should consider is making approval of a project in a regional transmission planning process a prerequisite for an award of incentives, particularly return-enhancing incentives. Order No. 679, while noting the important role of a regional planning process in identifying beneficial projects,[56] stopped short of requiring approval of a project through a regional transmission planning process as an absolute prerequisite for incentives.[57] In the ensuing years, however, the Commission has made coordinated regional planning a priority, including through the reforms carried out in Order No. 890 and Order No. 1000. The 2012 Policy Statement also emphasized the expectation that applicants for return-enhancing incentives would show that "alternatives to the project have been, or will be, considered in either a relevant transmission planning process or another appropriate forum."[58] In recognition of the Commission's policies in favor of coordinated regional planning to ensure just, reasonable and non-discriminatory service, and to provide greater assurance that projects awarded return-enhancing transmission incentives in particular will likely provide consumer benefits that justify the incentives, the Commission should consider requiring approval of a project in a Commission-approved regional transmission planning process as a prerequisite for receiving incentive rate treatment under FPA section 219.

> *Q 2) Is providing incentives to address risks and challenges an appropriate proxy for the expected benefits brought by transmission and identified in section 219 (i.e., ensuring reliability or reducing the cost of delivered power by reducing transmission congestion)? If risks and challenges are not a useful proxy for benefits, is it an appropriate approach for other reasons?*

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[56] *See* Order No. 679 at P 58 ("Regional planning processes can help determine whether a given project is needed, whether it is the better solution, and whether it is the most cost-effective option in light of other alternatives . . . ."); *see also* 2012 Policy Statement at PP 25-26.

[57] Order No. 679 at P 58. In a number of subsequent specific cases, however, the Commission conditioned preliminary awards of incentives on subsequent approval of a project in an ISO/RTO transmission planning process. *Central Maine Power Co.*, 125 FERC ¶ 61,182 (2008), *requests for reh'g dismissed*, 129 FERC ¶ 61,153 (2009), *reh'g denied,* 135 FERC ¶ 61,236 (2011); *Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009), *reh'g denied*, 130 FERC ¶ 61,117 (2010); *So. Cal. Edison Co.*, 129 FERC ¶ 61,246 (2009), *order on compliance filing and granting partial rehearing*, 133 FERC ¶ 61,108 (2010), *order denying request for clarification or reh'g*, 133 FERC ¶ 61,254 (2010).

[58] 2012 Policy Statement at P 25.

Joint Commenters dispute the premise of Question No. 2. The focus on risks and challenges under Order No. 679 and the 2012 Policy Statement was not intended as a "proxy for the expected benefits brought by transmission and identified in section 219." As explained in response to Question No. 1 above, the Commission is obligated to find project benefits *as well as* that the package of incentives is tailored to address the risks or challenges of a particular project. Except as we otherwise explain in these comments, Joint Commenters believe the Commission's current framework is generally appropriate for evaluating new applications for project-specific incentives.

> *Q 3) The Commission currently considers risks both in calculating a public utility's base ROE and in assessing the availability and level of any ROE adder for risks and challenges. Is this approach still appropriate? If so, which risks are relevant to each inquiry, and, if they differ, how should the Commission distinguish between risks and challenges examined in each inquiry?*

The Commission's current approach to considering new applications for project-specific ROE adders is generally still appropriate. Consistent with the 2012 Policy Statement, risk mitigation measures, including risk-reducing incentives and consideration of alternatives, should be applied before an incentive ROE is considered.[59] Project-specific ROE adders should be rare, and should be reserved for only the most challenging projects. Awarding a project-specific ROE adder should require a case-specific showing that the project's risks and challenges are not already reflected in the base ROE, that the risks and challenges cannot be adequately mitigated by risk-reducing incentives and other measures (such as joint ownership), and how the incentive ROE will promote the project. Further, the Commission should continue to apply its expectation, as set forth in the 2012 Policy Statement, that the incentive ROE would be limited to

[59] 2012 Policy Statement at P 16.

a cost estimate.[60] The Commission's recent order in *United Illuminating Company*[61] provides a timely example of how the current policy works to mitigate project risks, while ensuring that customers are not burdened with incentive ROE adders for projects that do not "face[] risks and challenges either not already accounted for in [the applicant's] base ROE or addressed through risk-reducing incentives."[62]

A transmission owner's base ROE established using a risk-appropriate transmission proxy group or other reasonable estimate of the cost of equity for a transmission company necessarily should reflect most typical transmission company risks.[63] Indeed, the base ROE likely over-compensates investors for many transmission projects since a proxy-group-derived ROE may reflect business and financial risks that are not wholly comparable to the risks of a transmission provider.[64] There may be unusual situations where a specific transmission project faces risks and challenges that are not representative of the risks of transmission operation and a project-specific incentive ROE adder might be considered. The Commission's current policy allows for the consideration of such situations. Any award of an incentive ROE applicable to a

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[60] *Id.* at P 28.

[61] 167 FERC ¶ 61,126 (2019), *reh'g pending*.

[62] *Id.* at P 62.

[63] *Cf. Petal Gas Storage v. FERC*, 496 F.3d 695, 699-700 (D.C. Cir. 2007) (vacating a Commission decision approving an authorized ROE for a natural gas pipeline because the proxy group companies were not shown to be risk-appropriate for calculating an ROE for an interstate natural gas pipeline company). The base ROE for an individual utility can be further calibrated based on a showing of below- or above-average business or financial risks.

[64] The Commission has insisted that cost of capital must be evaluated on an enterprise, rather than unbundled or functional, basis and specifically has rejected attempts to demonstrate that provision of transmission service generally is less risky than other aspects of an integrated company's business. *See, e.g.*, *Otter Tail Power Co.*, 12 FERC ¶ 61,169, at p. 61,414 (1980); *Minn. Power & Light Co.*, 12 FERC ¶ 61,264, at pp. 61,626-27 (1980), *aff'd sub nom. Cities of Aitken v. FERC*, 704 F.2d 1254 (D.C. Cir. (1982)); *Conn. Light and Power Co.*, 43 FERC ¶ 61,508, at pp. 62,265-66, *order on reh'g*, 45 FERC ¶ 61,370, at pp. 62,164-68 (1988); *Boston Edison Co.*, 79 FERC ¶ 61,328 (1997); *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292, at PP 11-12 (2002).

particular project (or any other project-specific incentive), however, requires a case-by-case analysis.

Joint Commenters reiterate that awarding project-specific incentive ROEs should be the exception and not the rule. While public utility transmission owners might understandably prefer to collect elevated equity returns, Joint Commenters submit that risk-reducing incentives are more likely to promote necessary infrastructure development at a reasonable cost than return-enhancing incentives. Risks are likely to change over time, and a return-enhancing incentive that may be reasonable at one stage of a project's development may overcompensate for risks or under-compensate for risks, if the risks are assessed at a different stage.[65] By contrast, the benefits of risk-reducing incentives are both more certain and more durable and, therefore, more likely to achieve the intended results.

2. Incentives Based on Expected Project Benefits

Q 4) Would directly examining a transmission project's expected benefits improve the Commission's transmission incentives policy, consistent with the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework?

The Commission questions if, in lieu of the risks and challenges framework for evaluating transmission incentive requests, "[t]he Commission could instead evaluate incentive requests based on the transmission project's potential to achieve benefits related to reliability and reductions in the cost of delivered power by reducing transmission congestion."[66] Many, if not most, of the individual questions in the NOI relate to an incentive approach that focuses on expected benefits or on project characteristics as a proxy for expected benefits.[67] Joint

[65] Indeed, as discussed in response to Question No. 83 below, project-specific ROE adders should remain effective for no more than 15 years.

[66] Incentive NOI at P 16.

[67] *See id.* at PP 16, 19-20.

Commenters do not believe that such a shift to an "expected benefits" framework for evaluating transmission incentives is warranted or appropriate, and, as explained elsewhere, such an approach would be inconsistent with the Commission's obligations under FPA section 219.

The suggestion that the Commission might evaluate incentive requests based on a "project's potential to achieve benefits related to reliability and reductions in the cost of delivered power by reducing transmission congestion,"[68] disregards the fact such an assessment of project benefit is already a prerequisite to awarding project-specific incentives, as Joint Commenters explained above. The response to Question No. 1 explains that evidence of benefits is *required*, but not *sufficient*, to satisfy the requirements of FPA section 219 for granting transmission investment incentives. The Commission should not – and legally could not – dispense with consideration of project-specific risks and challenges to focus exclusively on project benefits as the basis for awarding incentives. Joint Commenters' response to Question No. 1 explained that application of a nexus test focusing on project risks and challenges is required to comply with the requirement that incentives granted pursuant to FPA section 219 must be just and reasonable and not unduly discriminatory or preferential.[69]

A framework for evaluating project-specific transmission incentives that focuses exclusively on expected project benefits would also be at odds with the Commission's rules and policies governing local, regional, and interregional transmission planning. While, as noted above, Order No. 679 did not make approval of a project through a regional transmission planning process an absolute prerequisite for incentives,[70] the Commission recognized the

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[68] *Id.*

[69] 16 U.S.C. § 824s(d).

[70] Order No. 679 at P 58.

important role of a regional planning process in identifying beneficial projects.[71] Since the rules implementing FPA section 219 were adopted in Order No. 679, the Commission has only reinforced and expanded the importance of coordinated regional planning, including the issuance of Order Nos. 890 and 1000.

Order No. 890 required, among other things, that all public utility transmission providers participate in a coordinated, open, and transparent planning process on both a local and regional level.[72] The planning processes were required to meet nine planning principles described in the rule.[73] The Commission found in Order No. 890 that it could not "rely on the self-interest of transmission providers to expand the grid in a non-discriminatory manner."[74] The Commission, in adopting the transmission planning reforms, also cited its obligations under section 217 of the FPA[75] "to exercise its jurisdiction in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of [load-serving entities]."[76] Addressing regional planning in particular, the Commission observed that "[t]he coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis."[77]

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[71] *See id.*; *see also* 2012 Policy Statement at PP 25-26.

[72] Order No. 890 at PP 435-43.

[73] *See id.* Transmission-owning members of RTOs and ISOs were required to comply with the Order No. 890 planning requirements to the extent that they performed "local" transmission planning within an RTO or ISO. *See id.* at P 440; *see also* Order No. 890-A at P 176; *Monongahela Power Co.*, 162 FERC ¶ 61,129 at PP 5-6.

[74] Order No. 890 at P 422.

[75] 16 U.S.C. § 824q.

[76] Order No. 890 at P 425; *see also id.* at P 436.

[77] Order No. 890 at P 524.

Order No. 1000 requires each public utility transmission provider to participate in a regional transmission planning process that satisfies the Order No. 890 planning principles and results in the development of a regional transmission plan.[78] The Commission concluded in Order No. 1000 that projected growth in transmission investment meant that it was particularly important to manage development through reformed transmission planning processes:

> The record in this proceeding and the reports cited above confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges.[79]

The mandatory regional planning processes required by Order No. 1000 are intended to ensure that the "more efficient or cost-effective" solutions are identified to address regional transmission needs. Toward this end, the Order No. 1000 regional planning process must consider transmission needs driven by public policy requirements[80] and must assess transmission and non-transmission alternatives on a comparable basis.[81] Order No. 1000 also adopted requirements for interregional coordination among public utility transmission providers.[82]

Because the mandatory regional planning processes under Order No. 1000 are tasked with identifying the most beneficial projects (*i.e.*, the "more efficient or cost-effective" solutions for regional transmission needs), it would be unreasonable to adopt a rule that would award incentives to projects resulting from such a process merely because they are expected to be

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[78] *See* Order No. 1000 at P 6.

[79] *See id.* at P 46.

[80] *Id.* at P 203.

[81] *Id.* at P 148.

[82] *See id.* at PP 393-404.

beneficial. A properly-functioning regional planning process should *already* be identifying the more efficient or cost-effective projects to ensure reliability and reduce the cost of delivered power by reducing transmission congestion. Indeed, the Commission's regulations establish a rebuttable *presumption* that transmission projects resulting "from a fair and open regional planning process" satisfy the benefits requirements of FPA section 219.[83] A transmission incentive framework focused on promoting benefits that should already be the focus of the regional planning processes is unreasonable and unnecessary. As discussed above, there is nothing to suggest that transmission owners or developers, absent particular project risks and challenges, are unwilling to build regionally-planned projects and recover the costs, including a reasonable return, through Commission-regulated transmission rates, typically formula rates.

Awarding incentives to projects that are *not* reviewed or approved in a regional transmission planning process based on "expected benefits" would be even more problematic, as this could undermine the Order No. 1000 transmission planning process that the Commission has said is crucial for tackling the transmission planning needed in the current energy landscape.[84] An expected benefits approach could make it easier for transmission owners and developers to seek incentives for projects developed on a piecemeal basis outside of the regional planning process, based on the Commission's suggestions of what may constitute incentive-worthy project benefits or characteristics. This could place the Commission in the position of picking winners and losers rather than allowing these decisions to be made as part of the planning process. Considering such proposals could also undermine the Commission's obligations under FPA section 217(b)(4), which the Commission's transmission planning requirements were intended to

[83] 18 C.F.R. § 35.35(i)(1)(i) (2019).

[84] *See* Order No. 1000 at P 46.

address.[85] Even if regional planning process approval is not a legal prerequisite to being awarded incentives, a shift to an expected benefits approach would make it more likely that the Commission would be placed in the position of reviewing "one-off" project proposals without the benefit of the evidence and analysis (including analysis of potential alternatives) from a regional transmission planning process.[86]

To the extent the Commission is concerned that the regional and interregional planning processes in any particular region do not consistently result in the most beneficial transmission projects, such concerns signify either a problem with the planning process itself, or the existence of other obstacles to building beneficial grid infrastructure (*e.g.*, siting challenges) that are unlikely to be solved by changing the Commission's incentive framework to focus exclusively on expected benefits. Transmission incentives policy should not be used to compensate for transmission planning deficiencies.

Even leaving aside these legal and planning obstacles, an "expected benefits" framework would face practical challenges because identifying and quantifying project benefits would be difficult and contentious. Many of the benefit categories and project characteristics the Commission lists in the NOI are not readily quantifiable, including "reliability," "security," "resilience," and flexible transmission system operation. Disputes are certain to arise even as to benefits that might be easier to quantify, such as economic efficiency benefits. Further, transmission facilities are long-lived assets, and the benefits allegedly provided by any particular project at a given point in time may be difficult to discern as time passes and the grid evolves.

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[85] *See* Order No. 890 at PP 425, 436.

[86] As discussed in response to Question No. 7, if the Commission were to adopt an "expected benefits" approach to incentives, it should condition any approval of project-specific incentives upon: (1) the project being approved in the regional transmission planning process; (2) the submission of evidence demonstrating that there is a causal relationship between each incentive sought and the consumer benefits to be derived from that incentive; and (3) a demonstration that the benefits to be gained by consumers materially exceed the costs of the requested incentives.

Addressing such issues would be particularly arduous if the project had not been fully evaluated in a regional transmission planning process.

For the reasons explained above, Joint Commenters do not support the adoption of a "benefits approach," and we do not believe such an approach could be implemented in a manner consistent with FPA section 219 and other legal requirements applicable to the Commission's authority to approve incentive rates. Joint Commenters are generally reluctant to weigh in on how a benefits approach might be implemented, given its substantial flaws. In an effort to be responsive, however, Joint Commenters respond below to certain of the questions included in the Incentive NOI about potential implementation of a "benefits approach" and/or a "project characteristics" approach to awarding incentives. The Commission should not interpret Joint Commenters' responses to these questions as an indication of support for an expected benefits framework or as agreement that such an approach could be structured and administered in a reasonable fashion.

> *Q 5) If the Commission adopts a benefits approach, should it lay out general principles and/or bright line criteria for evaluating the potential benefits of a proposed transmission project? If so, how should the Commission establish the principles or criteria?*

Establishing *ex ante* principles or bright line criteria for when incentives might be warranted under an "expected benefits" approach would likely only exacerbate the potential conflicts with regional and interregional planning processes described above. Applicants might be encouraged to seize upon these principles and/or criteria to propose projects reflecting those attributes outside of the usual regional planning process in pursuit of incentives. If the Commission is in a position to identify general principles and or/criteria that it believes should guide transmission project development, it could propose those principles or criteria as potential

goals of the regional planning process and let stakeholders in their respective regions consider that guidance in the regional planning processes.

> *Q 6) How would a direct evaluation of expected benefits, instead of using risks and challenges as a proxy, impact certainty for project developers?*

Joint Commenters reiterate their observation that the "risks and challenges" framework under Order No. 679 and the 2012 Policy Statement was not intended as a "proxy" for expected transmission benefits, and consideration of such risks and challenges is necessary to comply with the FPA. Case-by-case application of the Commission's currently well-settled requirements should provide an adequate and appropriate level of certainty regarding project-specific incentive awards.

> *Q 7) Should transmission projects with a demonstrated likelihood of benefits be awarded incentives automatically? How could the Commission administer such an approach?*

The Commission should not grant any incentives on an automatic basis. If the Commission were to consider an expected benefits framework for evaluating project-specific incentives, the Commission should adhere to its current approach of considering project applications on a case-by-case basis. Case-specific review of proposed project incentives would remain necessary, even if the Commission were to change its regulations to eliminate the requirement that applicants show that requested incentives are tailored to the demonstrable risks and challenges facing a project.

There are numerous project-specific factors that would require evaluation under an expected benefits approach. For example, even if the Commission were to adopt "bright line criteria for evaluating the potential benefits of a proposed transmission project" as suggested in Question No. 5, an assessment of whether a particular project actually met, or would be likely to meet, the criteria would still be required. Indeed, Question No. 7 itself implicitly acknowledges

that there would need to be a "demonstrated likelihood of benefits" in order to award incentives "automatically." Such a demonstration of benefits, Joint Commenters submit, would need to occur in a proceeding before the Commission where interested parties would have the opportunity to evaluate and, if warranted, challenge claimed project benefits.

Even under an expected benefits approach, satisfying the just and reasonable standard requires individualized review to ensure, among other things, that the applicant is not seeking an incentive for activity it is already required to take,[87] and that the identified benefits justify the costs or risks that that would be placed on consumers as a result of the project. For example, different regions will almost certainly have different levels of need for new or expanded transmission infrastructure, and those regional differences would need to be taken into account in considering how beneficial a project with certain characteristics would be. There would also need to be some causal relationship between the incentives and the project benefits. Even without a "risks and challenges" analysis, the expected benefits could not be so amorphous that projects a transmission provider is required to undertake as part of its core business obligations would satisfy the criteria for eligibility to receive incentives.

Under an expected benefits framework, the Commission should require an applicant for incentives to make a particularized showing of how the proposed project will provide the specific benefit(s) on which the applicant's "expected benefits" proposal rests. While FPA section 219 refers generally to encouraging transmission that "benefit[s] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion,"[88] if the Commission is going to consider awarding incentives based on claims of specific types of

[87] *See, e.g., CPUC v. FERC*, 879 F.3d at 977-78.

[88] 16 U.S.C. § 824s(a).

benefits or project characteristics, the Commission must require substantial evidence that those *specific* benefits are likely to be achieved by the project. As such, the Commission should require a demonstration that there is a causal relationship between each incentive sought and the consumer benefits to be derived from that incentive. As discussed below, the applicant should also be required to provide a cost-benefit analysis showing how the project will result in a net benefit for consumers and that the benefits to be gained by consumers materially exceed the costs of the requested incentives. Thus, for example, if an applicant were to argue that a proposed project is entitled to incentives because it will address a persistent geographic need for transmission in a certain area,[89] the applicant should have the burden to show through detailed evidence how the project would address the need in a way that provides net quantifiable benefits to consumers after the costs of the proposed incentives are taken into account in the calculation of benefits.

Consideration of how a "benefits approach" could be administered also raises questions about the relationship between such an approach and the Commission's regional planning rules and policies. As discussed in response to Question No. 4 above, Joint Commenters believe that an expected benefits approach could conflict with the Commission's efforts to promote regional transmission planning that seeks to identify the most efficient and cost-effective solutions to regional transmission needs. If the Commission proposes to fundamentally alter its existing approach to evaluating transmission incentives by moving to a benefits approach, it should also revisit its decision in Order No. 679 not to condition incentives on approval of the project in a Commission-approved regional transmission plan.[90] The Commission should require, as a

[89] *See* Incentive NOI at P 25.

[90] Order No. 679 at P 58.

prerequisite to receiving incentives, that the project be approved in a Commission-approved regional planning process.[91] Such a condition would both reinforce participation in regional planning and provide greater assurance that projects receiving incentives will actually deliver consumer benefits.[92]

Thus, projects that are not subject to a full regional planning process under Order No. 1000 should be ineligible for transmission incentives under an expected benefits framework. Projects that are planned as part of a transmission provider's "local" transmission planning process subject only to Order No. 890 planning requirements (such as Supplemental Projects in PJM) should not be entitled to incentives. Such projects, Joint Commenters submit, cannot provide adequate assurance that any benefits they might provide are justified in light of potential alternatives and overall regional needs.[93] Finally, under no circumstances should transmission investments that are not, at a minimum, subject to Order No. 890 planning requirements (such as asset maintenance projects in CAISO) be eligible for incentives under an expected benefits framework.

A shift to an "expected benefits" approach would also require modification of the Commission's regulations governing the rebuttable presumption of benefits for projects approved in a regional planning process or by a state siting authority.[94] Under the Commission's current two-part test for evaluating applications for project-specific incentives, if a project has

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[91] As discussed above, Joint Commenters believe the Commission should make regional planning process approval a requirement for project-specific incentives even if the Commission maintains its current framework for evaluating project-specific incentive requests.

[92] While approval or acceptance of a project in a regional plan is a necessary condition for receipt of incentive rate treatment, many projects receiving such approval are routine in nature. Hence, their approval should not automatically qualify such projects for incentive rate treatment.

[93] *See* 2012 Policy Statement at PP 25-26.

[94] 18 C.F.R. § 35.35(i) (2019).

received regional planning process or state siting approval, depending on the nature of the applicable planning or siting process, it may be reasonable to apply a rebuttable presumption that the project will meet the statutory standard of improving reliability or reducing the cost of delivered power, provided that these considerations were part of the planning process. In such a case, the focus shifts to ensuring a sufficient nexus exists between the incentives and the project to ensure that consumers are not supporting incentives that are unnecessary to realize those presumed benefits. If, however, the particular expected benefits of a proposed project were to be the exclusive basis for awarding incentives, it would not be appropriate to presume (even rebuttably) that the regional planning process or state siting approval *alone* signified that the project would provide benefits sufficient to justify an award of incentives under FPA section 219.

If the project developer submits the request for incentives prior to review and approval under a Commission-approved regional transmission planning process, the applicant should face a high hurdle to demonstrate benefits. As explained above, the Commission should further condition any preliminary grant of incentives on subsequent approval under the relevant regional transmission planning process accompanied by evaluation of the specific benefits that were the basis for granting any incentives. If a project is reviewed under a regional transmission planning process and rejected, then the Commission should not allow incentives.[95]

Thus, if the Commission were to adopt an "expected benefits" approach to incentives, it should condition any approval of project-specific incentives upon: (1) the project being approved in the regional transmission planning process; (2) the submittal of evidence demonstrating that

[95] *See, e.g.*, *DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224, at P 38 (2012) (conditioning the grant of incentives on the project being included in the regional transmission expansion plan).

there is a causal relationship between each incentive sought and the consumer benefits to be derived from that incentive; and (3) a demonstration through a cost-benefit analysis that the benefits to be gained by consumers materially exceed the costs of the requested incentives.

> *Q 8) If the Commission grants incentives based on expected benefits, should the level of the incentive vary based on the level of the expected benefits relative to transmission project costs? If so, how should the Commission determine how to vary incentives based on the size of benefits?*

It is unclear what the question means by "the level of the incentive." As explained above, the project-specific incentives the Commission has adopted in its regulations implementing FPA section 219 generally fall into two categories – risk-reducing (*e.g.*, CWIP recovery, full abandoned plant cost recovery, pre-commercial cost recovery) and return-enhancing (ROE adders, hypothetical capital structure). It is the nature of the risk-reducing incentives – which should be used before return-enhancing incentives are considered – that they will vary in proportion to the project cost. Thus, it is unclear how the Commission could calibrate the "level" of these incentives to the ratio of expected benefits relative to project costs.

The question appears, therefore, to be referring implicitly to ROE adders or other return-enhancing incentives. First, Joint Commenters do not support any expanded use of ROE incentive adders. There is no demonstrable need for additional equity adders to spur transmission investment generally. Even if the Commission were to shift to an "expected benefits" or "project characteristics" approach to incentives in order to encourage investment in projects with particular attributes, there is little reason to believe that ROE adders or other return-enhancing incentives are a reasonable way of encouraging such investments.

> *Q 9) Should incentives be conditioned upon meeting benefit-to-cost benchmarks, such as a benefit-cost ratio? If so, what benefit-to-cost ratios should be used?*

> *Q 10) Should incentives be based only on benefit-to-cost estimates or should the Commission condition the incentives on evidence that that those benefit-to-cost estimates were realized?*

Q 11) If an incentive is conditioned upon a transmission developer meeting benefit-to-cost benchmarks, what types of benefits and costs should a transmission developer include, and the Commission consider to support requests for such incentives? Should there be measurement and verification, and if so, over what time period? If expected benefits do not accrue, should the incentive be revoked?

If the Commission fundamentally alters its approach to implementing FPA section 219 by shifting the focus to expected project benefits, the Commission should also revisit its previous refusal to require a specific cost-benefit justification for an award of incentives.[96] The Commission's existing regulations require applicants to establish the benefits of a project and demonstrate that the total package of incentives is narrowly-tailored to address the risks and challenges of that project. Even without a cost-benefit analysis, the requirement to demonstrate that the incentives are narrowly tailored to address project risks and challenges serves as a constraint on any incentives that customers may be asked to support for a given project. Indeed, the Commission cited the applicability of the nexus test as one of its reasons for not adopting a cost-benefit analysis requirement.[97]

By focusing solely on the benefits a project might provide, the check on incentives provided by the nexus test would be eliminated. In that situation, it would be appropriate to require a more detailed and quantified demonstration of benefits by requiring a cost-benefit analysis showing that the benefits of the project exceed the project costs, *inclusive of any requested incentives*. Of course, inflated ROE adders and other revenue-enhancing incentives might actually contradict the goal of building economical transmission projects by artificially raising transmission costs, which could cause some projects to fail cost-benefit tests that they would otherwise pass.

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[96] *See* Order No. 679 at P 65; Order No. 679-A at PP 35-40.

[97] *See* Order No. 679-A at P 40.

Joint Commenters do not take a collective position on whether there should be a minimum cost-benefit ratio for which incentives may be granted. We note, however, that Cost Allocation Principle No. 3 from Order No. 1000 provides that, if a planning region adopts a benefit-to-cost ratio threshold for projects to be included in a regional transmission plan for the purpose of cost allocation, the ratio may not exceed 1.25 absent Commission approval of a greater ratio.[98] If a cost-benefit ratio of 1.25 represents a level that regions may adopt simply for projects to be *included* in the regional plan, Joint Commenters submit that a higher ratio of benefit to cost would be appropriate for incentive rate eligibility premised upon project benefit.

We do not take a position at this time on the specific types of benefits and costs that might be included in a cost-benefit analysis if the Commission were to change its regulations to adopt an "expected benefits" framework under FPA section 219. However, if incentives are awarded on the basis of expected benefits, Joint Commenters support conditioning such incentives on evidence that those benefit-to-cost estimates were realized, as discussed below. Under the Commission's current regulations, the requirement to establish project benefits, coupled with the need to show that requested incentives are "tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project,"[99] provide some assurance that the incentives are not simply a "bonus for good behavior."[100] Rather, the incentives are aimed at overcoming risks and challenges that might otherwise prevent a beneficial project from being built, consistent with the longstanding requirements for just and reasonable incentive rates.[101] Under an "expected benefits" framework where the benefits are the only basis for

[98] *See* Order No. 1000 at PP 646-49.

[99] 18 C.F.R. § 35.35(d) (2019).

[100] Order No. 679 at P 26 (internal quote omitted).

[101] *See Farmers Union*, 734 F.2d at 1503.

granting the incentive, the need for a mechanism to ensure that customers actually get what they pay for would be crucial.

Any shift to an expected benefits approach should be accompanied by more robust mechanisms for tracking and verification of benefits, as Joint Commenters discuss in response to Question Nos. 85-89. At a minimum, the Commission should reaffirm its current requirement that applicants for transmission rate incentives propose metrics for expected project benefits.[102]

3. Incentives Based on Project Characteristics

Q 12) How, if at all, would examining transmission projects' characteristics in evaluations of transmission incentives applications improve the Commission's transmission incentives policy and achieve the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework? Would this approach result in different outcomes, as compared to the current risks and challenges approach for granting incentives?

Q 13) If the Commission adopts an approach based on project characteristics, should it lay out general principles and/or bright line criteria for identifying or evaluating those characteristics?

Q 14) If so, how should applicable criteria be established, and, in cases where more than one criterion applies, how should they be evaluated in combination?

Q 15) How would an approach based on project characteristics impact certainty for project developers, particularly relative to the current risks and challenges framework?

The Commission suggests that project characteristics could serve "as a proxy for expected benefits"[103] in considering requests for incentives. Thus, the project characteristics framework would resemble an "expected benefits" approach, and, in Joint Commenters' view, would suffer from most, if not all, of the same problems. In particular, a project characteristics framework would improperly jettison the requirement to show that requested incentives are designed to address project risks and challenges. A project characteristics approach could be

[102] *See* Order No. 679-A at P 128.

[103] Incentive NOI at P 18.

even *more* problematic than an expected benefits approach to the extent it awards incentives based merely on certain features of the project as a "proxy" for benefits rather than requiring a showing of specific project benefits. Accordingly, Joint Commenters do not support adoption of a "project characteristics" framework for evaluating benefits. If the Commission were to implement such an approach, the same requirements and parameters described above for the "expected benefits" approach should apply. As with the discussion of the expected benefits approach above, Joint Commenters address several aspects of the Commission's questions in an effort to be responsive.

The Incentive NOI cites several examples of the kind of project characteristics that might merit incentives, including "transmission projects located in regions with persistent needs, interregional transmissions projects, or transmission projects that unlock constrained resources."[104] The NOI also references projects that include "specific transmission technologies."[105] Joint Commenters do not dispute that projects with these characteristics generally can be beneficial to transmission customers. Joint Commenters do dispute the notions, however, that the current "risks and challenge" framework is an obstacle to pursuit of these projects, and that changing the framework for evaluating transmission incentives would result in more of them being built. The Commission has already said that projects with the characteristics described above might warrant incentives – including incentive ROE adders – under the risks and challenges framework, so lack of opportunity to seek incentives should not be an impediment for these types of projects.[106]

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[104] *Id.*

[105] *Id.*

[106] *See* 2012 Policy Statement at P 21.

Properly functioning local, regional, and interregional transmission planning processes, moreover, should already identify projects with the characteristics cited in the NOI without any need for incentives. For example, if transmission projects are warranted in regions with persistent needs, the regional transmission planning process should be addressing those needs. Indeed, a finding that transmission needs in some regions remain "persistent" would suggest either a problem with the planning process itself, or the existence of other obstacles to building necessary grid infrastructure that cannot be solved through the Commission's incentives policy.

Joint Commenters are not aware of any evidence to suggest that any lack of transmission projects with beneficial characteristics is attributable to the Commission's incentives rules. For example, the Commission's list of project characteristics that might warrant incentives includes "interregional transmission projects."[107] While Joint Commenters submit that it remains too early to judge whether there has been a lack of appropriate interregional project development, any perceived lack of interregional projects since Order No. 1000 was implemented likely has less to do with the Commission's incentive rules and more to do with the relative needs of a particular set of regions or the requirements for planning and cost allocation for interregional projects under the rules adopted in various regions.[108] To the extent regions can demonstrate that cost effective and efficient transmission projects are not being built to resolve transmission needs, and they believe procedural or substantive improvements are needed in those rules, they should be encouraged to first determine solutions in partnership with their neighbors and stakeholders.

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[107] Incentive NOI at P 18.

[108] *Cf. Northern Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,058 (2016), *order on reh'g,* 158 FERC ¶ 61,049 (2017) (addressing complaint challenging aspects of the interregional planning process and cost allocation as between MISO and PJM).

Certain challenges to construction of new transmission simply fall outside of the Commission's jurisdiction. Large interregional projects and projects to unlock constrained resources may face particularly difficult siting challenges. The FPA leaves transmission siting authority to state and local officials, and it is unlikely that incentives for transmission developers can have any influence on the underlying siting decisions. Granting incentives to project developers – particularly return-enhancing incentives – might be counterproductive because it may increase resistance to the allocation of project costs. The Commission's existing transmission incentive rules and policies already provide appropriate opportunities to obtain risk-reducing incentives to address project siting risks, and providing an overgenerous package of risk-reducing and return-enhancing incentives certainly does nothing to address the underlying issue.

Further, any dearth of new projects with beneficial characteristics may be partially attributable to the fact that, in some RTO/ISO regions, many transmission projects do not go through the full RTO/ISO planning process or even a local planning process that is required to comply with Order No. 890 local planning requirements.[109] The Brattle Group reports that almost half (47 percent) of transmission investment in RTO/ISO regions during 2013 to 2017 was not subject to a full RTO/ISO planning process with associated stakeholder review.[110] Concerns about the elevated investment level in these local projects and the relatively limited opportunity for stakeholder review have been raised, in particular, in PJM and CAISO.[111]

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[109] *See Cal. Pub. Utils. Comm'n v. Pacific Gas & Elec. Co.*, 164 FERC ¶ 61,161; *Monongahela Power Co.*, 162 FERC ¶ 61,129*, reh'g denied*, 164 FERC 61,217.

[110] Brattle Report at 24-25.

[111] *See Cal. Pub. Util. Comm'n v. Pacific Gas and Elec. Co.*, Complaint, Docket No. EL17-45 at 4-5 & n. 7 (noting that more than 60 percent of the capital expenses by Pacific Gas and Electric Company ("PG&E") for 2014, 2015, and 2016 were for self-approved projects and that "of PG&E's $2.5 billion in forecast capital electric transmission

Transmission owners' investment focus on these projects, as well as the lack of a requirement to incorporate the planning for these projects in the broader RTO/ISO regional planning process, may result in missed opportunities for investment in more regionally-beneficial infrastructure.

Q 16) Should transmission projects with certain characteristics be awarded incentives automatically? How could the Commission administer such an approach?

For the reasons provided in response to Question No. 7 above, automatically awarding incentives based on project characteristics would not be appropriate.

B. Particular Incentive Objectives

The NOI identifies twelve potential "incentive objectives," and "seeks comment on what the Commission should incentivize in order to satisfy Congress's directives in section 219."[112] The Commission requests comment, in particular, "on what expected benefits or project characteristics warrant incentives."[113] As discussed above, Joint Commenters do not support a shift away from the Commission's current framework for evaluating project-specific incentive requests toward one that focuses exclusively on granting incentives for particular project benefits or characteristics. Joint Commenters do not believe that such a change in the Commission's framework is either necessary or legally sound.

This is not to say that the twelve incentive objectives listed in the NOI cannot or should not be incorporated into the Commission's current framework for considering applications for project-specific incentives. If a project, by virtue of providing one or more of the listed benefits or characteristics (*e.g.*, improving reliability or unlocking constrained resources), is able to "benefit[] consumers by ensuring reliability and reducing the cost of delivered power by

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expenditures for 2016 and 2017, a full $1.5 billion is attributable to capital investments that do not undergo any external review.") (internal footnotes omitted).

[112] Incentive NOI at P 20.

[113] *Id.*

reducing transmission congestion,"[114] then the characteristics can be considered under the Commission's current framework for evaluating incentive applications. Such benefits and characteristics might be particularly relevant if the project is not entitled to the rebuttable presumption of project benefit under 18 C.F.R. § 35.35(i) (2019) or the Commission does not adopt Joint Commenters' position that approval in a regional transmission planning process should be a prerequisite for incentives. Further, as discussed in response to Question Nos. 50 and 51. Joint Commenters believe the Commission should retain but enhance its current approach to promoting joint ownership through its transmission incentive policies.

In general, however, Joint Commenters do not support changes to the Commission's rules and policies to focus on particular "incentive objectives." We address certain of the NOI's questions on these specific objectives below.

1. Reliability Benefits

Q 17) Should the Commission tailor incentives to promote these types of projects based on their expected reliability benefits? If so, how should the Commission differentiate these projects from others required to meet reliability standards?

Q 18) Are there specific reliability benefits or project characteristics that could merit such an approach?

Q 19) If the Commission tailored incentives for reliability benefits, how should the Commission measure the expected enhancement to transmission reliability? Should there be a threshold or bright line test applied? If so, how?

Q 20) Should the Commission incentivize transmission facilities that expand access to essential reliability services, such as frequency support, ramping capability, and voltage support?

Q 21) If so, how should the Commission assess and measure whether transmission projects expand access to essential reliability services?

[114] 16 U.S.C. § 824s(a).

As the NOI acknowledges, transmission providers are already subject to mandatory North American Electric Reliability Corporation ("NERC") standards and other planning criteria intended to help ensure the reliable operation of the transmission system.[115] Awarding incentives for complying with such requirements is inappropriate.[116] Further, there is very little risk that transmission providers will be unable to recover the costs of investments needed to comply with NERC standards or other system planning criteria. Accordingly, there should be no need for incentives to prompt transmission providers or developers to undertake such investments.[117]

Joint Commenters do not believe, moreover, that incentives are necessary or appropriate "to promote reliability transmission projects that significantly enhance transmission reliability above and beyond what is required by the NERC reliability standards or other planning criteria."[118] *First*, it is not at all clear why the Commission would want to adopt a policy that encourages transmission investment for a level of reliability significantly "above and beyond" what the NERC standards and other planning requirements dictate. These planning criteria are aimed at providing an adequate level of reliability, and simply providing "more" reliability is not necessarily beneficial or cost-effective for consumers. As Joint Commenters explained above, it likely would be difficult and contentious to quantify the enhanced reliability benefits provided by projects receiving incentives. *Second*, a framework that, by design, aims to promote projects that might not ordinarily result from a local or regional transmission planning process would likely lead to conflicts with the planning process, as discussed above. Gold-plating also would be a

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[115] Incentive NOI at P 22.

[116] *See, e.g.*, *CPUC v. FERC*, 879 F.3d at 978.

[117] Indeed, the Commission's regulations provide that "[t]he Commission *will approve recovery* of prudently-incurred costs necessary to comply with the mandatory reliability standards pursuant to section 215 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential." 18 C.F.R. § 35.35(f) (2019).

[118] Incentive NOI at P 22.

significant concern. *Finally*, in circumstances where it is reasonable to invest in transmission facilities to promote a level of reliability beyond what is required by the NERC standards or other planning criteria, it is unlikely that transmission providers will be unable to recover the costs of such an investment. This point was made clear, for instance, at the recent joint technical conference with the Department of Energy ("DOE") on infrastructure security investment.[119] Given this lack of cost-recovery risk and the other reasons cited above, it would be inappropriate to provide incentives for transmission investment beyond what is required to apply with applicable reliability and planning standards, even in situations where such investments might be warranted.

2. Economic Efficiency Benefits

Q 22) Should the Commission tailor incentives to promote projects that accomplish the outcomes of reducing congestion or facilitating access to additional generation?

Q 23) Should the Commission establish bright line metrics, such as a specified level of reduction in average production costs, to determine whether a transmission project merits incentives?

Q 24) Should the Commission consider incentivizing transmission projects that are scaled to more efficiently facilitate interconnection of, or transmission to, additional generation? What other measurable economic efficiency benefits should be considered a bright line metric for the purposes of economic efficiency?

Q 25) How should the applicable bright line criteria be established, and, in cases where more than one criterion applies, how should they be evaluated in combination?

Joint Commenters do not support changes to the Commission's rules or policies to provide incentives specifically tailored to promote economic efficiency benefits. Section 219 of the FPA and the Commission's regulations already provide for incentives for economic

[119] *See Security Investments for Energy Infrastructure Tech. Conf.*, Docket No. AD19-12-000, Technical Conference Transcript (March 28, 2019) ("Tr.") at 48, 78 (Akins); Tr. at 64 (Santa); Tr. at 121, 151 (Crane); Tr. at 130-31, 151-52, 161-62 (Emler); Tr. at 137-38, 152 (Kjellander); Tr. at 152, 160-61 (Chivukula); *see also Security Investments for Energy Infrastructure Tech. Conf.*, Docket No. AD19-12-000, Written Statement of Kevin G. Wailes at 6-7 (March 26, 2019) ("Wailes Statement").

efficiency benefits, inasmuch as eligible projects specifically include those that "reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219."[120] Further, many of the RTO/ISO transmission planning processes encompass planning for economic projects,[121] and any Order No. 1000-compliant regional planning process should be identifying the "more efficient or cost-effective investments" to address planning needs. To the extent the Commission is concerned these planning processes fail to produce an appropriate number of projects that provide economic efficiency benefits or that facilitate access to additional generation, a better alternative would be to encourage transmission providers first to identify the planning process causes and determine solutions in partnership with their neighbors and stakeholders.

3. Persistent Geographic Needs

Q 26) Should the Commission utilize an incentives approach that is based on targeting certain geographic areas where transmission projects would enhance reliability and/or have particular economic efficiency benefits? If so, how should the relevant geographic areas be identified and defined? What entity (e.g., the Commission, RTOs/ISOs, state regulators, other stakeholders) should designate such areas?

Q 27) What criteria should be used to define such geographic areas? Procedurally, how should such geographic areas be determined, monitored, and updated?

Q 27) What criteria should be used to define such geographic areas? Procedurally, how should such geographic areas be determined, monitored, and updated?

Q 28) Should the relevant geographic areas be defined on an ex ante basis and/or should the transmission developer have the burden of demonstrating that the relevant transmission project falls within a geographic region that has an acute need for transmission?

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[120] 18 C.F.R. §35.35(d) (2019).

[121] *See, e.g.*, CAISO Open Access Transmission Tariff, § 24.4.6.7; ISO-NE Open Access Transmission Tariff, Attachment N, § II.B; NYISO Open Access Transmission Tariff, Att. Y, § 31.3; PJM Amended and Restated Operating Agreement, Sch. 6, § 1.5.7; SPP Open Access Transmission Tariff, Att. O, § III.

Joint Commenters agree there may be specific geographic areas that could particularly benefit from new or upgraded transmission infrastructure. If the local, regional, and interregional transmission planning processes required by Order Nos. 1000 and 890 are being conducted properly, however, geographic areas where there is "an acute need for transmission" facilities to enhance reliability or provide economic benefits should be readily identifiable to the transmission provider and to stakeholders, who should plan a system expansion or enhancement to address the need. Again, there is no reason to think that transmission providers or developers would be unwilling to invest in such a project and recover the costs, including a reasonable return, through Commission-regulated rates.

If a solution for such a "persistent geographic need" is not being implemented, that suggests either a limitation in the planning process itself or some other hurdle. Indeed, the fact that a need becomes "acute" or "persistent" in the first place would indicate a systemic obstacle(s) to a transmission (or non-transmission) solution that incentives would not overcome. By the same token, if the transmission need is "acute," then it is not reasonable to impose the additional costs or risks of project incentives on customers for a project that the transmission provider plainly should be willing to undertake.

4. Flexible Transmission System Operation

Q 29) How can flexibility characteristics improve the operation of the transmission system?

Q 30) Should the Commission incentivize flexibility characteristics and, if so, how should it do so?

Q 31) How could the Commission define "flexibility" in this context?

As with other "incentive objectives," Joint Commenters reiterate that properly functioning transmission planning processes under Order Nos. 1000 and 890, including consideration of non-transmission alternatives, should be sufficient to identify and adopt

transmission facilities that provide for flexible system operation without the need for incentives. Trying to define and measure flexibility benefits to evaluate incentive proposals also would likely be contentious.

5. Security

Q 32) Should the Commission incentivize physical and cyber-security enhancements at transmission facilities? If so, what types of security investments should qualify for transmission incentives? What type of incentive(s) would be appropriate?

Q 33) How should the Commission define "security" in the context of determining eligibility for incentive treatment? For example, should the Commission define security based on specific investments or based on performance of delivering increased security of the transmission system?

Ensuring the reliability and security of the transmission system is a fundamental obligation of transmission providers, which must comply with mandatory NERC reliability standards and good utility practice. These standards also guide regional and local transmission planning requirements. Awarding public utilities incentives for investments necessary to comply with mandatory reliability standards and prudent transmission planning requirements would be inconsistent with the bedrock principle that incentives should not be granted to promote actions that a utility is already compelled to take.[122]

One of the consistent themes at the Commission's recent joint technical conference with the DOE on infrastructure security investment was that public utility transmission providers have not faced significant obstacles in recovering through FERC-approved rates prudent investments designed to promote infrastructure security, even for projects that may go beyond the requirements of NERC's mandatory reliability standards. The general consensus among the technical conference panelists was that appropriate infrastructure security investments have not

[122] *See, e.g.*, *CPUC v. FERC*, 879 F.3d at 978. Section 215A of the FPA, moreover, addresses recovery of costs incurred in connection with declared grid security emergencies. 16 U.S.C. § 824o-1.

been hindered by cost recovery obstacles at either the federal or state levels.[123] Christopher Crane, CEO of Exelon Corporation, made this point explicitly, stating that "[w]e have not, at Exelon, our 6 utilities have not experienced any issues with recovery on the prudent investments around the physical and cybersecurity."[124] Nick Akins, CEO of American Electric Power, observed that "typically we won't get disallowed a cost associated with resiliency and reliability of the grid and that's really probably one of our least risky investments we can make."[125] Chairman Chatterjee stated in this regard that "[s]ince the events of September 11th, I think this Commission has been very accommodating in providing a number of mechanisms for utilities to recover the costs of their prudently incurred security expenditures."[126] Indeed, Commissioner Glick observed that the "headline" from the technical conference was that "cost recovery at the state or federal level really isn't a barrier to utilities doing what they need to do to protect . . . from physical or cyberattacks . . . ."[127]

Given the obligations of transmission providers to maintain a secure and reliable system, and the lack of cost-recovery risk for investments needed to do so, there is no need for incentives under FPA section 219 to promote physical and cyber-security enhancements for transmission facilities.[128] There were few such calls at the FERC-DOE technical conference for new or

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[123] *See, e.g.*, Wailes Statement at 6-7; Tr. at 48, 78 (Akins); Tr. at 64 (Santa); Tr. at 121, 151 (Crane); Tr. at 130-31, 151-52, 161-62 (Emler); Tr. at 137-38, 152 (Kjellander); Tr. at 152, 160-61 (Chivukula).

[124] Tr. at 151 (Crane). Mr. Crane later noted that some Exelon utilities had experienced instances of regulatory lag. *See* Tr. at 197-98.

[125] Tr. at 78 (Akins).

[126] Tr. at 151.

[127] Tr. at 187 (Comm'r Glick).

[128] *See, e.g.*, *Security Investments for Energy Infrastructure Tech. Conf.*, Docket No. AD19-12-000, Post-Technical Conference Comments of the American Public Power Association at 4-7 (May 28, 2019); *Security Investments for Energy Infrastructure Tech. Conf.*, Docket No. AD19-12-000, Post-Technical Conference Comments of the Electricity Consumers Resource Council at 15-16 (May 28, 2019); *Security Investments for Energy Infrastructure Tech. Conf.*, Docket No. AD19-12-000, Post-Technical Conference Comments of the Transmission Access Policy Study Group at 5-8 (May 28, 2019).

revised incentives to promote infrastructure security.[129] Mr. Crane of Exelon was clear on this point as well: "[i]t is our belief that the electric industry doesn't need a new set of incentives to continue investing in critical infrastructure."[130]

The absence of appeals for broad new incentives or cost recovery mechanisms to support infrastructure security investment is wholly understandable. As Lincoln Electric System CEO Kevin Wailes observed in his statement for the FERC-DOE technical conference, "[p]ublic utilities already have numerous financial, legal, and reputational incentives to promote physical and cybersecurity,"[131] and the discussion at the technical conference made clear that electric and gas utilities are not waiting for incentives to focus on cyber and physical security.[132] Adopting special rate incentives or cost recovery mechanisms for particular types of infrastructure investments could also have unintended consequences. As Mr. Wailes observed, "rate incentives could influence utilities to focus on infrastructure investments that are eligible for incentives, which might not necessarily be the soundest risk mitigation or recovery approach in a given situation."[133]

Attempting to define the types of investments which might be eligible for a "security enhancement" incentive would be difficult and subjective, particularly for investments that may go beyond the measures required by mandatory reliability standards. Measuring performance of

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[129] A number of panelists suggested discrete practices that the Commission might consider promoting through incentives. *See* Tr. at 116 (Robb); Tr. at 117 (Galloway); Tr. at 119 (Evanina). Mr. Akins appeared to endorse a broader generic incentive, suggesting a "transmission-related resiliency incentive mechanism." Tr. at 115 (Akins).

[130] Tr. at 121 (Crane).

[131] Wailes Statement at 7; *see also* Tr. at 66 (Akins) (explaining that "it goes to operational excellence and if your brand is built around operational excellence and you see it as a really something that can really diminish the brand, there's nothing worse that could happen to a company in our opinion to have a significant outage caused by any event, but let alone a cyber event.").

[132] *See, e.g.*, Tr. at 47 (Akins); Tr. at 80 (Santa); Tr. at 137 (Wailes); Tr. at 143-45 (Armstrong).

[133] *Id.*

increased security is nearly impossible, especially when targeting the prevention of exceptionally rare "fat tail" events for which statistical samples are insufficient to draw conclusions to gauge performance. The difficulty in quantifying increases in "security" would make it difficult, if not impossible, to calibrate incentives to promote this benefit.

Joint Commenters support efforts to ensure the physical and cyber security of the grid, but transmission incentives are not the way to accomplish this goal. To encourage improved security investments and practices, the Commission might, for example, focus on removing administrative barriers to adoption of best practices and ensuring that market participants' incentives align with bulk system reliability. One consistent message on this score from the FERC-DOE technical conference was that access to reliable threat information can play an important role in promoting appropriate investment and best practices to promote cyber and physical security.[134] Mr. Wailes explained that, in considering infrastructure security investments, utilities must weigh the risks against the potential cost constraints on security investments, and having dependable threat awareness and information about how to mitigate those threats can promote an appropriate level of investment.[135] Facilitating appropriate access to threat information can avoid cost recovery disputes by reassuring "regulators and utility customers that costs are being prudently-incurred and that rates reflect the reasonable costs of providing safe and reliable service."[136] Other technical conference panelists echoed this point.[137]

6. Resilience

Q 34) Should transmission projects that enhance resilience be eligible for incentives based upon their reliability-enhancing attributes?

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[134] Tr. at 134, 204-05; *see also* Wailes Statement at 3.

[135] *See* Tr. at 134, 204-05 (Wailes).

[136] Wailes Statement at 3.

[137] *See, e.g.*, Tr. at 38-39 (Evanina); Tr. at 55-58 (Robb); Tr. at 63, 65, 96 (Santa); Tr. at 72-73 (Gabriel); Tr. at 92 (Kosak); Tr. at 131-32 (Emler); Tr. at 145-46, 167-68, 201 (Armstrong); Tr. at 147-48 (Chivukula).

Q 35) If so, how could the Commission consider or measure the benefits of an individual project towards grid resilience?

Q 36) If the Commission were to grant incentives for measures that enhance the resilience of the transmission system, what incentive(s) would be appropriate?

Joint Commenters do not support incentives aimed at enhancing "resilience." As the still-pending proceedings in Docket No. AD18-17-000 indicate, there are a wide variety of views on what "resilience" means in different contexts,[138] the best ways to promote it, the extent to which the concept should be – or already is – incorporated into planning requirements, and what, if anything, the Commission can and should do to help ensure a resilient grid. Given the unsettled nature of many of these issues at the Commission, it would be, at best, premature to adopt any policy to encourage resilience through incentives.

As with other "incentive objectives," any benefits associated with enhanced resilience should be addressed in the transmission planning process, not through incentives policy. Projects that enhance reliability by increasing resilience, if necessary, should be identified and planned in a regional or local transmission planning process that complies with Order Nos. 1000 and/or 890 and takes into account regional needs. In considering whether action is required to promote system resilience, the regional planning process can identify particular risks or scenarios that stakeholders are seeking to guard against. If action is shown to be justified, reasonable and cost-effective solutions should be developed. As with reliability and security discussed above, there is little reason to think that transmission providers and developers would face material cost

[138] The Commission has suggested that resilience may be characterized generally as "[t]he 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." *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at P 23 (2018) (footnote omitted). While it is relatively straightforward to describe resilience conceptually, it is more challenging to determine what actions, if any, might be appropriate for the Commission to take to promote resilience. The definition, by itself, does not describe the particular "disruptive events" that should be addressed, nor does it identify the actions that might be taken to help ensure grid resilience.

recovery risk for such infrastructure, or that they would need incentives to undertake these projects. To the extent incentives are warranted, risk-reducing incentives should be sufficient to promote most projects.

7. Improving Existing Transmission Facilities

Q 37) How should the Commission incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid? How can the Commission identify and quantify how a technology or other measure contributes to those goals? Please provide examples.

Q 38) Can the Commission distinguish between incremental improvements that merit an incentive and those maintenance-related expenses that a transmission owner would make in its ordinary course of business?

Q 39) How should a transmission owner seeking this type of incentive demonstrate increases or improvements in the capabilities or operations of existing transmission facilities?

Q 40) Should the Commission provide a stand-alone, transmission technology-related incentive? If the Commission provides a stand-alone transmission technology-related incentive, what criteria should be employed for a technology to be considered as meriting an incentive? Should the Commission periodically revisit the definition of an eligible technology?

Q 41) Certain utility costs, such as those associated with grid management technology, including dynamic line rating technology, are typically recovered through operations and maintenance expenses within cost-of service rates. For such costs, should the Commission, instead, consider inclusion of these expenses in rate base as a regulatory asset? If so, what costs should be eligible for such treatment and over what period should they be amortized?

Q 42) Are there ways the Commission could incentivize RTOs/ISOs to adopt better grid management technologies and/or other technologies to improve the efficiency of individual transmission assets to promote efficient use of the transmission system and improved market performance?

Q 43) Should the Commission interpret section 219(b)(3) to encourage improvements that are not historically considered part of the transmission system, such as, for example, software upgrades, technologies that allow for faster ramping, or other innovative measures that achieve the same goals as new transmission facilities? What types of incentives could increase the adoption of these technologies? Are there forms of performance-based ratemaking with respect to transmission that the Commission should explore? If so, describe such alternative ratemaking structures.

Joint Commenters support the use of innovative technologies that can enhance the capacity, efficiency, and operation of the transmission grid. We question, however, why this should be a matter for the Commission's incentive policy. An open, transparent, and coordinated regional planning process should be able to identify the more efficient or cost-effective investments to address the needs of the transmission grid. Even if innovative technologies that can address regional planning needs are not traditional transmission solutions, the Commission specified in Order No. 1000 that transmission providers are required to consider transmission and non-transmission alternatives on a comparable basis.[139]

To the extent that the Commission wishes to encourage the deployment of technologies and other measures through its transmission incentive policies, it could consider doing so by reiterating the policy that transmission providers and developers are obliged to mitigate risk by considering alternatives before seeking an incentive ROE.[140] In its 2012 Policy Statement, the Commission stated that it expected "applicants for an incentive ROE based on a project's risks and challenges to demonstrate that alternatives to the project have been, or will be, considered in either a relevant transmission planning process or another appropriate forum."[141] The Commission could strengthen this position, by specifying that applicants for a return-enhancing incentive must show that they considered innovative technologies and other measures to reduce scope and/or risk of a proposed project before seeking a project-specific ROE adder.

8. Interregional Transmission Projects

Q 44) Should the Commission use incentives to encourage the development of interregional transmission projects? How, if at all, would any such incentive interact with Order No. 1000's reforms?

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[139] *See* Order No. 1000 at P 148.

[140] *See* 2012 Policy Statement at P 25.

[141] *Id.*

Q 45) If the Commission should use incentives to encourage interregional transmission projects, should all interregional projects be eligible or should it be based on some other criteria? How should the Commission consider the benefits of an individual interregional transmission project?

Q 46) If the Commission were to grant incentives for interregional transmission projects, what incentive(s) would be appropriate?

The Commission should not adopt incentives specifically directed at encouraging interregional transmission projects. As with other incentive objectives discussed above, properly functioning transmission planning processes under Order Nos. 1000 and 890 should be sufficient to identify and plan interregional projects. While, as discussed above, it remains too early to judge whether there has been a lack of appropriate interregional project development, any perceived lack of interregional projects since Order No. 1000 was implemented likely has less to do with the Commission's incentive rules and more to do with the requirements for planning and cost allocation for interregional projects under the rules adopted in various regions. To the extent regions believe procedural or substantive improvements are needed in those rules, they should be encouraged to first determine solutions in partnership with their neighbors and stakeholders.

9. Unlocking Locationally Constrained Resources

Q 47) Should the Commission use incentives to encourage the development of transmission projects that will facilitate the interconnection of large amounts of resources?

Q 48) If so, what metrics could the Commission consider when evaluating whether a transmission project facilitates the interconnection of generation?

Q 49) Should such an incentive focus on resources already in the queue, a region's potential for new resources, or some other measure? How could the Commission evaluate the potential for further resource development in a particular geographic area?

Properly functioning transmission planning processes under Order Nos. 1000 and 890 should be sufficient to identify and plan transmission facilities that unlock locationally-

constrained resources when it is cost-effective to do so. Incentives specifically directed at promoting such transmission projects should be unnecessary and may even be counterproductive to the extent that pursuit of incentives interferes with the regional transmission planning process, as discussed above.

10. Ownership by Non-Public Utilities

Q 50) Are there barriers to non-public utilities' ownership of transmission facilities?

There are certain general barriers to transmission development and ownership by non-public utilities, including the relatively small size of many non-public utilities,[142] the cost and complexities of participating in RTO/ISO or other regional transmission planning processes, and legal and practical advantages of incumbent public utility transmission providers in many regions. These hurdles are, by no means, insurmountable. Many larger non-public utilities own and operate significant transmission assets, and smaller utilities have formed public power joint action agencies or generation and transmission cooperatives to invest in transmission assets.

A key way of accommodating ownership of transmission assets by non-public utilities is through joint ownership arrangements. The Commission has consistently recognized the benefits of joint ownership of transmission facilities, and, in particular, has encouraged the participation of non-public utilities in jointly owned projects.[143] The Commission stated in Order No. 890, that it "believes there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission

[142] Statistics maintained by the American Public Power Association show that 1,684 of the nation's approximately 2,000 public power utilities serve fewer than 10,000 customers (meters), and 1,352 public power utilities serve fewer than 4,000 customers. *Available at:* https://www.publicpower.org/public-power/stats-and-facts.

[143] An overview of the benefits associated with joint ownership can be found in the 2012 policy paper on the subject issued by the Transmission Access Policy Study Group ("TAPS"), *available at*: https://tapsgroup.org/wp-content/uploads/2013/01/TAPS-Joint-Ownership-White-Paper.pdf.

customers."[144] The Commission reiterated these points in Order No. 1000.[145] In a period of rising transmission costs, moreover, joint ownership of transmission facilities can effectively provide a hedge against these costs. The Commission's belief in the benefits of joint ownership is well justified, as successful joint ownership initiatives such as CapX2020 in the Upper Midwest illustrate.[146]

Encouraging joint ownership by non-public utilities has been a feature of the Commission's FPA section 219 transmission incentive policies since Order No. 679.[147] In Order No. 679-A, the Commission stated that it "encourages public power participation," explaining that it would "look favorably on an incentive request that includes public power joint ownership."[148] In updating its incentives policy in 2012, the Commission observed that joint ownership arrangements can "mitigate risks associated with siting and environmental impacts."[149] Under the 2012 Policy Statement, "[t]he Commission encourages incentives applicants to participate in joint ownership arrangements and agrees . . . that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks."[150] The Commission's encouragement for joint ownership by non-public utilities comports

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[144] Order No. 890 at P 593.

[145] Order No. 1000 at P 776; *see also* Order No. 1000-A at P 81 (stating that "the Commission supports investment in transmission by transmission dependent utilities . . . .").

[146] CapX2020 is a joint initiative of eleven utilities, including non-public utilities, that was formed to upgrade and expand the electric transmission grid in the Upper Midwest. *See generally Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,171, at P 3 (2014). CapX2020 has been characterized as "a great example of how joint ownership in the upper Midwest can harness the collaboration of eleven utilities, their regulators and the public to expand the transmission grid to meet increased demand and support renewable energy development." *WPPI Energy*, 141 FERC ¶ 61,004, at p. 61,014 (2012) (Comm'r Norris, concurring). Additional information regarding the CapX2020 initiative is available at: http://www.capx2020.com.

[147] *See* Order No. 679 at PP 354, 357.

[148] Order No. 679-A at P 102.

[149] 2012 Policy Statement at P 24.

[150] *Id.*

with the admonition in FPA section 219(b)(1) that the Commission's rules should promote beneficial transmission investment "regardless of the ownership of the facilities."[151]

Despite the benefits of joint ownership and the Commission's longstanding encouragement of such arrangements, participation by non-public utilities in joint ownership arrangements has remained relatively limited in certain regions. There are areas of the country in which joint ownership is common, but it is the exception rather than the rule in others. While it can be difficult to identify with particularity why more joint ownership opportunities have not materialized, Joint Commenters note that incumbent public utility transmission providers generally lack the incentive to turn over a portion of project rate base (and the associated allowed returns) to non-public utilities. Other limiting factors on joint ownership opportunities likely include the growth of projects that do not go through the full RTO/ISO planning process and the relatively small number of competitive projects under Order No. 1000, which could provide joint-ownership opportunities.

Q 51) Should the Commission consider granting incentives to promote joint ownership arrangements with non-public utilities and, if so, how?

Joint Commenters do not believe it is necessary or appropriate to grant new or additional incentives to promote joint ownership arrangements for non-public utilities. Rather, to help encourage expanded joint ownership opportunities, the Commission should retain and enhance its current approach to promoting joint ownership through its transmission incentive policies.

As explained above, Joint Commenters believe the Commission should retain its current framework for evaluating project-specific transmission incentive applications, under which consideration of joint ownership arrangements is among the risk mitigation measures that an

[151] 16 U.S.C. § 824s(b)(1).

applicant may demonstrate before seeking an incentive ROE.[152] The Commission should retain this general approach in enhanced form. Specifically, Joint Commenters recommend that the Commission require each applicant for project-specific transmission incentives to explain whether opportunities for joint ownership in the project were offered to non-public utilities within the project sponsor's service footprint that will bear a portion of the project cost, and, if not, why not. Each applicant should be required to explain why joint ownership either was infeasible or would not mitigate the risks associated with the development of a project. Any project for which joint ownership arrangements may have been feasible but were not pursued should face heightened scrutiny in seeking incentives, particularly return-enhancing incentives. Close scrutiny of an applicant's consideration of joint ownership arrangements should be given to large projects where the applicant attempts to justify incentive rate treatment based on the magnitude of the risk of adding facilities that are large in proportion to its existing transmission plant.

11. Order No. 1000 Transmission Projects

In the NOI, the Commission notes that it "has considered whether it could reduce transmission developer risk by granting blanket pre-approval (*i.e.*, a rebuttable presumption) of three risk-reducing incentives for transmission projects selected in a regional transmission plan for purpose of cost allocation: CWIP, abandoned plant, and regulatory asset treatment."[153] The Commission poses two questions on this point, which Joint Commenters address below.

> *Q 52) Should these or other incentives be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation?*

[152] 2012 Policy Statement at P 24.

[153] Incentive NOI at P 33 (citing *Notice Inviting Post-Technical Conference Comments*, Docket No. AD16-18-000, at 2 (Aug. 3, 2016)).

The Commission should not grant blanket pre-approval (i.e., a rebuttable presumption) or otherwise automatically award incentives for transmission projects selected in a regional transmission plan for purposes of cost allocation. Instead, the Commission should continue to require case-by-case evaluation of requested incentives, including for risk-reducing incentives such as CWIP, abandoned plant or regulatory asset treatment. Contrary to FPA section 219's purpose of benefitting consumers, pre-approving or automatically granting incentives, even where the transmission project was selected in a regional transmission plan for purposes of cost allocation, would negatively impact consumers in several respects.

First, project selection under a Commission-approved regional planning process is a relevant, but not sufficient, condition for approval of incentives. Selection of a project in a regional transmission planning process does not obviate examination of pertinent factors such as the risks and challenges faced by the applicant in determining if the applicant merits pre-approval of any incentives for the project.[154] In fact, the Commission has found that not all transmission projects that are selected in a regional transmission planning process merit a transmission incentive. For instance, there have been cases where the Commission has determined that applicants, whose projects had been approved in regional transmission planning processes, failed to demonstrate that the abandoned plant incentive was tailored to address the demonstrable risks and challenges.[155] In addition, while the Commission has routinely granted

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[154] *See Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana, Inc.*, 124 FERC ¶ 61,231, at P 18 (2008) (finding that while "PJM's scrutiny of baseline projects is *significant* in our analysis of whether a project has met the nexus test," this "does not mean that all baseline projects in PJM's RTEP will qualify automatically for incentives under Order No. 679," and stating the Commission also examines factors such as "the scope of the project, its effect on the transmission system, and other challenges or risks faced by the project.") (emphasis in original).

[155] *See, e.g.*, *Pacific Gas and Elec. Co.*, 160 FERC ¶ 61,018 (2017) (finding five of the eight projects selected in a regional transmission plan and that were subject of the application did not merit the abandoned plant incentive because they either presented limited, speculative or modest risks or challenges, and one project largely involved upgrades and extensions of existing facilities); *PJM Interconnection, L.L.C. and Commonwealth Edison Co.*, 155 FERC ¶ 61,304, at P 24 (2016) (finding that the only risk cited in support of the abandoned plant incentive related to

the CWIP incentive where Order No. 679 applicants with specific projects request it,[156] the Commission has also recognized the importance of understanding the details of an applicant's financial situation and the size of the investment in determining whether a CWIP incentive is warranted.[157] As such, the pre-approval or automatic grant of incentives without a test for determining whether such an incentive is needed or will benefit customers is inconsistent with section 219 and will dilute the consumer protection principles of the FPA.[158]

Second, pre-approving or automatically granting transmission incentives to projects that have been selected in a regional transmission planning process would result in an undue shift in the burden of demonstrating ineligibility, unreasonableness, or imprudence to consumers.[159] Pre-approval or automatic grant may also deprive the Commission and stakeholders of project-specific information pertaining to the application, which would make it difficult for consumers to

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pendency of a protest in another proceeding, and because the risk that the transmission planning region could discontinue its selection of a project in the regional transmission plan is not a project-specific risk, but is instead faced by every entity developing a transmission facility in PJM).

[156] *See, e.g., Baltimore Gas & Elec. Co.,* 120 FERC ¶ 61,084, at P 70 (2007) (rejecting an applicant's request for a permanent 100 percent CWIP revision in its formula rate on the grounds that the "Commission's regulations provide CWIP only for specific projects, not the blanket approval sought here."); *Transource Wisconsin, LLC*, 149 FERC ¶ 61,180, at P 29 (2014) (noting that incumbent transmission owners do not already have the advantage of the CWIP incentive and, like nonincumbent transmission developers, request it after a specific project is identified).

[157] *See ATX Southwest, LLC*, 152 FERC ¶ 61,193, at P 48 (2015) (finding that the applicant had not met the nexus test under Order No. 679, in part, because it failed to describe details of its financial situation that CWIP would alleviate, including details regarding its financial pressures, delayed cash flow, relative size of its investment, any adverse impacts to short-term liquidity, or the size of the effect on cash flow that CWIP would elicit); Order No. 679 at P 117 (finding "we will require each applicant to demonstrate that there is a nexus between its request for 100 percent CWIP recovery and the investments being made. Ordinarily, such an incentive would be appropriate for large new investments or in situations . . . where denying such an incentive would adversely affect the utility's ratings. There may be other situations as well where such an incentive is appropriate and we will consider each proposal on the basis of the particular facts of the case.").

[158] *Pub. Sys. v. FERC*, 606 F.2d 973, 979, n.27 (D.C. Cir. 1979) ("[T]he Federal Power Act aim[s] to protect consumers from exorbitant prices and unfair business practices. This purpose can be seen in the statutory requirement that rates be just, reasonable, and nondiscriminatory."); *Xcel Energy Services Inc. v. FERC*, 815 F.3d 947, 952-53 (D.C. Cir. 2016) (quoting *Mun. Light Bds. of Reading & Wakefield v. FPC*, 450 F.2d 1341, 1348 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 989 (1972)) ("It is long-established that the 'primary aim [of the FPA] is the protection of consumers from excessive rates and charges.'").

[159] The structure of the FPA and implementing Commission regulations place the burden on public utilities to demonstrate that the rates they propose are just and reasonable. 16 U.S.C. § 824d(e) (2012); 18 C.F.R. §§ 35.12 and 35.13 (2019).

successfully launch prudence challenges or permit the Commission to adjudicate any disputes on the appropriateness of the application for the particular circumstance. Such policies could also lead to the undertaking of projects without a sufficiently rigorous assessment of the costs and benefits of those projects, simply because consumers would be effectively insuring the developers from risks. This would not promote just and reasonable transmission rates and would undermine the consumer benefit goals of FPA section 219.

Third, the Commission's existing framework for approving project-specific incentives on a case-by-case basis should provide adequate assurance to project developers. To the extent the Commission determines to maintain the rebuttable presumption that currently applies for projects that are vetted through an open and transparent regional transmission planning process, projects selected in regional plans will benefit from the rebuttable presumption that the project will meet the section 219 threshold test of ensuring reliability or reducing congestion. Nevertheless, reduction of transmission developer risks should not conflict with or outweigh the Commission's statutory purpose in implementing section 219, *i.e.*, benefiting consumers. Therefore, consistent with the consumer benefit principle of FPA section 219, the Commission should decline to provide a pre-approval or automatic grant of any incentives to transmission projects, even if approved in a regional transmission planning process.

Q 53) If so, what specific incentives are appropriate for such automatic treatment and how should such incentives be designed?

As noted in response to Question 52, above, the Commission should continue to require case-by-case evaluation of requested incentives to establish a nexus between the incentives and the proposed project. Absent evidence that pre-approval of incentives is needed to ensure consumers' ability to receive reliable and cost effective transmission service on a nationwide basis, it would be contrary to the consumer protection requirements of the FPA, including FPA

section 219 itself, to provide a blanket pre-approval of risk-reducing incentives for transmission projects.

If the Commission does determine there is an evidentiary basis to proceed with pre-approval of any one of the risk-reducing incentives, the Commission should impose conditions to the grant of such pre-approval. At minimum, pre-approval of any such incentives as applied to a particular project should preclude application of an ROE incentive adder or other return-enhancing rate incentives to the project without a filing by the transmission owner or developer supporting the entire package of incentives without pre-approval of any incentives.

Additionally, the Commission should impose sunset dates for automatically authorized incentives, consistent with the discussion below. Furthermore, the Commission should also condition any pre-approval on the applicant's need to make a FPA section 205 filing for continued application of the incentive if the project exceeds cost or in-service estimates by a certain threshold from the estimates provided when the project was selected in the regional transmission planning process. Finally, the Commission should require applicants to submit certain reporting information on projects receiving incentives, as discussed below.

> *Q 54) Should the Commission continue to use certain incentives to seek to place non-incumbent transmission developers on a level playing field with incumbent transmission owners in Order No. 1000 regional transmission planning processes? If so, should the Commission consider requests for such incentives under section 205, or should the Commission consider requests for such incentives for non-incumbent transmission owners under section 219?*

Consistent with the consumer protection principles of the FPA, the paramount consideration in the Commission's incentives framework is benefitting consumers, and this goal should apply irrespective of the status of the particular developer as an incumbent or non-incumbent. With that guiding principle in mind, Joint Commenters note that the Commission has granted regulatory asset incentives and hypothetical capital structure incentives to non-

incumbent applicants under FPA section 205 even when the applicant has not met the Order No. 679 nexus test to further the policy goals of placing non-incumbents on a level playing field with incumbents, thereby encouraging competition.[160] However, the Commission has declined to grant a non-incumbent the abandoned plant incentive or the CWIP incentive under FPA section 205 where the applicant does not satisfy the Order No. 679 requirements for incentive approval on the grounds that incumbents also do not have the advantage of these incentives before a specific project is identified.[161]

At minimum, the Commission should continue to decline to grant the CWIP and abandoned plant incentives to non-incumbents under FPA section 205 in this fashion. The Commission should also refrain from granting a hypothetical capital structure or other return-enhancing incentive under FPA section 205 where the applicant does not qualify for them under the Commission's section 219 regulations and policy. For instance, where a non-incumbent is a wholly owned subsidiary of a large electric utility or other market participant and is affiliated with other wholly owned subsidiaries with transmission projects in other regions, the Commission should scrutinize whether such return-enhancing incentives are appropriate.

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[160] *See, e.g.*, *Transource Wisconsin, LLC,* 149 FERC ¶ 61,180, at P 19 (2014) (granting applicant's request for a regulatory asset incentive under section 205 where applicant did not meet the Order No. 679 nexus test on the grounds that non-incumbent developers wishing to bid on regional transmission projects in the region's competitive solicitation process "must incur early pre-commercial and formation costs, but because they do not have plant in service and/or rates in effect, they do not have a mechanism to recover these costs as they are incurred, as do incumbent transmission owners whose planning-related costs are expensed to transmission operations and maintenance (O&M) accounts that are typically included in transmission formula rates."); *Transource Kansas, LLC*, 151 FERC ¶ 61,010, at P 25 (2015) (granting use of a hypothetical capital structure consisting of 60 percent equity and 40 percent debt for projects developed through Order No. 1000 competitive solicitation to place non-incumbent on level playing field with incumbents who already have such structures established but which remain undetermined for non-incumbents).

[161] *See, e.g.*, *Transource Wisconsin, LLC,* 149 FERC ¶ 61,180, at PP 25, 29 (2014) (denying applicant's request for the abandoned plant incentive and CWIP incentive under section 205 on the grounds that incumbents do not already have the advantage of these incentives but must request it after a specific project is identified); *Transource Kansas, LLC*, 151 FERC ¶ 61,010, at PP 35, 39 (2015) (same).

Moreover, the Commission should decline to extend incentives (and formula rate, including ROE, approval) to as-yet-unformed affiliates. The Commission has previously granted such approval to facilitate non-incumbent participation in competitive transmission processes on a level-playing field with incumbents.[162] Such Commission action has been challenged, *inter alia*, as: (1) improperly absolving yet-to-be-formed affiliates of their obligations under the FPA and the Commission's implementing regulations, which require public utilities to submit filings containing recent cost data that demonstrate that the rates, terms, and conditions by which they propose to provide service are just and reasonable; and (2) improperly shifting the burden of proof away from the yet-to-be-formed affiliates under FPA section 205 to customers. The Commission appropriately clarified on rehearing in one such case that the yet-to-be-formed affiliate must demonstrate in its section 205 filing that it is similarly situated to the parent company to warrant use of the non-incumbents' approved formula rate and incentives.[163]

As it concerns the Commission's inquiry here, the Commission should reconsider its policy of pre-authorizing incentives for yet-to-be-formed affiliates. Granting one yet-to-be-formed affiliate the automatic ability to replicate an affiliate's formula rate and incentives will

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[162] *See, e.g.*, *DesertLink, LLC* , 161 FERC ¶ 61,126, at PP 39-40 (2017), *order denying motion to vacate*, 165 FERC ¶ 61,076, at P 9 (2018) (granting yet-to-be-formed affiliates or subsidiaries authorization to replicate the proposed formula rate and certain incentives to facilitate the formation of additional entities for purposes of participating as nonincumbent transmission developers in Order No. 1000 competitive transmission processes but parties subsequently reached settlement revising the formula rate to provide that, absent a FPA section 205 filing, the formula rate cannot be used by any entity (including affiliates or subsidiaries of the applicant)); *PJM Interconnection, L.L.C. NextEra Energy Transmission MidAtlantic, LLC*, 164 FERC ¶ 61,185, at P 20 (2018) (granting yet-to-be-formed affiliates or subsidiaries authorization to replicate the proposed formula rate and incentives); *Transource Kansas, LLC*, 154 FERC ¶ 61,011, at PP 17-18 (2016), *petition for review denied sub nom. for lack of standing*, *Kansas Corp. Comm'n v. FERC*, 881 F.3d 924 (D.C. Cir. 2018).

[163] *PJM Interconnection, L.L.C. and Northeast Transmission Dev., LLC*, 155 FERC ¶ 61,097 (2016), *order on reh'g*, 158 FERC ¶ 61,060, at PP 20-22 (2017) (affirming prior order granting yet-to-be-formed affiliates or subsidiaries authorization to replicate the proposed formula rate, but clarifying that "an affiliate or subsidiary must demonstrate in its section 205 filing that it is similarly situated to the parent company as to warrant use of NTD's approved formula rate and incentives. Thus, the Commission will not be applying NTD's ROE without consideration for how the facts underlying the service or general economic conditions will have changed.").

create an undue advantage vis-à-vis another non-incumbent that may be seeking to compete in the transmission process. In addition, where the non-incumbents at issue are affiliates of large electric utilities and have affiliates with transmission projects in other regions, their affiliate relationship may ameliorate their relative financial risks and challenges associated with the construction in a new region. It would also be unreasonable to shift to ratepayers the risk of bearing the incentive-based cost as well as the burden of proof to defend against use of such formula rates and incentives. This is particularly true if the existing non-incumbent and the yet-to-be-formed incumbent are not similarly situated with respect to: the scope of projects they are competitively bidding to build, the benefits to customers of that project, or the capital structure and market conditions impacting the appropriate ROE of the existing non-incumbent versus the new affiliate.

12. Transmission Projects in Non-RTO/ISO Regions

Q 55) Are there factors that discourage developers of transmission projects in non-RTO/ISO regions from seeking incentives?

Other than the RTO/ISO participation adder,[164] the Commission's incentives policy applies equally to public utilities within RTO/ISO regions and non-RTO/ISO regions.[165] For instance, the Commission's existing rebuttable presumption for satisfying the statutory test of section 219 applies equally to RTO/ISO and non-RTO/ISO regions.[166] The incentive-based rate treatments for transmission provided in Order No. 679 apply equally to public utility applicants

[164] 18 C.F.R. § 35.35(e) (2019).

[165] The Non-RTO/ISO transmission planning regions are: ColumbiaGrid, Northern Tier Transmission Group ("NTTG"), WestConnect, Florida Reliability Coordinating Council ("FRCC"), Southeastern Regional Transmission Planning ("SERTP"), and South Carolina Regional Transmission Planning ("SCRTP"). *See* 2017 Transmission Metrics, Staff Report Federal Energy Regulatory Commission (Oct. 2017) ("2017 FERC Staff Transmission Metrics Report") at 28, n. 61.

[166] 18 C.F.R. § 35.35(i) (2019).

whether they are building transmission in RTO/ISO or non-RTO/ISO regions.[167] Non-RTO/ISO transmission planning regions are also equally responsible as transmission providers in RTO/ISO regions to follow the Commission's Order No. 1000 regional planning and cost allocation requirements. As such, to the extent public utility transmission developers in non-RTO/ISO regions are not seeking transmission incentives, it is not likely that this action is a result of the Commission's incentive policy. Instead, the relatively low number of incentive rate requests for projects developed in non-RTO/ISO regions may be attributable to region-specific factors, such as the nascence of the non-RTO/ISO Order No. 1000 transmission planning processes or the lack of regional needs identified in the regional transmission planning processes.[168] As such, before considering changes to the Commission's incentives policy with respect to non-RTO/ISO regions, the Commission should first determine if there is empirical evidence that inadequate

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[167] 18 C.F.R. § 35.35(d) (2019).

[168] *See, e.g.*, 2017 FERC Staff Transmission Metrics Report at 19 (noting that non-RTO/ISO transmission planning regions have yet to open proposal windows under Order No. 1000). *See also* ColumbiaGrid 2019 Biennial Transmission Expansion Plan at 3 (Mar. 2019) (finding that the 2017 and 2018 system assessments identified areas of concern but that the "issues in these areas are unlikely to be classified as regional needs since they are mostly local problems where mitigation plans have already been developed or they still require further evaluation by the affected parties."); NTTG 2016-2017 Regional Transmission Plan at 31 (Dec. 2017) (identifying a need for new transmission capacity to serve forecasted load in 10 years; but noting no projects that were eligible for cost allocation were submitted into NTTG's 2016-2017 regional planning process); WestConnect 2016-2017 Regional Transmission Plan - Final at 4 (no regional transmission needs were identified in the 2016-2017 cycle); FRCC Proactive Planning Results and Cost Efficient or Effective Regional Transmission Solution ("CEERTS") Projects (Apr. 15, 2019) (no potential CEERTS projects have been identified); SERTP 2018 Regional Transmission Planning Analyses Summary at 6 (Nov. 29, 2018) ("no potentially constrained transmission facilities were identified in the assessment of the 2018 regional transmission plan . . . .the transmission projects contained within the 2018 regional transmission plan are effective in addressing the transmission needs within the SERTP region"); SCRTP Stakeholder Meeting Presentation for June 13, 2019 at 27 (SCRTP no regional projects received in current regional planning cycle). In addition in the 2018 Long-Term Reliability Assessment of the North American Electric Reliability Corporation (Dec. 2018), NERC reported on the reliability assessment of the eight NERC regions. Of the eight NERC regions that correspond to non-RTO/ISO regions in the United States, the NERC 2018 Reliability Assessment Report provided as follows: (1) FRCC ("the performance of the transmission system is adequate and in compliance with the requirements in the NERC transmission planning standards for the near-term and long-term planning horizon") at 59; (2) SERC – Reliability Corporation ("SERC") ("Entities do not anticipate any transmission limitations or constraints that cause significant impacts to reliability. . . . Constraints will be mitigated by future transmission projects . . . .") at 117; and (3) Western Electricity Coordinating Council ("WECC") ("Currently, it is not anticipated that transmission additions will be needed to maintain reliability in the Western Interconnection during the assessment period, but transmission additions will continue to interconnect renewable resources.") at 149.

transmission is being built in non-RTO/ISO regions and that any such lack of investment is due to the need for incentives as opposed to other region-specific factors.

Q 56) What, if any, additional types of incentives could appropriately encourage the development of transmission in non-RTO/ISO regions?

Absent evidence that needed transmission is not being built in non-RTO/ISO planning processes and that the current incentives framework is inadequate, the Commission should refrain from considering additional types of incentives to support development of transmission in non-RTO/ISO regions. To the extent that there is a justified concern that needed transmission is not being constructed outside RTO/ISO regions, the Commission should identify the factors that are contributing to the lack of construction of needed transmission on a region-specific basis.

C. Existing Incentives

1. ROE Adder Incentives

a. Transmission-Only Companies

Q 57) Does the Transco business model continue to provide sufficient benefits to merit transmission incentives? What information should an entity seeking a Transco incentive provide to demonstrate sufficient benefits?

No, the Transco business model does not provide sufficient benefits to warrant transmission incentives.[169]

There is nothing in FPA section 219 that specifically addresses incentives to promote Transcos. To support its decision to adopt the Transco incentive adder in Order No. 679, the Commission cited the level of investment by Transcos at that point in time.[170] It also held that "the Transco model responds more rapidly and precisely to market signals indicating when and

[169] To the extent the Commission maintains some form of Transco incentive—and it should not, for the reasons stated herein—Joint Commenters address the second part of question 57 in response to Question Nos. 58 and 60 below.

[170] Order No. 679 at P 224.

where transmission investment is needed."[171] These principal bases of support no longer support a Transco incentive adder.

First, previous levels of investment by Transcos are not sufficient to support continuation of the Transco incentive adder on a prospective basis. Second, the transmission industry has undergone material changes in circumstances since the Commission issued Order No. 679. As Commissioner Glick recently explained:

> The electricity sector has changed dramatically in the intervening twelve years [since issuance of Order No. 679], not least because of subsequent Commission reforms, such as Order No. 1000, that have fundamentally altered the transmission landscape. It is certainly not clear that Transcos are superior to other public utilities that can and do invest in transmission facilities—including competitively developed transmission facilities—or that awarding Transcos a higher ROE actually leads to greater transmission investment.[172]

These fundamental changes, coupled with the lack of evidence supporting an increased return for Transcos, undermine the principal bases for the Commission's decision to adopt the Transco incentive adder in Order No. 679.

The Commission has already recognized these changed circumstances in limiting the scope of the Transco incentive adder it established in Order No. 679. Before, and in the wake of, issuance of Order No. 679, the Commission awarded 100 basis point Transco incentive adders.[173] In 2015, however, the Commission reduced the maximum allowable incentive to 50 basis points.[174] In support of its decision, the Commission cited the interests of consumers, concerns regarding the rate impacts of such adders, and current market conditions. With years of

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[171] *Id*.

[172] *GridLiance West Transco LLC*, 164 FERC ¶ 61,049 (2018) (Comm'r Glick, concurring).

[173] *See, e.g.*, *ITC Holdings Corp.*, 102 FERC ¶ 61,182, at P 68, *reh'g denied*, 104 FERC ¶ 61,033 (2003).

[174] *See Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,252, at P 45 (2015). "[A] Transco Adder of less than 50 basis points is appropriate" where the transmission owner is not fully independent of market participants. *Consumers Energy Co. v. International Transmission Co.*, 165 FERC ¶ 61,021, at P 73 (2018) (footnote omitted).

experience and in light of the materially changed circumstances discussed above, these same considerations now warrant elimination of the Transco incentive adder in its entirety.

Further, Transcos face less risk than vertically integrated utilities or diversified utilities with affiliates serving multiple functions. Unlike generation assets, transmission assets and the service they provide, are largely insulated from competition. In addition, the prevalence of formula rates provide Transcos with the benefits of rate certainty and timely cost recovery supervised by a single regulator. Customers should not pay escalated rates that are not reflective of Transcos' risk.

Q 58) Should the Transco incentive remain available to Transcos that are affiliated with a market participant? If so, how should the Commission evaluate whether a Transco is sufficiently independent to merit an incentive?

As explained above in response to Question No. 57, the Commission should eliminate the Transco incentive adder. Assuming, *arguendo*, the Commission maintains some form of Transco incentive, such incentive should only be available to entities that are fully independent of market participants.

In issuing Order No. 679, the Commission grappled with questions regarding the eligibility criteria for the incentive adder. At that time, the Commission declined to adopt a definition of "Transco" that excluded transmission companies with ownership by affiliates. It is clear, however, that freedom from influence or control by a diversified owner was a critical factor that distinguished the Transco business model from other ownership structures.[175] Indeed, the principal benefit on which the Commission relied in establishing the Transco incentive adder was the "eliminat[ion] [of] competition for capital between generation and transmission

[175] *See* Order No. 679 at P 240 ("independence is an important component of the positive contribution of Transcos on investment in needed transmission infrastructure").

functions."[176] When a Transco is affiliated with a vertically integrated or diversified utility, the Transco business model does not eliminate competition for capital or maintain a singular focus on transmission investment. Notwithstanding the other bases for eliminating the Transco incentive adder, customers should not be burdened with higher transmission rates where this characteristic is not present.

Evaluating whether a Transco is sufficiently independent to merit an incentive should be an easy exercise. The general rule should be that transmission owners with any market-participant affiliates are not sufficiently independent to merit a Transco incentive. This presumption should apply regardless of whether affiliate ownership is active or passive or whether the transmission owner and market-participant affiliates operate in the same or an adjacent market.[177] While transmission owners could attempt to rebut this presumption by providing substantial evidence to support a finding that they are, in fact, independent, the Commission's obligation to protect consumers from excessive rates[178] should compel it to establish a high bar to ensure that any Transco incentive yields real benefits that would not be achieved without the incentive.[179]

Q 59) Should a Transco incentive be awarded on a project-by-project basis?

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[176] *Id.* at P 224.

[177] In discussing the importance, or lack thereof, of geographic proximity of operations, Commissioner Glick recently explained that "the potential for [an affiliated transmission owner] to use its assets to benefit nearby affiliates *only strengthens* the case that the [affiliated transmission owner] no longer possess[es] the type of independence the Commission sought to incentivize in Order No. 679." *Consumers Energy Co. v. International Transmission Co.*, 165 FERC ¶ 61,021 (2018) (Comm'r Glick, dissenting, at P 6) (emphasis added).

[178] *See Pub. Sys. v. FERC*, 606 F.2d 973, 979, n.27 (D.C. Cir. 1979).

[179] *Cf. Consumers Energy Co. v. International Transmission Co.*, 165 FERC ¶ 61,021 (2018) (Comm'r Glick, dissenting, at P 2) ("Those incentives—which come directly out of consumers' pockets—must incentivize transmission owners to develop and operate their facilities in a manner that provides consumers with sufficient benefits to justify the extra costs they must pay. Anything short of that is unjust and unreasonable."); *id*. at P 8 ("We must remember that transmission incentives are ultimately paid for by consumers. Therefore, it is especially important that the Commission thoroughly examine its use of ROE incentives, including the Transco adder, to ensure that they are incentivizing actions and investments that will produce meaningful benefits for consumers.").

As explained above in response to Question No. 57, the Commission should eliminate the Transco incentive adder. Transcos could seek project-specific incentives like other transmission owners and developers pursuant to the Commission's existing framework for evaluating applications for such incentives, as discussed above. To the extent the Commission maintains some form of *Transco-specific* incentive adder, however, it should only award that incentive on a project-by-project basis where the Transco demonstrates that the project: (i) would not be developed but for the incentive; (ii) provides real, quantifiable customer benefits that offset the increased cost of the adder; and (iii) that the applicant's status as a Transco facilitated the development of the project or produces particular benefits to consumers. Further, there should be no presumption that any such incentive adder is available for the life of the project. Given that circumstances can, and do, change over time, the Commission should not take any action that limits customers' ability to challenge an existing incentive adder under FPA section 206.

Q 60) Should the Transco incentive exclude assets that a Transco buys, rather than develops?

As explained above in response to Question No. 57, the Commission should eliminate the Transco incentive adder. Assuming, *arguendo*, the Commission maintains some form of Transco incentive, such incentive should not apply to assets that a Transco buys, rather than develops. The principal basis for the Commission's decision to establish the Transco incentive adder was that "the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed" because it "eliminat[es] competition for capital between generation and transmission functions and thereby maintain[s] a singular focus on transmission investment."[180] There is simply no justification for a Transco

[180] Order No. 679 at P 224.

incentive adder where the Transco buys existing assets rather than develops transmission where it is needed.

b. RTO/ISO Participation

Q 61) Should the Commission revise the RTO-participation incentive?

The Commission's policy of granting a 50 basis point adder to a public utility's ROE as a reward for joining an RTO/ISO or remaining a member of an RTO/ISO ("RTO adder") warrants revision. Specifically, the Commission should consider eliminating the RTO adder. To the extent that the Commission elects to preserve the RTO adder, however, Joint Commenters urge the Commission to revise its transmission incentive policy to distinguish between an adder for joining an RTO/ISO and one for voluntarily remaining an RTO/ISO member.

As a preliminary matter, Joint Commenters question whether the RTO adder still serves the purpose of inducing a public utility to join, or retain its membership in, an RTO/ISO. Order No. 679-A describes the incentive adders as "an *inducement* for utilities to join, and remain in, Transmission Organizations."[181] Since Order No. 679's issuance, the organized wholesale markets administered by RTO/ISOs have evolved greatly. As a result of that evolution, the RTO/ISOs report significant efficiency and reliability gains. For example:

- MISO: For 2018, MISO reported that it delivered between $3.2 billion and $3.9 billion in benefits to its members.[182] For the period from 2007 through 2018, MISO's Value Proposition studies reported, "MISO provided the region an estimated $24 billion in cumulative net benefits."[183]

[181] Order No. 679-A at P 86 (emphasis added).

[182] *See* "Value Proposition" *available at*: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ (visited May 28, 2019) ("With growing energy demands throughout MISO's footprint, our services help ensure reliable, least-cost delivered energy. MISO's Value Proposition documents how we unlock billions in annual benefits for the region.").

[183] *See id*.

- PJM: PJM has reported a comparable total annual value of "2.8 billion to $3.1 billion," of which PJM attributed $525 million as related to energy production costs and $475 million related to reliability.[184]

The benefits of RTO/ISO participation, combined with many public utilities' now longstanding membership in an RTO/ISO, arguably have reduced or eliminated any incentive-power associated with the RTO adder. The value generated by today's organized wholesale power markets well executing their core missions appears to provide a greater inducement for joining and remaining in an RTO/ISO than does any RTO adder. Accordingly, Joint Commenters urge the Commission to eliminate the ROE adder.

To the extent the Commission elects to preserve the RTO adder, however, the Commission should revise the transmission incentive policy to distinguish between an adder for new RTO/ISO membership and one for voluntary continuation of RTO/ISO membership. The current, effectively generic application of a 50 basis point adder conflates differences between the incentive appropriate to induce RTO/ISO participation and the lesser incentive appropriate to encourage continued participation. The incentives to induce RTO membership are qualitatively different from incentives to encourage continued membership. Thus, absent the elimination of the RTO adder, the Commission should establish an RTO adder with a range of incentive levels to better reflect the qualitative differences between initial and continued membership in an RTO/ISO.

No justification exists to continue any adder in perpetuity after a public utility has joined an RTO/ISO. The continued availability of an RTO adder long after a public utility has joined an RTO/ISO results in an unjustified windfall to the public utility at the expense of transmission

[184] PJM Value Proposition *available at*: https://www.pjm.com/about-pjm/value-proposition.aspx; *see also* Attachment to Statement of F. Stuart Bressler, III, Ohio House of Representatives Energy and Natural Resource Committee at 5 (Apr. 9, 2019).

customers. As discussed below, the Commission should consider reducing the size of the ROE incentive for RTO membership after a specified number of years from a public utility's membership start date and eliminating the incentive altogether after a public utility has remained a member for a certain number of years.[185] Finally, the Commission should clarify that the RTO adder is a single-use incentive. In other words, if a public utility withdraws from an RTO/ISO or seeks to switch from its original RTO/ISO to another, the RTO adder should not be available.

Q 62) Should the Commission consider providing incentives other than ROE adders for utilities that join RTO/ISOs, such as the automatic provision of CWIP in rate base or the abandoned plant incentive for all transmission-owning members of an RTO/ISO? If so, what other types of incentives would be appropriate?

No. Joint Commenters do not support the automatic award of incentives of any kind. Consistent with longstanding precedent, the Commission should continue to require case-by-case evaluation of requested incentives to establish a nexus between the incentives and the proposed project.[186]

Q 63) If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?

For the reasons discussed in response to Question No. 61, Joint Commenters believe that the current RTO adder of 50 basis points is excessive. To the extent that the Commission continues to provide the RTO adder, the level should be reduced or, in the alternative, capped at the current level of 50 basis points. Finally, the transmission incentive policy should emphasize that the RTO adder is not an entitlement but, rather, a case-specific rate treatment available to a public utility that demonstrates it meets the relevant criteria.[187]

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[185] As discussed in response to Question No. 64, *infra*, Joint Commenters urge the Commission to phase out the RTO adder for both new and existing RTO members after a certain time period.

[186] *See, e.g., American Transmission Systems, Incorporated, et. al*., 167 FERC ¶ 61,203, at P 19 (2019); *American Elec. Power Serv. Corp*., 118 FERC ¶ 61,041, at P 16 (2007).

[187] *See CPUC v. FERC*, 879 F.3d 966.

Q 64) Should the RTO-participation incentive be awarded for a fixed period of time after a transmission owner joins an RTO or ISO?

If the Commission retains the RTO adder, it should consider phasing out the incentive after a certain number of years of a public utility's membership in an RTO/ISO. Joint Commenters also recommend that the Commission initiate a process to phase out the RTO adder for public utilities that are currently members of an RTO/ISO.

An RTO adder awarded to a public utility for joining an RTO/ISO should be allowed to remain in place at the initial level for a four-year period following the effective date of the public utility's membership start date, subject to reduction during the four-year period if warranted by a cap on the overall level of allowed ROE. At the conclusion of the four-year period, the RTO adder should begin to phase out over a subsequent two-year period, subject to a rebuttable presumption, as discussed below with respect to existing RTO/ISO members.

For existing members of an RTO/ISO that are currently receiving the 50 basis point RTO adder pursuant to Order No. 679, the Commission should initiate a process to phase out the RTO adder, subject to a rebuttable presumption. The RTO adder would be rebuttably presumed to decline by 12.5 basis points per year over a four-year period. To commence the phase-out process for existing RTO/ISO members, the Commission's issuance announcing this revision to the Commission's RTO/ISO adder policy should direct each recipient of the RTO adder to submit a filing to implement a phase out or demonstrate that can it overcome the rebuttable presumption and, thus, should not be subject to a phase out.

The phase out of the RTO adder for both new and existing RTO members could be subject to a rebuttable presumption. To overcome this rebuttable "phase down" presumption, the public utility would be required to show (and intervenors would have the opportunity to challenge) that unique factors warrant a deviation from the otherwise applicable adder "phase

out" process. Such a showing could include evidence that the risks or financial constraints associated with the public utility's continued RTO participation are not adequately compensated if the adder is reduced or eliminated.

Q 65) Should the RTO-participation adder be awarded on a project-specific basis?

Joint Commenters do not support awarding the RTO participation adder on a project-specific basis. However, if the Commission retains the RTO adder, certain projects of RTO/ISO participants should be *ineligible* for the adder. Specifically, the RTO adder should be limited to projects approved through the RTO/ISO regional transmission planning process. The RTO adder should *not* be available for projects that are not reviewed in the RTO/ISO regional planning process. Thus, investment in local transmission owner projects that are subject only to the Order No. 890 planning principles (such as Supplemental Projects in PJM) or projects that are not even subject to Order No. 890 (such as asset maintenance projects in CAISO) should not receive the RTO adder. As noted above and described in the Brattle Report,[188] such projects have represented a large proportion of transmission investment in recent years. These projects do not reflect full independent regional planning – one of the key intended benefits of RTO/ISOs.[189] To promote regional planning, these non-regionally planned projects should not be entitled to the RTO adder.

Q 66) In Order No. 679, the Commission found that "the basis for the incentive is a recognition that benefits flow from membership in such organizations and the fact that continuing membership is generally voluntary." Should voluntary participation remain a requirement for receiving RTO/ISO incentives?

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[188] See footnote 22, *supra*.

[189] *See, e.g.*, *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

Yes, the voluntariness of a public utility's participation in an RTO/ISO is essential to its eligibility for the RTO adder, consistent with longstanding precedent, which was recently affirmed.[190] Therefore, the RTO adder should not be available, for example, to a public utility that joins or remains a member of an RTO/ISO due to a merger condition, settlement agreement, or other legal obligation, or that withdraws from an RTO/ISO.[191]

c. Advanced Technology

Q 67) Why have few transmission developers sought transmission incentives for the adoption of advanced technology?

Q 68) Do NERC reliability standards affect the willingness of transmission developers to enhance existing transmission facilities by deploying new technologies because of concerns these technologies may increase the risk of standards violations?

Q 69) Are there any types of transmission incentives that could better encourage deployment of new technologies? If so, please describe them.

Some new transmission technologies like dynamic line ratings and flow controls may have lower capital costs than traditional wires alternatives, and thus transmission owners that earn returns on investment included in rate base may have a disincentive to use them. Transmission providers, however, have an obligation to make prudent investments based on industry standards. A properly functioning planning process should consider and incorporate current "best practices" in use by the transmission industry. Incentives should not be awarded simply because a project incorporates designs and features that are the current industry

[190] *See CPUC v. FERC*, 879 F.3d at 974 ("When membership is not voluntary, the incentive is presumably not justified."); *id*. at 975 ("An incentive cannot 'induce' behavior that is already legally mandated. Thus, the voluntariness of a utility's membership in a transmission organization is logically relevant to whether it is eligible for an adder.").

[191] As discussed in response to Question No. 64, if the Commission maintains the RTO adder for existing members of an RTO/ISO, the Commission's transmission incentive policy should be revised to phase out the RTO adder after a certain number of years of RTO/ISO membership. A public utility that has withdrawn from an RTO/ISO should not be permitted to receive the incentive adder should it decide to return to an RTO/ISO (either the same or a different one) in the future. See response to Question No. 61.

standard.[192] Joint Commenters are unconvinced that promoting new technologies warrants a change in incentive ROE policy so much as to the transmission planning requirements.

2. Non-ROE Incentives

a. Regulatory Asset/Deferred Recovery of Pre-Commercial Costs and CWIP

Q 70) Should the Commission continue to provide regulatory asset treatment and CWIP as incentives? Should these incentives be granted automatically to certain types of transmission projects? If so, how would the Commission determine what types of transmission projects?

The Commission's current policy is generally sound with respect to recovery of pre-commercial costs and 100 percent of CWIP in rate base. Authorizing recovery of these risk-reducing incentives, on a case-by-case basis and when there is a demonstrated nexus between the incentive and the project investment, has proven generally workable since the 2012 Policy Statement. Joint Commenters, therefore, urge the Commission to reaffirm its existing policy with respect to these incentives.

The pre-commercial cost recovery incentive and the CWIP incentive are both ratemaking treatments that may aid in reducing the risks associated with transmission project development and obviate the need for costly ROE adders. The Commission has described the pre-commercial cost recovery incentive and its underlying policy rationale as follows:

> [T]he Commission has permitted recipients of this incentive to expense and recover pre-commercial costs that would otherwise be capitalized in CWIP, thus providing for earlier cost recovery and improving early stage project cash flows. The Commission has also made deferred cost recovery available to applicants to address cost recovery restrictions at the state level and to provide greater flexibility for applicants to recover costs, recognizing that deferred

[192] *Cf. United Illuminating*, 167 FERC ¶ 61,126, at P 63 (finding that proposed project technology's was "not sufficiently novel or innovative" to support an incentive ROE under the 2012 Policy Statement risks and challenges framework).

> cost recovery is intended to "…increase the certainty of cost recovery to encourage more transmission investment."[193]

According to the Commission, the pre-commercial cost recovery incentive "provides up-front regulatory certainty and can reduce interest expense, improve coverage ratios, and assist in the construction of transmission projects."[194] These features substantially mitigate project risk during the construction and development phases for new infrastructure.

Allowing transmission developers to recover 100 percent of CWIP costs in rate base provides similar benefits. In Order No. 679, the Commission described its policy regarding the CWIP incentive:

> CWIP is a return on capital. Since 1987, the Commission's general policy has been to allow only 50 percent of the non-pollution control/fuel conversion construction costs as CWIP in rate base. The remaining construction costs, including an allowance for funds used during construction (AFUDC) which provides a return on those expenditures, generally would have been capitalized and included in rate base only when the plant went into commercial operation, *i.e.*, when the plant became used and useful. Allowing some portion of the costs in rate base prior to commercial operation provides utilities with additional cash flow in the form of an immediate earned return. *See* 18 CFR 35.25(c)(3).[195]

As the Commission observed in the 2012 Policy Statement, "[t]he CWIP and pre-commercial cost incentives both serve as useful tools to ease the financial pressures associated with transmission development by providing up-front regulatory certainty, rate stability and improved cash flow, which in turn can result in higher credit ratings and lower capital costs."[196] As explained above, the Commission has determined that the CWIP and pre-commercial cost

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[193] 2012 Policy Statement at P 13 (citing Order No. 679 at PP 175, 178).

[194] *Id.*

[195] Order No. 679 at P 103 n.70.

[196] 2012 Policy Statement at P 12 (citing Order No. 679 at PP 115, 117, and 163).

recovery incentives may eliminate the need for an incentive ROE adder.[197] The Commission's current policy of requiring incentive applicants to propose measures to mitigate project risk, including through incentive ratemaking treatments such as CWIP or pre-commercial costs, before requesting ROE incentive adders, remains appropriate. Joint Commenters support this policy and reiterate their recommendation that the Commission reaffirm its expectation that project developers request and implement risk-reducing incentive rate treatments before authorizing recovery of ROE adders.

Joint Commenters also strongly urge the Commission to continue authorizing the CWIP and pre-commercial cost incentives on a case-by-case basis and to refrain from granting these or other incentive-based rate treatments to any parties or for any projects on an automatic basis. In comments during the Commission's Order No. 679 rulemaking, several commenters proposed that incentive rate treatments be automatically granted, rather than implemented on an individualized basis in response to FPA section 205 or 206 filings with the Commission.[198] The Commission opted instead to provide potential incentive rate applicants with flexibility concerning the form and timing of filings for incentive rates, specifically authorizing the use of declaratory order petitions at the early stages of project development to provide up-front certainty and aid in project financing.[199] These existing procedural options continue to afford developers flexibility over the scope and timing of their incentive rate requests while ensuring that the Commission is able to exercise meaningful oversight regarding the total package of incentives for a particular developer or project. Moreover, the Commission's particularized scrutiny over incentive rate requests remains critical to ensuring that the rate treatments sought

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[197] *See id.* at P 24.

[198] *See, e.g.*, Order No. 679 at P 68 & n.54.

[199] *See id.* at PP 76-77.

by incentive rate applicants are properly tailored to individual project risks and will help to achieve project development while producing just and reasonable rates for transmission customers.

In lieu of creating a regime of automatic incentive rate treatments to which developers would automatically be entitled and that would result in diminished opportunities for review by the Commission and affected parties, Joint Commenters support the Commission reaffirming its commitment to act promptly on incentive rate petitions, especially those that do not involve applications for incentive ROE adders.[200] Prompt Commission action on incentive filings will provide certainty regarding the cash flow concerns underlying petitions for the CWIP and pre-commercial cost incentives, which will aid in expediting project development.

Q 71) Should the costs of unsuccessful Order No. 1000 proposals be recoverable through regulatory asset and deferred pre-commercial cost recovery incentives? If so, what costs are appropriate for recovery?

No. The risk of expending resources to participate in a competitive solicitation, but not being chosen to develop a project, is a cost of doing business that transmission developers willingly accept in electing to submit bids in a process where participation is entirely voluntary. It would be unfair, and contrary to the Commission's primary ratepayer protection mandate,[201] to allow unsuccessful bidders to be protected from the downside risks of competition (*i.e.*, the opportunity cost of bidding) while enjoying the benefits that competition provides (*i.e.*, the opportunity to construct and earn returns on new transmission facilities).

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[200] *See* Order No. 679 at P 77 (stating that "[t]he Commission will seek to process petitions for declaratory order quickly. While we cannot guarantee Commission action within 60 days of the request (as is statutorily required for section 205 filings), we will strive to meet that standard.").

[201] *See, e.g.*, *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952) (acknowledging that "[a] major purpose of the whole Act is to protect power consumers"); *Pub. Util. Dist. No. 1 of Snohomish County, Wash. v. FERC*, 471 F.3d 1053 (9th Cir. 2006) (stating that the Commission's "obligation to ensure that wholesale rates do not unjustifiably adversely affect the public" is "always a part of FERC's statutory mandate").

In a fully competitive market, an unsuccessful bidder would not be able to recover the costs it incurs to bid for one project from the users of another project. Indeed, doing so would represent a departure from the Commission's longstanding ratemaking principle that customers may be charged for the cost of transmission plant that is "used and useful" in providing service. Although the Commission has applied the used and useful principle flexibly to permit recovery of CWIP and pre-commercial costs,[202] that flexibility is unwarranted and inappropriate with respect to development costs associated with a potential project that will never be made operational. Allowing a cost-recovery mechanism for unsuccessful bid costs would also undermine the market-oriented principles and benefits of competition that animate the Commission's policies favoring competitive transmission development.

Developers should not be artificially protected by ratepayers from the downside risks of competing to develop new infrastructure. Being at risk for the costs of unsuccessfully bidding in a competitive process provides a strong signal to potential participants that proposals should be submitted by entities that have a legitimate chance of being selected and will provide a powerful disincentive to bid by entities that may be poorly qualified, have limited resources or experience, propose projects that are not aligned with the needs identified through the applicable planning process, or lack the financial wherewithal to successfully fund, construct, and place into service a multi-million or billion dollar project. The benefits – for both investors and ratepayers – of competitive transmission development processes are most likely to be realized when there is robust competition among a pool of well-qualified project proponents, all of which are proposing projects tailored to identified regional needs. On the other hand, ratepayers would be harmed if

[202] *See, e.g., Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983) (allowing 50 percent recovery of CWIP costs in rate base as an exception to the "used and useful" standard); *order on reh'g*, 25 FERC ¶ 61,023.

developers are permitted to recover the costs of unsuccessful bidding and proposal activities, because developers then lack adequate incentives to incur these costs efficiently and only as to projects for which they have a reasonable chance of being selected. Guaranteeing cost recovery for every unsuccessful bidder simply turns the notion of competition on its head, inappropriately insulates developers from the costs and risks of legitimate competition, and increases the potential that transmission customers will subsidize projects that were never viable.

To avoid concerns that incumbent transmission owners, which have existing revenue requirements or rates providing the means to recover unsuccessful bid costs, are unduly advantaged relative to new developers, the Commission should confirm as a general policy that the costs of unsuccessful participation in competitive transmission processes are not recoverable through Commission-jurisdictional rates. Such a policy would ensure that incumbents and non-incumbents do not receive disparate treatment, while also protecting ratepayers from exposure to costs that are more appropriately borne by project investors.

b. Hypothetical Capital Structure

Q 72) Should the Commission continue to utilize hypothetical capital structures as a transmission incentive? If so, what entities should be eligible to apply for a hypothetical capital structure?

In general, Joint Commenters support the Commission's existing policy with respect to the formation of capital structure, including its policy of primary reliance on the actual capital structure in setting public utilities' regulated rates of return.[203] At the same time, Joint Commenters acknowledge that offering some flexibility in this policy to permit the incentive-

[203] *See, e.g., Va. Elec. and Power Co.,* 123 FERC ¶ 61,098, at P 73 (2008) (stating that "[t]he Commission has a strong preference for using the actual capital structure of the company in developing its rate of return, unless there is an overriding reason not to do so") (citing *Transcontinental Gas Pipeline Corp.*, 84 FERC ¶ 61,084 (1998); *Allegheny Power*, Opinion No. 469, 106 FERC ¶ 61,251, at P 27 (2004)); *see also Sw. Pub. Serv. Co.*, 48 FERC ¶ 61,156, at 61,599, *order on reh'g and clarif.*, 49 FERC ¶ 61,226 (1989).

based use of hypothetical capital structures in limited circumstances, such as for small or newly-formed companies, may aid in advancing the Commission's policy goal of further transmission development, particularly by non-incumbents. For example, use of a hypothetical capital structure may, as the Commission observed in the NOI, have a stabilizing effect on the capital structure during construction (*see* NOI at P 41) and therefore aid in project financing. To this end, Joint Commenters encourage the Commission to generally reaffirm its existing policy with respect to the hypothetical capital structure incentive. Joint Commenters also urge, however, the Commission to provide limited clarifications regarding the scope and application of this incentive, consistent with the comments set forth below and in response to Question Nos. 73-76.

First, Joint Commenters generally do not support the use of hypothetical capital structures as an incentive ratemaking treatment available to *Commission-regulated public utilities*, because hypothetical capital structures may falsely magnify the risks of an inherently low-risk line of business. Transmission development, as a stand-alone business, represents a relatively low risk for investors, especially when the developing entity engages in inclusive regional planning processes (consistent with existing Commission policies) and the costs of its projects are recovered through Commission-authorized transmission rates, particularly formula rates.[204] As a general matter, investors favor low-risk infrastructure companies that offer stable, predictable returns. Capital markets, therefore, support "thinner" capital structures for transmission-only companies, due to the low-risk nature of their business.[205] For this reason, any Commission-jurisdictional public utility seeking a hypothetical capital structure as an incentive

[204] Even when transmission projects are developed outside of a traditional transmission rate structure, the execution of transmission service contracts in advance with "anchor" customers is usually required for the project to be financed and move forward.

[205] A company is "thinly" capitalized when it has a relatively high proportion of debt in its capital structure relative to the equity share. A "thicker" capital structure has a relatively high proportion of equity in relation to debt.

rate treatment should be required to present compelling evidence of special circumstances requiring the use of a capital structure other than its actual structure in order for a particular infrastructure project to go forward. Moreover, in the event that the Commission agrees to allow a hypothetical capital structure for a public utility in a particular case, use of a "thicker" hypothetical capital structure in such cases should eliminate any need for the simultaneous application of ROE adders.

Second, publicly owned and cooperative utilities participating in transmission projects present special issues, as they are often funded at close to 100 percent by debt. In these circumstances, use of a hypothetical or proxy capital structure is not appropriately considered as an incentive rate treatment; rather, use of a hypothetical or proxy capital structure represents a necessary and pragmatic ratemaking adjustment that is necessary to accommodate participation by publicly owned utilities and electric cooperatives in transmission development. Within reasonable bounds, the Commission should allow non-public utilities to earn transmission returns comparable to those allowed to investor-owned utilities, including through the use of a hypothetical or proxy capital structure. Doing so will facilitate the Commission's policy goal of diversifying participation in transmission planning and development activities. Moreover, support from and participation by publicly owned utilities and electric cooperatives will be important to the advancement of regional and interregional transmission projects in many parts of the country, as discussed above. For these reasons, Joint Commenters urge the Commission to continue to permit the use of hypothetical and proxy capital structures by non-public utilities.[206]

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[206] *See, e.g., City of Vernon, California*, 93 FERC ¶ 61,103, at 61,285-86 (2000) (finding that "Vernon's use of SCE's overall capital structure and the 11.60% return on common equity as the appropriate cost of capital for Vernon in this proceeding"), *reh'g denied*, 94 FERC ¶ 61,148, at 61,564 (2001) (holding that "Vernon's use of SoCal Edison's return on common equity (granted in Opinion No. 445) and capital structure reasonable at this time and under the present conditions").

Q 73) Have hypothetical capital structures been effective in reducing the overall cost of debt by rendering the capital structure more predictable?

The entities that have availed themselves of the Commission's hypothetical capital structure incentive are likely best able to address the particular impacts that use of a hypothetical capital structure has had on their overall financial stability, particularly during the construction and development phases of a project. Joint Commenters would expect that a hypothetical capital structure is important for a relatively small number of companies but, for these companies, this particular rate treatment was relatively important in providing financial stability.

Q 74) In what circumstances, if any, should hypothetical capital structure incentives granted to an entity also be authorized for that entity's yet-to-be formed affiliates?

Joint Commenters do not support extending incentives to as-yet-unformed affiliates, as discussed above in response to Question No. 54. The Commission should fulfill its mandate under the FPA to ensure just and reasonable rates,[207] by undertaking an independent evaluation of the specific incentives that are warranted for a particular utility developing a particular transmission project. The Commission should, therefore, conduct a case-by-case evaluation of the package of requested incentive rate treatments to establish a nexus between the incentives and the proposed project. The Commission should not assume that determinations regarding one company may or should, without scrutiny, be replicated for a possibly unknown number of unidentified affiliates at some unspecified point in the future. Doing so, especially on an automatic basis, would result in an improper shift in the burden of challenging application of rate treatments as unjust and unreasonable from the regulated utility to customers. The Commission should not authorize incentive rate replication but, rather, should consider incentive rate

[207] 16 U.S.C. §§ 824d, 824e.

treatments on a case-by-case basis in response to individual filings by the entities that seek to recover transmission incentives.

Q 75) Under what circumstances, if any, should hypothetical capital structures extend beyond the construction period?

To the extent that the Commission agrees to allow a hypothetical capital structure for a public utility in a particular case, use of a thicker hypothetical capital structure by Commission-regulated public utilities should not extend beyond the construction period. Once a project is constructed and placed into service, the utility's actual capital structure should be used to establish rates, consistent with existing Commission policy.[208]

In limited circumstances and on a particularized basis, Joint Commenters do not oppose the Commission retaining its discretion to authorize the use of a hypothetical capital structure beyond the initial construction and development period. Importantly, and as Joint Commenters address elsewhere in these comments, the Commission should avoid ossifying incentive rate treatments so that they remain in place in perpetuity. As part of its statutory mandate to ensure just and reasonable rates, the Commission should be committed to undertaking a thoughtful review of previously authorized incentives to determine whether the incentives are still needed. The point at which a project is placed into service and its costs become fully recoverable in rates represents an appropriate inflection point at which an entity using a hypothetical capital structure during construction and development may seek continuation of the hypothetical capital structure. As with other incentive-based rate treatments, the Commission should assess continuation of the hypothetical capital structure on a case-by-case basis.

[208] As noted above, the use of a hypothetical or proxy capital structure by a non-public utility is not a matter of incentive ratemaking, but is, rather, a general ratemaking policy that should remain unaffected by determinations in this proceeding regarding hypothetical capital structure as an incentive. The use of a hypothetical or proxy capital structure by non-public utilities and electric cooperatives should be permitted for the life of a transmission project.

Q 76) Should the Commission provide a consistent hypothetical structure (e.g., 50 percent debt and 50 percent equity)? Alternatively, should the Commission cap the equity percentage at some upper limit (e.g., 50 percent)?

Joint Commenters support capping the equity percentage used in the hypothetical capital structure incentive at 50 percent. Hypothetical capitalization ratios that are weighted more heavily than 50 percent toward equity increase the likelihood that project investors will be over-compensated for their project investments at the expense of ratepayers. Although Joint Commenters support the Commission retaining its discretion to review incentive rate petitions on a case-by-case basis and according to the particular circumstances presented by a particular developer and project, hypothetical capitalization ratios in excess of 50 percent equity should not be approved absent a compelling justification.[209]

c. Recovery of the Cost of Abandoned Plant

Q 77) Should the Commission grant the abandoned plant incentive automatically, rather than on a case-by-case basis? Under what circumstances might an automatic award of the abandoned plant incentive be appropriate?

The Commission's current policy is generally sound with respect to the abandoned plant incentive, which permits recovery of 100 percent of prudently incurred costs associated with a project that is commenced but is subsequently abandoned for reasons outside of the applicant utility's control. Authorization of this risk-reducing incentive, on a case-by-case basis and upon a demonstrated nexus between the abandoned plant incentive and the risks and challenges presented by a specific project, has proven largely workable since the 2012 Policy Statement. Joint Commenters, therefore, support reaffirmation of the Commission's existing policy regarding abandoned plant eligibility, including, in particular, the Commission's reliance on this

[209] Although, as explained elsewhere, Joint Commenters do not view the use of proxy capital structures by publicly-owned utilities and electric cooperatives as an issue of incentive ratemaking, in circumstances where a publicly-owned utility proposes to use the capital structure of the utility to which it is interconnected as a proxy, the proxy capital structure should be approved even where the capitalization ratio may exceed fifty percent equity.

incentive as a means of reducing project risk that may obviate the need for ROE adders.[210] Joint Commenters identify below several areas where the Commission's current policy on the recovery of abandoned plant merits clarification.

First, the Commission should not grant abandonment incentives to projects that have not been approved in a regional planning process. While the Commission currently does not require approval in a regional transmission plan as a prerequisite for an award of incentives, limiting the abandonment incentive to regionally approved projects would provide necessary assurance that a project has been found to be the best overall solution for customers in a region to address a particular need. The abandoned plant incentive should not generally be available with respect to projects that were approved solely through internal utility procedures that did not entail an open and transparent stakeholder review. Recovery of 100 percent of abandoned plant costs raises the question of how the Commission will determine whether an abandonment is or is not within the control of the project proponent, especially when the project is cancelled due to unacceptable permit conditions. Where a project, and its subsequent abandonment, are approved through such an inclusive, transparent planning process, the Commission could consider this as one factor in its evaluation of a utility's claim for recovery of prudently incurred abandoned plant costs. On the other hand, entities that choose to forego participation in a transparent, inclusive planning process should assume the risk that a project will later be deemed unnecessary by a permitting authority, and ratepayers should not be required to fund such a developer's decision to follow a more speculative approach at the incentive level of 100 percent abandoned plant cost recovery.

Second, Joint Commenters do not support a policy change that would allow for "automatic" recovery of 100 percent of abandoned plant costs, even for projects that are

[210] *See* 2012 Policy Statement at P 24.

approved in a regional planning process, as discussed in response to Question No. 52 above. The Commission should not lose sight of the fact that its ordinary (non-incentive) policy for abandoned plant cost recovery also mitigates project risk and contemplates an equitable balancing of these risks as between investors and ratepayers:

> This case presents us with a prudent investment in the context of traditional regulation – investments made pursuant to the regulatory compact. An important tenet of that compact is that the interests of the shareholders and ratepayers are to be balanced equitably. [The] statement that ratepayers benefit when a successful project is completed is accurate. But shareholders also benefit when a project is successfully completed. Similarly, when a project that was prudent at its inception is subsequently abandoned, it is appropriate for the ratepayers and the shareholders to share the cost of the unsuccessful project.[211]

The Commission determined that this equitable balance is best achieved through a 50-50 sharing of abandonment costs, explaining that "[n]o party has convincingly demonstrated that allocation of the loss associated with a cancelled plant should be borne more heavily by either the ratepayers or the investors."[212] Unless specific findings are made by this Commission that a particular project warrants incentive rate treatment, the standard, 50-50 sharing approach should continue to apply.

Third, recovery of costs for abandonment should not include carrying charges and should not include any ROE incentive adders. When a project is abandoned, the rationale for mitigating project risk through ROE incentives evaporates. Upon abandonment, the applicant utility should seek to recover its sunk investment costs according to a reasonable amortization schedule that the Commission approves.

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[211] *New England Power Co.*, Opinion No. 295, 42 FERC ¶ 61,016 at 61,077-78 (1988), *order on reh'g*, Opinion No. 295-A, 43 FERC ¶ 61,285 (1988).

[212] *Id*. at 61,081.

Q 78) How, if at all, could the Commission grant the abandoned plant incentive without encouraging transmission developers to pursue unnecessarily risky transmission projects or take unnecessary risks in transmission development? Could such behavior be reduced if the developer shared some risk associated with the abandonment, e.g., 10 percent of abandonment costs? If so, what level of developer risk is appropriate?

Consistent with the comments set forth above, the Commission should not grant abandonment incentives to projects that have not been approved in a regional transmission planning process. Even if the Commission declines to adopt such a policy, retention of the Commission's current case-by-case approach to evaluating project-specific incentives would provide some insulation against unnecessarily risky transmission projects relying on the abandonment incentive.

Q 79) How should the Commission evaluate whether the costs of an abandoned facility were prudently incurred?

The Commission's current framework, which requires a filing under section 205 of the FPA before a utility is authorized to include its abandonment costs in rates, generally remains appropriate. Interested parties have, and should continue to have, the opportunity to object to costs that they contend were not prudently incurred. Assertions regarding the prudency of particular cost items should continue to be addressed based on the specific facts and circumstances presented in individual proceedings involving abandoned plat recovery. The relevant analytical framework to assess prudence is described in *Potomac-Appalachian Transmission Highline, LLC,* 158 FERC ¶ 61,050, at PP 99-101 (2017) ("*PATH*"). As the Commission's ruling in the *PATH* proceeding demonstrates, prudence determinations are fact-intensive and may necessitate hearings to address the specific costs underlying a proposal to recover abandonment costs.

d. Accelerated Depreciation

Q 80) Should the Commission continue to consider accelerated depreciation as an incentive?

Application of an accelerated depreciation period increases concerns regarding intergenerational inequity among ratepayers funding the costs of transmission and, as such, requests for the accelerated depreciation incentive merit careful scrutiny from the Commission. Joint Commenters do not oppose the Commission's continued authorization of accelerated depreciation as a transmission incentive, provided that the Commission does so sparingly and, indeed, it appears that this ratemaking treatment is infrequently applied. This incentive should continue to be approved on a case-by-case basis and only following a Commission determination that accelerated depreciation addresses a demonstrated risk or challenge of a particular project's development.

Q 81) Does the accelerated depreciation incentive provide meaningful benefits to transmission developers?

The developers that have availed themselves of this incentive rate treatment would be in the best position to provide information in response to this question.

Q 82) Should the Commission grant an accelerated depreciation incentive with a generic depreciation period or continue to determine such a period on a case-by-case basis?

In addition to meeting the Commission's nexus test, applicants for accelerated depreciation should be required to demonstrate that the depreciation period that they seek will produce just and reasonable rates. Correspondingly, the depreciation period authorized by the Commission should be no shorter than necessary to mitigate the specific risks and challenges of the project for which the accelerated depreciation is sought. Joint Commenters do not support adoption of a generic depreciation period.

D. Mechanics and Implementation

1. Duration of Incentives

Q 83) Should the Commission limit the duration of a granted transmission incentive? If so, should this limit be based on the type of incentive granted?

Yes, the duration of an awarded transmission incentive should be limited. As discussed in response to Question No. 64, the RTO adder, if it is retained at all, should be phased out over time. Similarly, any project-specific ROE adder should sunset. Joint Commenters recommend that project-specific adders sunset after 15 years. This period would be consistent with the 15-year horizon incorporated in PJM's regional transmission expansion plant ("RTEP") process.[213] A shorter time frame could be applied in particular circumstances if, prior to the sunset date, the Commission makes a determination that the adder is no longer needed or effective. Risk-reducing incentives reduce the targeted risks over time. Consequently, the nexus between any incentive and the underlying investment may become too attenuated to justify the continuation of the incentive in perpetuity.

Q 84) How should the Commission structure a durational component to its incentives? For example, should the Commission provide that transmission incentives automatically sunset after a certain period?

Please refer to Joint Commenters' responses to Question Nos. 64 and 83.

Q 85) Should the Commission provide that a transmission incentive can be eliminated or modified upon a material change to the transmission project? How would such an elimination or modification be implemented? What should constitute such a material change? How would the Commission and interested parties be informed of such a material change?

The Commission should require a project developer to file a notice of any material change in the status of a transmission project following a Commission determination to grant

[213] PJM RTEP Development *available at:* https://www.pjm.com/planning/rtep-development.aspx.

incentives, akin to the reporting requirement for sellers with market-based rate authority.[214] Such notification should describe in detail the material changes in the project and the anticipated consequences of those changes for the project's effects on reliability and/or cost of delivered power. Material changes could include changes in costs, project milestones and timeline, projected benefits, and ownership changes. Such a filing should be made within 30 days of the status change in the docket in which the incentives were granted, served upon all the parties to that docket, and publicly noticed by the Commission. The relevant RTO/ISO should also be required to distribute the filing in a manner similar to the distribution of a transmission owner's annual transmission formula update. Upon receipt of such filing, the Commission should establish procedures to allow interested parties to evaluate and comment on the impacts of the changes in the project as well as the project's satisfaction of the statutory prerequisites for incentives.

Based on the notification of changes to the project and the comments submitted by interested parties, the Commission should reevaluate the appropriateness of incentives in light of the reported changes. Although this reevaluation may generate some uncertainty regarding the continued availability of incentives, it would be inconsistent with the statutory standards to permit developers to receive incentives on the basis of an original project description and alleged consumer benefits for a substantially modified project that may not confer the same benefits to consumers. Absent a reevaluation, a developer could apply for incentives based upon an effectively hypothetical project. Thus, a project that has experienced a material change should retain incentives only if the project-specific risks and challenges remain comparable and it remains likely that the project will deliver the anticipated benefits relied upon to justify the

[214] *See* 18 C.F.R. § 35.42 (2019).

original award of incentives. To the extent the Commission determines incentives are no longer warranted, the Commission should order the incentives to end or adjust the incentive level and, if necessary, order refunds of the revenues recovered pursuant to the incentive.

Q 86) Should there be a process of measurement and verification (or audit) to determine if the expected benefits accrued to consumers?

The awarding of a transmission incentive is based on the Commission's determination that a nexus exists between the risks, costs, *and* benefits associated with a project and the nexus between such factors and the incentives sought for a particular project. The Commission should consider more robust tracking and reporting of the process, costs, and benefits of projects that are awarded incentives. Consequently, just as an incentive recipient must report on the costs and progress of the underlying transmission investment, it is equally important to require measurement and verification ("M&V") of the resulting consumer benefits.

Q 87) If so, how should measurement and verification take place and over what time period?

A public utility's reporting requirement and the M&V process should begin during the siting and construction phases of a project and remain in effect for the duration of the incentive. Where transmission projects are justified based on particular cost savings (*e.g.*, economic projects), auditing should be used to determine if the benefits have been achieved. Joint Commenters recognize that pure reliability benefits could be difficult to track and quantify.

Q 88) Should the Commission consider eliminating an incentive if the project fails to realize its anticipated benefits?

Yes. If there is reasonable basis to believe that a project is failing to realize its anticipated benefits, the Commission might consider issuing a show cause order to an incentive recipient directing the recipient to demonstrate why a particular incentive should not be eliminated. This

review could be prompted by the M&V information described above, a notice of change in status as discussed in response to Question No. 85, or other relevant information.

Q 89) Should there be reporting on projects' expected benefits compared to results, and over what time period?

Yes. As part of its application for an incentive, a public utility should be required to submit an M&V plan designed to track and quantify the consumer benefits generated by its project as well as compare actual data against the projections included in the initial application.[215] The M&V plan should be verified by a reputable, independent third-party with appropriate qualifications. In RTO/ISO regions, this function could be performed by the RTO/ISO. As part of, or in parallel with, the annual filing of the Form FERC-730, the public utility should be required to submit an M&V progress report reflecting the data for the preceding 12-month period. The M&V progress report should also include a comparison of the project's expected benefits and actual benefits realized.

2. Case-by-Case vs. Automatic Approach in Reviewing Incentive Applications

Q 90) What are the benefits and drawbacks of granting incentives on a case-by-case basis, as compared to being granted automatically, with or without related threshold criteria? Would an automatic approach based on established threshold criteria provide additional certainty? If so, how?

As Joint Commenters have explained in responses to other questions above, we do not support the automatic granting of incentives.[216]

The need for case-by-case evaluation of incentives applies to all incentives, including the RTO adder should the Commission opt to retain it. In Order No. 679, the Commission stated,

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[215] An alternative approach could entail submission of a M&V plan as part of a compliance filing following the Commission's grant of an application for an incentive. The granting of the incentive would be conditioned upon the Commission's acceptance of the M&V plan.

[216] *See. e.g.*, responses to Question Nos. 52, 70, 77, and 82.

"we will approve, *when justified*, requests for ROE-based incentives for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization," on a case-by-case basis.[217] Although Order No. 679 contemplated a case-by-case review and granting of incentives when justified, the Commission's practice has been to grant automatically a 50 basis point adder not only for joining but also for remaining a member of an RTO/ISO. Such a practice does not reflect the need to examine utility-specific circumstances to make a reasoned decision that the RTO adder is inducing a public utility to join or remain a member of an RTO/ISO and, thus, conferring the alleged benefits of such membership to consumers.[218] Without evidence that the RTO adder is resulting in consumer benefits that would not have been achieved absent the ROE increase, the increased expense to transmission customers cannot be justified.

Furthermore, recent precedent calls into question the Commission's approach of granting the RTO adder without a case-specific evaluation that considers the voluntariness of a public utility's membership in an RTO/ISO. In *CPUC v. FERC*,[219] the Ninth Circuit properly recognized that an "incentive cannot 'induce' behavior that is already legally mandated" and, therefore, "the voluntariness of a utility's membership in a transmission organization is logically relevant to whether it is eligible for an adder."[220] The Ninth Circuit also stated, "FERC has a longstanding policy that rate incentives must be prospective and that there must be a connection between the incentive and the conduct meant to be induced. This policy is incorporated in Order

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[217] Order No. 679 at P 326 (emphasis added).

[218] "If the Commission contemplates increasing rates for the purpose of encouraging" a policy goal, then the Commission "must see to it that the increase is in fact needed, and is no more than needed, for the purpose." *See City of Detroit v. FPC*, 230 F.2d 810, 917 (D.C. Cir. 1955).

[219] 879 F.3d 966.

[220] *Id*. at 974-975.

679. The policy prohibits FERC from rewarding utilities for past conduct or for conduct which they are otherwise obligated to undertake."[221] Accordingly, a case-by-case evaluation that considers, *inter alia*, the voluntariness of a public utility's RTO/ISO membership, is the appropriate approach to determining whether an incentive should be granted.

In considering project-specific incentives of any kind, the Commission should continue to require case-by-case evaluation of the risks, costs, and benefits associated with a project and the nexus between such factors and incentives sought for a particular project. This approach provides a meaningful opportunity to assess the purported project risks and determine whether such risks warrant the requested incentives. It also allows the Commission's incentive policy to conform to the FPA's just and reasonable rate requirements. Case-by-case approval, while requiring more process, can provide more certainty as a consequence of having a defined evaluation framework. While the automatic award of incentives could relieve administrative burdens, such approach may increase consumer expense by allowing potentially unnecessary and unjustified incentive costs to be charged to consumers. If the Commission were to adopt an "automatic" award of incentives, incentives awarded in this manner should still be subject to challenge, which could undermine certainty in the robustness of the incentive award.

Q 91) If so, how could the Commission determine which incentives should be awarded automatically?

As previously stated in response to Question No. 90, Joint Commenters do not support the automatic granting of incentives. The Commission should continue to require case-by-case evaluation of the risks, costs, and benefits associated with a project and the nexus between such factors and incentives sought for a particular project. This approach provides a meaningful

[221] *Id*. at 977-978. A recent D.C. Circuit decision reinforces the long-standing principle that incentives should not be used for actions that have already been undertaken. *See generally SDG&E v. FERC*, 913 F.3d 127.

opportunity to assess the purported project risks and determine whether such risks warrant the requested incentives. Notwithstanding, if the Commission does consider automatic award of incentives, this policy should be limited to risk-reducing incentives for projects that are fully vetted and approved through an RTO/ISO's regional planning process.

Q 92) If the existing case-by-case approach to incentives is retained, could it be improved? If so, how?

As Joint Commenters have explained, the current case-by-case approach for evaluating project-specific incentives is generally sound. Improvements could be made by incorporating some of the modifications suggested in these comments, particularly providing consumers with assurance that the projected consumer benefits materialize (see responses to Question Nos. 85-89) and protection against incentives that remain in effect long after expiration of the targeted risks (see response to Question No. 64). The Commission should also consider refinements that recognize the increased emphasis the Commission has placed on regional planning since Order No. 679 by limiting the RTO adder (if it is retained at all) to projects approved in a regional planning process (see response to Question No. 65), and adopting a similar prerequisite for other, particularly return-enhancing, incentives. Finally, the Commission should enhance its current policy relating to joint ownership of transmission facilities, as described in response to Question Nos. 50-51.

3. Interaction Between Different Potential Incentives in Determining Correct Level of ROE Incentives

Q 93) Should the Commission establish a more formulaic framework for determining the appropriate level and combination of incentives? If such a framework is created, what elements should it include?

Again, the Commission's framework for considering transmission rate incentive applications on a case-by-case basis, as modified by the 2012 Policy Statement, is generally sound, and the Commission should not adopt "a more formulaic framework."

Q 94) Alternatively, if the Commission continues evaluating incentive requests on a case-by-case basis, how could the Commission provide more detailed explanations in individual cases to better describe how it derives the appropriate level and combination of incentives? If so, what elements should such explanations provide?

The Commission's framework for granting risk-based transmission incentives, as revised in the 2012 Policy Statement, is generally sound.

Q 95) The Commission's current policy is that the total ROE may not exceed the zone of reasonableness. If a transmission project qualifies for ROE incentives, should there be an upper limit or range that the total ROE cannot exceed? If so, what is the appropriate limit or range? Should this vary based on how the Commission sets base ROE?

It is critical that the Commission retain its policy of capping the total ROE (*i.e.*, base ROE plus incentives) at a just and reasonable level. Any other approach would fail to comply with the FPA's just and reasonable rate requirement. The Commission's longstanding precedent relies on the upper end of the discounted cash flow ("DCF") zone of reasonableness to determine the total ROE cap.[222] In a recent notice of inquiry, the Commission contemplates changes to its ROE methodology, including reliance on multiple methodologies instead of the DCF method to determine ROE.[223] Thus, while supportive of retaining the Commission's policy of imposing an upper limit on the total ROE, Joint Commenters are concerned that the upper bound of the zone of reasonable may be excessive, depending on the outcome of the Commission's ROE NOI proceeding. In lieu of using the top of the range of returns as a cap on the total allowed ROE, it may be appropriate to adopt a fixed number of basis points above the base ROE as the cap. The Commission should reserve judgment on this issue until its policies for calculating the ROE zone of reasonableness are more clearly settled.

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[222] *See, e.g.,* Order No. 679 at PP 92-93; *Northeast Utils. Serv. Co.*, 124 FERC ¶ 61,044, at P 71 (2008); *Central Maine Power Co.*, 125 FERC ¶ 61,079, at P 74 (2008); *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143, at P 96 (2011).

[223] *See Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207, at P 34 (2019) ("ROE NOI proceeding").

4. Bounds on ROE Incentives

Q 96) For ROE incentives, to what extent, if any, should the Commission retain discretion to determine the appropriate level of ROE incentives?

The Commission should retain the ability to approve project-specific ROE incentive adders to the extent risk-mitigating transmission incentives cannot address risks faced by the project developer that are not already reflected in the base ROE. Project-specific ROE adders should be rare and reserved for only the highest risk projects and applied only if such risks cannot be adequately mitigated. The Commission also should retain discretion to determine the appropriate ROE level on a case-by-case basis. Finally, any incentive rule or policy, or project-specific incentive, must be just and reasonable and conform to longstanding precedent on the requirements for incentive rates.

Q 97) If the Commission retains discretion with respect to determining ROE incentives, should its discretion be bound within a pre-determined range (e.g., between 50 and 100 basis points)? If so, what is the appropriate range and why?

To the extent the Commission were to retain discretion to determine the appropriate ROE level, it would be useful to establish general guidelines regarding the selection of the ROE level, including a pre-determined maximum cap. To afford the Commission with the most discretion, the guidelines should provide that a request for an incentive might be denied if the applicant does not make the requisite showing. Clearly articulated guidelines governing the Commission's awarding of ROE incentives would foster greater certainty. As discussed in response to Question No. 95 above, it is premature to determine if it is appropriate to retain the Commission's current policy of capping the total allowed ROE, inclusive of incentives, at the top of the range of reasonableness as opposed to using some other mechanism to ensure that the ROE remains at a reasonable level.

E. Metrics for Evaluating the Effectiveness of Incentives

Q 98) What metrics should the Commission use in measuring the effectiveness of incentives, e.g., if certain milestones are reached or only if a transmission project is built and energized?

Because incentives may create the illusion of success in the absence of a clear causal nexus between incentives and project benefits, Joint Commenters submit that a strict "but-for" test and cost-benefit analysis would provide the most effective metrics for evaluating the effectiveness of incentives. Absent application of a strict "but-for" test and cost-benefit analysis for granting incentive rates, it will be difficult, if not impossible, to assess whether incentives are driving beneficial transmission investment, RTO/ISO membership, development of transmission companies, or other Commission goals under FPA section 219. As discussed elsewhere in these comments, it is important to improve *ex post* measurement, verification, and reporting to help ensure accountability for transmission owners and developers that receive incentives.

Q 99) Should the obligation to file Form FERC-730 be expanded to all public utility transmission providers?

In the face of escalating costs associated with transmission infrastructure investment and a lack of transparency regarding particular transmission project costs, Joint Commenters strongly support the expansion of reporting requirements associated with transmission investment by public utilities. Under expanded reporting requirements, public utilities should provide information about all transmission investment activity, not only transmission projects that receive incentives. Extending the obligation to file Form FERC-730 to all public utility transmission providers is one possibility.

Q 100) Should the Commission require that incentive recipients provide additional data through Form FERC-730? If so, what additional information should be provided?

Please see response to Question No. 89.

Q 101) For each transmission project, should the Commission require additional data such as the primary driver of each transmission project (e.g., reliability needs) and the risks entailed in its development (e.g., number of permits required, siting challenges)?

Yes. Joint Commenters believe that such additional data is necessary. Providing additional information about each transmission project should enhance the Commission's ability to assess the status of transmission investment and, thus, ensure that the anticipated consumer benefits materialize.

Q 102) If a transmission project is abandoned, should the Commission require additional data such as the reasons that it failed (e.g., lack of financing, inability to obtain permits, the need for the transmission project did not materialize or was addressed through other means)?

In the event a transmission project is abandoned and the developer seeks to recover abandonment costs, then the Commission should retain the current framework of requiring a section 205 filing in order to seek recovery of such costs.[224] For transmission projects that receive incentives but do not proceed, then information regarding the reasons for such abandonment would be useful to inform the development and application of the Commission's transmission incentive and planning policies.

Q 103) Should the information on annual transmission spending associated with projects that received transmission incentives be broken down by transmission project?

Yes. Furnishing information about annual transmission spending on a project-by-project basis would make such information more accessible to the Commission as well as interested parties, including consumers. Greater transparency also better positions the Commission and others to hold public utilities accountable for seeking to recover only prudently incurred costs through just and reasonable rates.[225]

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[224] *See, e.g.*, *PATH*, 158 FERC ¶ 61,050.

[225] *See* 18 C.F.R. § 35.35(g) (2019).

Q 104) How burdensome would such information requirements be? To ensure that any reporting is not unduly burdensome, should the Commission adopt some type of reporting threshold, such as a voltage, mileage, or dollar threshold, to limit the transmission projects on which it collects information?

As a threshold matter, any consideration of the burden associated with project-by-project information about annual transmission spending from a public utility perspective must be balanced against the usefulness of the information from a consumer perspective. With ultimate responsibility for transmission infrastructure investment costs, consumers are entitled to a reasonable level of detail about the transmission infrastructure for which they are being asked to pay. Finally, Joint Commenters do not support the establishment of a reporting threshold, particularly in the case where the transmission project has been awarded an incentive. If a transmission project is significant enough to warrant incentives, the public utility should be required to provide reasonably detailed information about the transmission project.

Q 105) Should the Commission upgrade the FERC-730 filing format to XBRL or another format or standard? If so, what filing format would be most beneficial and useful to filers and users of the information?

Provided that the content of the information contained in FERC-730 is accessible via the Commission's eLibrary, Joint Commenters do not take a position on changes to the filing format of Form FERC-730.

III. CONCLUSION

Joint Commenters appreciate the opportunity to offer these comments on the Commission's Incentive NOI, and we respectfully request that the Commission consider our views in taking any action on its transmission incentives regulations and policy.

Respectfully submitted,

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APPENDIX

DESCRIPTION OF JOINT COMMENTERS AND CONTACT INFORMATION

The Aluminum Association

The Aluminum Association ("Association"), based in Arlington, VA represents U.S. producers and sellers of primary aluminum, aluminum recyclers, producers of fabricated aluminum products, and industry suppliers. Overall, the aluminum industry directly and indirectly contributes nearly 1% of the U.S. GDP. The Association's policy priorities are focused on trade, infrastructure and transportation, environment and recycling, energy, and workforce development. In the energy area, the Association helps facilitate industrial access to diverse, affordable and reliable energy and raw materials and supports market-oriented, transparent and modernized regulations on energy transmission and ratemaking that reflect the needs of energy-intensive industries and other electricity consumers.

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American Chemistry Council

The American Chemistry Council ("ACC") represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®; common sense advocacy designed to address major public policy issues; and health and environmental research and product testing. The business of chemistry is a $526 billion enterprise and a key element of the nation's economy. It is among the largest exporters in the nation, accounting for ten percent of all U.S. goods exports. Chemistry companies are among the largest investors in research and development. Safety and security have always been primary concerns of ACC members, and they have intensified their efforts, working closely with government agencies to improve security and to defend against any threat to the nation's critical infrastructure.

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American Forest and Paper Association

American Forest & Paper Association ("AF&PA") serves to advance a sustainable U.S. pulp, paper, packaging, tissue and wood products manufacturing industry through fact-based public policy and marketplace advocacy. AF&PA member companies make products essential for everyday life from renewable and recyclable resources and are committed to continuous improvement through the industry's sustainability initiative –Better Practices, Better Planet 2020. The forest products industry accounts for approximately 4% of the total U.S. manufacturing GDP, manufactures over $200 billion in products annually, and employs approximately 900,000 men and women. The industry meets a payroll of approximately $50 billion annually and is among the top 10 manufacturing sector employers in 45 states. AF&PA members own and operate facilities throughout the United States that rely upon the transmission of electricity by FERC-jurisdictional transmission owners. Accordingly, any changes to the Commission's transmission incentives policy will have a direct financial impact on AF&PA members.

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American Public Power Association

The American Public Power Association (APPA) is the national service organization representing the interests of not-for-profit, state, municipal, and other locally-owned electric utilities throughout the United States. More than 2,000 public power utilities provide over 15 percent of all kWh sales to ultimate customers and to businesses in every state except Hawaii. APPA utility members' primary goal is providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA-member electric utilities with the long-term interests of the residents and businesses in their communities. Collectively, public power systems serve over 49 million people.

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The Blue Ridge Power Agency

The Blue Ridge Power Agency is a joint action agency serving 8 members in central and southwestern Virginia. The Blue Ridge members are load-serving entities that own and operate their own electric distribution systems, collectively serving over 270,000 retail customers.

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California Municipal Utilities Association

California Municipal Utilities Association CMUA is a statewide organization of local public agencies in California that provide water, gas, and electricity service to California consumers.

CMUA membership includes electric distribution systems and other public agencies directly involved in the electricity industry. In total, public agencies provide electricity to approximately one quarter of the population in California.

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California Public Utilities Commission

The California Public Utilities Commission ("CPUC") is a constitutionally-established agency charged with responsibility for regulating electric corporations in the State of California. In addition, the CPUC has a statutory mandate to represent the interests of electric consumers throughout California in proceedings before the Commission.

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The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California

The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (the "Six Cities") own and operate municipal electric systems located within the California Independent System Operator Corporation ("CAISO") Balancing Authority Area, and all six Cities participate in the CAISO's markets as both purchasers and sellers. The Six Cities are transmission customers of the CAISO, and they are also Participating Transmission Owners ("TOs") in the CAISO, having previously transferred to the CAISO's operational control certain transmission facilities and entitlements to transmission service. The issues raised by the Notice of Inquiry will have an impact on the transmission revenue requirements of Participating TOs within the CAISO, which are a component of the access charge rates paid by CAISO transmission customers, including the Six Cities. Moreover, certain of the issues in the Notice of Inquiry implicate local, regional, and interregional transmission planning activities, including within and adjacent to the CAISO Balancing Authority Area, which, in turn, may impact access to and the deliverability of resources within the CAISO. As transmission customers, Participating TOs, market participants, and load-serving entities, the Six Cities have a direct and substantial interest in the Commission's transmission incentive rate policies and, in particular, in the issues identified in the Notice of Inquiry.

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Electricity Consumers Resource Council

Electricity Consumers Resource Council (ELCON) is the national association representing large industrial consumers of electricity. ELCON member companies produce a wide range of products from virtually every segment of the manufacturing community. ELCON members operate hundreds of major facilities and are consumers of electricity in the footprints of all organized markets and other regions throughout the United States. Reliable electricity supply at just and reasonable rates is essential to our members' operations.

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The Industrial Energy Consumers of America

The Industrial Energy Consumers of America (IECA) is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 3,700 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer,

insulation, glass, industrial gases, pharmaceutical, building products, automotive, brewing, independent oil refining, and cement.

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The Maryland Office of People's Counsel

The Maryland Office of People's Counsel is an independent state agency that represents the interests of residential consumers in utility cases. Pursuant to Maryland Public Utilities Code Annotated, §2-205(b)(2016), the People's Counsel "may appear before any federal or state agency as necessary to protect the interests of residential…users of [gas, electricity or other regulated services]."

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Modesto Irrigation District

Modesto Irrigation District ("MID") is an irrigation district, organized and operated under the laws of the State of California, which undertakes both electric and water operations. With regard to its electric operations, MID owns and operates facilities for the generation, transmission, distribution, purchase, and sale of electric power and energy at wholesale and retail. MID is a fully integrated, fully resourced, credit-worthy utility.

MID's electric system is interconnected with Pacific Gas and Electric Company's ("PG&E") transmission system, and therefore the California Independent System Operator Corporation ("CAISO")-Controlled Grid, under the PG&E/MID Interconnection Agreement. MID is the holder of a percentage share of the Transmission Agency of Northern California's ("TANC")

Entitlement on the California-Oregon Transmission Project and an allocation of TANC's South of Tesla Principles ("SOTP") Entitlement (PG&E Rate Schedule FERC No. 143). Further, MID and the Turlock Irrigation District ("TID") jointly own the Westley-Tracy Transmission Project, which interconnects their systems with the Western Area Power Administration ("Western") transmission facilities at Western's Tracy Station.

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National Association of State Utility Consumer Advocates

The National Association of State Utility Consumer Advocates ("NASUCA") is a voluntary association of 44 consumer advocate offices in 41 states and the District of Columbia, incorporated in Florida as a non-profit corporation. NASUCA's members are designated by laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. Members operate independently from state utility commissions as advocates for utility ratepayers. Some NASUCA member offices are separately established advocate organizations while others are divisions of larger state agencies (e.g., the state Attorney General's office). NASUCA's associate and affiliate members also serve utility consumers but are not created by state law or do not have statewide authority. A list of current NASUCA members can be found at http://nasuca.org/members/.

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New York Public Service Commission

The New York Public Service Commission (NYPSC) is a regulatory body established under the laws of the State of New York with jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State. The NYPSC is a "State Commission" as defined in section 3(15) of the FPA (16 U.S.C. § 796(15)). With respect to the NYPSC, the views expressed in this filing are not intended to represent those of any individual member of the

NYPSC. Pursuant to Section 12 of the New York State Public Service Law, the Chair of the NYPSC is authorized to direct this filing on behalf of the NYPSC.

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Northern California Power Agency

The Northern California Power Agency ("NCPA") is a nonprofit California joint powers agency established in 1968 to construct and operate renewable and low-emitting generating facilities and assist in meeting the wholesale energy needs of its 16 members: the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, Shasta Lake, and Ukiah, Plumas-Sierra Rural Electric Cooperative, Port of Oakland, San Francisco Bay Area Rapid Transit (BART), and Truckee Donner Public Utility District—collectively serving nearly 700,000 electric consumers in Central and Northern California.

NCPA seeks intervention on behalf of itself and its pool members (Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Ukiah, the Plumas-Sierra Rural Electric Cooperative, and the Port of Oakland), all of whom are signatories to the Metered Subsystem Aggregator ("MSSA") Agreement with the California Independent System Operator ("CAISO"). The MSSA Agreement establishes the relationship between NCPA and its pool members and the CAISO. It was approved as a settlement agreement by this Commission on August 30, 2002. The MSSA Agreement is currently on file as Service Agreement No. 457 under the currently effective version of the CAISO tariff, and has been amended twice to maintain consistency with that tariff.

In addition, under the MSSA Agreement, NCPA acts as Scheduling Coordinator for the City of Santa Clara, which has a separate Metered Subsystem Agreement with the CAISO.

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The Office of the People's Counsel for the District of Columbia

The Office of the People's Counsel for the District of Columbia is an independent agency that represents District of Columbia ratepayers and consumers in proceedings before the District Public Service Commission, the Federal Energy Regulatory Commission, the courts, and other local and federal agencies whose jurisdiction or activities effect the cost or reliability of utility service for District ratepayers and consumers.

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The Public Utility Law Project of New York

The Public Utility Law Project of New York, Inc., is a 501(c)3 nonprofit organization that has advocated for universal service, affordability, and customer protections for New York State utility consumers since 1981. PULP has a four decade-long history of protecting, empowering and representing New York's low-income utility consumers. Some of our accomplishments include: crafting the Home Energy Fair Practices Act ("HEFPA"), a model for a national "Utility Consumer Bill of Rights" that protects 10 million residential electric and gas consumers in New York State; advocating for low-income gas and electric rates; pioneering lifeline telephone assistance in New York; protecting cable and telephone customers, and combatting shutoffs, shared meter and inequitable sub-metering.

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Transmission Agency of Northern California

The Transmission Agency of Northern California ("TANC") is a joint powers agency established by a group of California publicly-owned utilities in 1984. TANC is a "municipality" as defined in section 3(7) of the Federal Power Act, 16 U.S.C. § 796(7) (2012). TANC's initial purpose was to plan, design and construct the California-Oregon Transmission Project ("COTP"), a 340-mile long, 500-kV AC transmission line between the California-Oregon border and Central California. The COTP was completed and energized in 1993. TANC's primary purpose is to provide electric transmission to its Member utilities through transmission line ownership or contract arrangements. As the project manager for the COTP, TANC is responsible for its day-to-day operation and maintenance, and any potential upgrades to the line.

TANC's current Membership includes 15 publicly-owned utilities in the cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah, as well as Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District. Plumas-Sierra Rural Electric Cooperative is an Associate Member.

TANC is a member of WestConnect, wesTTrans, and the Western Electricity Coordinating Council. In addition, TANC is registered with the North American Electric Reliability Corporation as a Transmission Owner, Transmission Planner and Transmission Service Provider.

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The Virginia Office of the Attorney General Division of Consumer Counsel

The General Assembly of Virginia established the Division of Consumer Counsel within the Office of the Attorney General to represent the interests of the people of Virginia as consumers. Va. Code § 2.2-517. In this capacity, the Virginia Office of the Attorney General, Division of Consumer Counsel is duly authorized to appear before governmental commissions, agencies, and departments to represent and be heard on behalf of Virginia consumers' interests.

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