UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF TRANSMISSION ACCESS POLICY STUDY GROUP

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The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to comment on the March 21, 2019 Notice of Inquiry Regarding the Federal Energy Regulatory Commission's ("the Commission") Electric Transmission Incentives Policy ("NOI").[1]

EXECUTIVE SUMMARY

TAPS sees no need for fundamental reform of the Commission's incentive policies, particularly for project-based incentives. The Commission's approach to incentives under Order 679[2] and the 2012 Policy Statement,[3] combined with the assurance of cost recovery plus a return on equity ("ROE"), successfully reversed the long-term decline in transmission investment that spurred Congress to enact Section 219 of the Federal Power Act ("FPA").[4] Transmission investment has skyrocketed since

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[1] 166 FERC ¶ 61,208 (2019).

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

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

[4] 16 U.S.C. § 824(s) ("Section 219").

2006,[5] and shows no signs of slowing down. Transmission owners ("TOs") tout to investors the low risk and strong returns these investments offer, and TOs and developers are competing and litigating for the opportunity to construct and own transmission.[6] Existing policies are effective in getting needed transmission built, without inflating the already dramatic increases in transmission rates being experienced. Specifically:

- ***TAPS strongly supports retention of the existing risks and challenges approach as implemented through the 2012 Policy Statement.*** Section 219 provides for incentives to promote transmission investment that benefits consumers by ensuring reliability and reducing congestion. Under the current approach, once the threshold consumer benefits showing is satisfied, the focus is on nexus—whether incentives are needed to induce investment given the project's risks and challenges. The 2012 Policy Statement emphasizes risk-reducing incentives, which mitigate development and financial risks and thus help get the project built (along with the applicant's risk reducing measures). While allowing for ROE incentives when warranted, the total package of incentives must be tailored to the risks and challenges of the particular project not accounted for in base return ROE (taking account of the risk-reducing incentives), as evaluated on a case-by-case basis. This approach keeps rates just and reasonable, as Section 219(d) requires.[7]

- ***Granting incentives based on the Commission's direct evaluation of project benefits will produce excessive incentives.*** Awarding incentives on the basis of project benefits alone, and eliminating consideration of whether the incentives are needed to induce investment given the project's risks and challenges, will not ensure that incentives are rationally related to *promoting* transmission investment. Rather than producing tailored incentives that are "in fact needed and [are] no more than is needed, for the purpose,"[8] benefits-based incentives will amount to a "'bonus' for good behavior"—an approach the Commission rightly rejected in Order 679 (P 26).[9]

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[5] Johannes P. Pfeifenberger, et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* at 14-15, Brattle Group (2019), https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf.

[6] *See* Part III, response to Question ("Q") 1. In Part III of these comments, TAPS responds to the NOI's questions, copying them (omitting footnotes) into our comments.

[7] *See* Part III, responses to Q 1 and 2.

[8] *City of Detroit v. FPC*, 230 F.2d 810, 817 (D.C. Cir. 1955) ("*City of Detroit*"). *Accord Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984) ("*Farmers Union*").

[9] *See* Part III, response to Q 4.

- ***Granting incentives based on the Commission's evaluation of individual project benefits also threatens to undermine long-standing policy initiative*s *necessary for just and reasonable rates.*** The Commission has found the Orders 890[10] and 1000[11] planning processes to be necessary to satisfying its obligations under Section 206[12] and consistent with Section 217.[13] Evaluation of difficult-to-quantify claimed benefits that rely on complex factual and modeling issues is better achieved through a regional planning process that holistically considers the region's needs, transmission and non-transmission alternatives, and relative costs, than on a piecemeal, individual project basis by the Commission in a hearing process.[14]

- ***An approach that grants incentives using characteristics as a proxy for benefits is plainly inconsistent with the FPA.*** Simply assuming benefits does not eliminate the obligation to quantify consumer benefits from incentive rates, or to ensure that the incentive is worth the increased rates and no more than is needed to induce the benefits. A characteristics-based approach should be rejected as arbitrary.[15]

- ***Any movement away from the risks and challenges framework should be guided by core principles.*** While TAPS urges strongly against abandoning the risks and challenges framework as implemented through the 2012 Policy Statement, we identify principles that are necessary (although still not sufficient) to ensure that any revised policy is consistent with Section 219. These include limiting incentives to truly exemplary voluntary projects; requiring benefits to be clearly defined and quantified in relation to projected costs that must be confirmed before ROE incentives are implemented; limiting the duration of incentives to no more than ten years (or, if not, requiring periodic accountability for claimed project benefits and costs); ensuring that only cost-effective and efficient projects receive incentives by respecting and supporting the Order 1000 and Order 890 planning processes; and maintaining case-by-case review and other procedural and substantive protections.[16]

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

[11] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), *reh'g denied*, Order No. 1000-A, 139 FERC ¶ 61,132 ("Order 1000-A"), *on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *review denied sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam), *reh'g en banc denied*, No. 12-1232 (D.C. Cir. Oct. 17, 2014).

[12] 16 U.S.C. § 824(e) ("Section 206").

[13] 16 U.S.C. § 824(q) ("Section 217").

[14] *Id*.

[15] *See* Part III, response to Q 12.

[16] *See* Part III, response to Q 5.

TAPS would support limited changes to the Commission's incentives policies:

- ***Project-based, above-cost incentives should be restricted to ten years and capped at a reasonable level through a mechanism not dependent on the top of the proxy group***. There is no demonstration that life-of-project ROE incentives are needed to induce investment. Extending incentives beyond ten years is particularly problematic if a benefits-based incentive regimen is adopted. While a cap on summed ROE adders is needed, it should not be tied to the top of the range of proxy results, which is statistically unsound and unpredictable. The maximum, cumulative project-based incentives should not exceed 100 basis points, and the maximum cumulative non-project-based incentives should not exceed 50 basis points.[17]

- ***The RTO Adder should be phased out or reduced.*** At the time the ROE adder for participation in an independent system operator or regional transmission organization (together, "RTOs") ("RTO Adder") was initially made available, RTOs were in their infancy. Today, RTOs operate the grid for at least two-thirds of the nation's load, and offer a significant range of benefits and market opportunities to induce participation. Meanwhile, the cost impact of the adder on businesses and consumers is enormous—roughly $400 million per year and growing.[18] TAPS urges the Commission to limit the RTO Adder to no more than ten years from a TO's initial RTO participation (inclusive of any years when a TO participated in a different RTO, or when a predecessor owner of the recipient's transmission system participated in an RTO). Such recalibration would comport with Section 219(c)'s mandate to provide an incentive *for joining* an RTO, while ensuring that the costs of the adder do not outpace the benefits.

- ***The Transco Adder should be revisited.*** Industry changes since the Commission first established the Transco Adder warrant reexamination of its use as a means to promote transmission development. To the extent it is still warranted, it should be limited to fully independent Transcos. Providing adders to less-than-fully-independent Transcos emphasizes form over substance, incentivizing corporate structures that remain exposed to market participant influence over transmission investments the Transco chooses (or does not choose) to make. We also ask that any Transco Adder be time-limited (e.g., five years) and restricted to new facilities.[19]

- ***The Commission should retain and strengthen the 2012 Policy Statement's encouragement of joint ownership.*** Joint ownership with public power is a Commission-endorsed, risk-reducing measure that brings together Section 219(b)(1)'s goal of promoting capital investment in the grid "regardless of the ownership of the facilities," and Section 217(b)(4)'s directive that the Commission "facilitate[] the planning and expansion of transmission facilities to meet the reasonable needs of

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[17] *See* Part III, responses to Q 83-84 and 97.

[18] *See* Part III, response to Q 61-66 subpart i.

[19] *See* Part III, response to Q 57-60.

> load-serving entities." The 2012 Policy Statement rightly recognizes joint ownership as a risk-reducing measure that ROE incentive applicants should consider.[20] The Commission should enhance that encouragement, including by establishing a rebuttable presumption that an incentive applicant's failure to provide a meaningful opportunity for joint ownership on a load-ratio-share basis to the transmission-dependent utilities ("TDUs") that will bear the cost of the facility demonstrates that the applicant has not sufficiently minimized risk prior to seeking incentives.[21]

I. INTEREST OF TAPS

TAPS is an association of TDUs in more than 35 states promoting open and non-discriminatory transmission access.[22] Representing entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS has long recognized the need for a robust transmission infrastructure to provide non-discriminatory transmission access and foster competition, thereby enabling TAPS members to meet their load reliably and affordably. As TDUs, TAPS members pay transmission rates that are substantially increased when the Commission approves above-cost incentives, and participate, when possible, in transmission development projects.

TAPS has participated actively in numerous Commission proceedings concerning transmission planning, pricing, and incentives policies, including those underlying Order 679 and the 2012 Policy Statement. TAPS has supported use of risk-reducing incentives, rather than cost-increasing incentives, and use of the Commission's incentive policy to encourage inclusive joint ownership arrangements, which have a track record of getting

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[20] 2012 Policy Statement P 24 & n.33.

[21] *See* Part II.

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

transmission built that meets the needs of all load-serving entities ("LSEs") that rely on the grid, consistent with the mandate of Section 217(b)(4).

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II. THE COMMISSION SHOULD MAINTAIN AND STRENGTHEN SUPPORT FOR INCLUSIVE JOINT OWNERSHIP ARRANGEMENTS

Inclusive joint transmission ownership arrangements are an effective means to getting needed transmission facilities built. As TAPS has previously described,[23] such arrangements, whether structured as an inclusive Transco,[24] a shared system,[25] or joint

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

[24] E.g., Vermont Electric Power Company ("VELCO"), formed in 1956, which features municipal and cooperative participation, is an early example. *See* TAPS White Paper at 2. The ownership structure contributes to VELCO's ability to influence legislation and secure regulatory and siting approvals. It also is an important vehicle for collaboration among all Vermont utilities for purposes of VELCO's project planning, operations, and cost allocation decisions. *See* VELCO, *History*, https://www.velco.com/about/history (last visited June 25, 2019).

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

ownership of new transmission facilities,[26] result in collaborative and inclusive planning, development, and siting of transmission, and have proven highly effective in getting transmission built to meet the needs of all LSEs, the objective of Section 217(b)(4). Benefits include:

1. *Inclusive joint ownership makes joint planning real*. Although the Commission has issued rules to promote open and transparent planning, there is a big practical difference when all LSEs are at the table as owners, aligning the ownership structure with the reality of the way the network operates and should be planned. When diverse parties are owners, greater openness and transparency, and more balanced decisionmaking flow automatically.

2. *Inclusive joint ownership results in a better and more efficient transmission system planned to meet multiple needs*. This has been the experience of TAPS members in Wisconsin, where combining multiple systems into one jointly owned Transco (American Transmission Company, LLC ("ATC")) has led to a more rationally developed system than balkanized planning and construction. We also see it in CapX2020, which consists of eleven investor-owned, municipal, and rural cooperative utilities in Minnesota, North Dakota, South Dakota, and Wisconsin that jointly plan needed transmission upgrades and have opportunities to jointly own those facilities.[27] This approach is far better than reactively planning for discrete transmission or interconnection service requests after the requests are made.

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

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

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undivided share of the entire joint system; owning discrete facilities; owning new facilities. *See* TAPS White Paper at 2-3.

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

[27] CapX2020 Webpage, http://www.capx2020.com/ (last visited June 21, 2019) ("CapX2020 Webpage").

5. *Inclusive joint ownership makes cost allocation easier to resolve, although it still remains a thorny issue*. TDUs face adverse competitive impacts from the obligation to pay the increasing costs of transmission,[28] while transmission owning LSEs have an earnings opportunity, rather than simply an obligation to pay. Joint ownership arrangements can provide TDUs a comparable opportunity to hedge those cost increases. For instance, the transmission rates paid by ATC customers have materially increased because of ATC's major construction program. Through their ownership in ATC, however, municipal and cooperative owners have been able to partially offset that increase. This ability has made it much easier for them to support ATC's build-out.

6. *Inclusive joint ownership spreads the risk of major projects broadly and provides a variety of sources of capital for projects*. The financial diversity and strength achieved through joint ownership arrangements should be increasingly valuable. Rating agencies have recognized that ATC's inclusiveness is a significant benefit.

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

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

9. *Inclusive joint ownership arrangements can reduce transmission rates.* Where public power ownership is direct, transmission ratepayers receive several rate-reducing benefits. Public power utilities are not subject to income taxes, and they flow their tax savings through to ratepayers. Their lower debt cost further reduces rates. Even when set on a hypothetical basis, public power utilities' capital structures commonly include less equity than investor-owned utilities' actual capital structures.[29] While not all these rate-reducing attributes apply to inclusive Transcos, some may depending on the particular corporate structure. For example, the lack of tax allowance for public power owners reduces ATC's rates.

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

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[28] *See* Part III, response to Q 1.

[29] *See* Part III, response to Q 72.

While joint ownership arrangements have a long history of success,[30] results of recent joint ownership arrangements are impressive. For example, ATC grew from $550 million in assets in 2001 to $5 billion, building more than 710 miles of new transmission, and connecting more than 6,220 MW of new generation.[31] CapX2020 has completed nearly $2 billion investment in 800 miles of transmission including four 345 kV lines and a 230 kV line, making it the largest development of new transmission in the upper Midwest in 40 years.[32] As described by Tim Carlsgaard, President of Otter Tail Power Company, in CapX2020's August 30, 2017 press release: [33]

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

Joint ownership advances Section 219(b)(1)'s goal of promoting capital investment in the grid "regardless of the ownership of the facilities," opening up the TO club. And Section 217(b)(4) directs the Commission to exercise its "authority . . . under the Act in a manner that facilitates the planning and expansion of the transmission facilities to meet the reasonable needs of load-serving entities," imposing a "requirement for the Commission"[34] significantly furthered by joint ownership arrangements. Thus,

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

[31] ATC, *What We Do*, https://www.atcllc.com/about-us/what-we-do/ (last visited June 21, 2019).

[32] CapX2020 Webpage.

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

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

Section 219(b)(1), coupled with Section 217(b)(4), call for the Commission to target incentives to promote inclusive joint ownership arrangements.

The Commission has repeatedly encouraged joint ownership, highlighting the value of "increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the grid by transmission customers."[35] It has recognized that TDU participation is consistent with Section 219's goals of "encouraging a deep pool of participants,"[36] and benefits consumers as well as TDUs that can offset increasing transmission rates.[37] While the Commission was previously reluctant to go beyond mere encouragement,[38] the 2012 Policy Statement took a significant step forward. It stated that the Commission expected an ROE incentives applicant to demonstrate that it is appropriately minimizing its risks during project development, and identified joint ownership arrangements as a risk-reducing measure to be considered:[39]

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

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

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

[38] *See* Order 679 PP 356-57; Order 679-A P 102; Order 890 P 594; Order 1000 P 776. For example, the Commission has rejected intervenor arguments questioning the claimed risks supporting significant ROE incentives where applicants have turned down public power offers to invest in the project (*see Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152, PP 70, 87 (2010)), or failed to seek investment partners that would reduce that risk, *Cent. Me. Power C*o., 135 FERC ¶ 61,136, PP 36, 42 (2011). *See also Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, PP 45, 47-50 (2009) (finding nexus without addressing intervenor argument that applicant's claim that an ROE inducement is needed is undermined by its failure to offer participation to public power entities with lower financing costs), *clarified and reh'g denied*, 130 FERC ¶ 61,044 (2010).

[39] 2012 Policy Statement P 24 & n.33.

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

While helpful, this statement has yet to bear significant fruit. With limited exceptions,[40] investor-owned utilities continue to be reluctant to share transmission ownership with TDUs, preferring to keep transmission investments at Commission-approved ROEs to themselves.[41] Several TAPS members have sought to achieve joint ownership by partnering with GridLiance[42] to propose non-incumbent projects through

[40] For example, TDU investment in previously planned CapX projects continued post-2012. WPPI Energy ("WPPI") has an approximately $15.2 million investment in the CapX Hampton-Rochester-La Crosse 354 kV line, energized in 2015. WPPI also has an approximately $6.8 million investment in the Badger Coulee 345 kV line, energized in 2018, which connects the Hampton-Rochester-La Crosse line to the Madison, Wisconsin area. Cedar Falls Utilities, a participant in TAPS member Midwest Municipal Transmission Group and a joint owner with MidAmerican Energy Company ("MEC") in the Webster, IA, substation, was invited to participate in a Midcontinent Independent System Operator, Inc. ("MISO") 2011 Multi-Value Project. Working with MEC, Cedar Falls transferred that interest to another MISO Multi-Value Project, in which it was able to invest $4 million in a jointly owned line energized in 2015.

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

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

[42] GridLiance, formed in 2014, has as its mission "To provide our partners with opportunities to invest in regulated transmission development projects, enabling them to earn margins from regionally-funded projects to offset transmission rate increases, as well as receive other benefits, including lower energy costs and increased reliability for their customers, while providing greater access to renewable energy sources." GridLiance, *About Us*, http://www.gridliance.com/about/ (last visited June 21, 2019).

the Order 1000 competitive process, or in investments to improve service reliability for TDU communities. So far only one of those efforts has moved forward.[43] And even where a TAPS member secured state commission approval of an investor-owned utility's stipulation and agreement that it "agrees with co-ownership,"[44] no joint ownership has actually occurred. The contemplated Memorandum of Understanding to implement that commitment—intended to have been completed within fifteen days in 2006—has never been executed, despite years of negotiations.

The Commission should retain and strengthen the 2012 Policy Statement's inducement of joint ownership. Where a TO seeking ROE incentives has not offered broad joint ownership, its request should face heightened scrutiny, if not outright rejection. An applicant that refuses to consider—or worse yet, turns down—TDU offers to participate undermines any claim that incentives are needed to induce investment in the project.

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

[44] *See Order Adopting Stipulation and Agreement and Granting Applications* PP 62-63 & Ordering Paragraph D, *Sw. Power Pool Inc.*, State Corporation Commission of Kansas Docket Nos. 06-SPPE-202-COC and 06-WSEE-203-MIS (Sept. 19, 2006), http://estar.kcc.ks.gov/estar/ViewFile.aspx/20060919090818.pdf?Id=c7e09bc4-6d81-46d1-98ff-d501bc6c3ec5 (approving TDU participation in ownership of transmission facilities). *See also* the July 14, 2006 *Stipulation and Agreement* Section 15, at 7-8, *Sw. Power Pool Inc.*, State Corporation Commission of Kansas Docket Nos. 06-SPPE-202-COC and 06-WSEE-203-MIS (July 14, 2006), http://estar.kcc.ks.gov/estar/ViewFile.aspx/20060714163903.pdf?Id=a06a90d9-0957-4763-ae7b-4b9377b09eeb ("Westar agrees with co-ownership with Kansas Municipals and/or Kansas municipal energy agencies in projects within the service territories of Westar Energy, Inc. and Kansas Gas and Electric Company to allow the cities and/or the municipal energy agencies to meet requests for Network Integration Transmission Service (NITS) … and that the cities and/or municipal energy agencies can invest in new transmission projects and /or upgrades within the service territories of Westar Energy, Inc. and Kansas Gas and Electric Company for such purposes" and further describing the Memorandum of Understanding to be entered to implement the joint ownership rights).

Thus, any Commission action on incentives should strengthen the 2012 Policy Statement (P 24 n.33) by changing "may be" to "is":

> Evidence regarding whether an applicant for incentives considered joint ownership arrangements is ~~may be~~ relevant in assessing whether the applicant took appropriate steps to minimize its risks during project development.

Applicants should have to state whether they are open to investment on reasonable terms by financially qualified TDUs located in the relevant footprint (e.g., the state or region), and depending on the answer, to either explain why not or identify the criteria to qualify for participation. Where an applicant has not provided a meaningful opportunity for joint ownership on a load-ratio-share basis to TDUs in the footprint that will bear the cost of the facility, there should be a rebuttable presumption that the applicant has not taken all appropriate steps to minimize its risks, and that granting the incentive does not accord with the FPA. Inclusion of TDU participants in the project would provide evidence of the meaningfulness of the offered opportunity.

While the requested reinforcement of joint ownership arrangements should be included in any incentives policy revision, it is absolutely essential if the Commission moves away from a risks and challenges approach towards granting incentives based on evaluating a project's expected benefits or characteristics. Failure to enhance the inducement for joint ownership would leave TDUs subject to ROE-incentive-elevated transmission rates without an opportunity to hedge the increased cost through ownership.

The problem is compounded if the TO's load is shielded from the ROE incentives (e.g., by state regulation of transmission for bundled retail load). In those circumstances, the incentive disproportionately increases TDU rates, causing competitive harm that the

Commission is required to consider.[45] Affording TDUs in the footprint a genuine opportunity to participate in the project and associated incentives (with recovery through Open Access Transmission Tariff ("OATT") Section 30.9 credits or otherwise) mitigates that competitive sting and is consistent with the Commission's FPA obligations.

Finally, if the Commission grants ROE incentives for less-than-fully independent Transcos, it should do the same for inclusive joint ownership arrangements.[46] Broad ownership participation has many of the governance benefits of a fully independent Transco, e.g., preventing one owner from steering the project in a direction that serves its generation interests.[47]

III. RESPONSES TO NOI QUESTIONS

A. Approach to Incentive Policy

1. Incentives Based on Project Risks and Challenges (Q 1-3)

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

a) There is no need to abandon the current framework

TAPS strongly supports retention of the risks and challenges framework, as refined in the 2012 Policy Statement. There is no need to reform that framework, which has successfully spurred substantial transmission development, consistent with the requirements of Section 219.

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[45] *Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 758-60 (1973) (Commission must consider the competitive effects of its regulation); *FPC v. Conway Corp*., 426 U.S. 271, 279-82 (1976) (in setting jurisdictional rates, the Commission is obliged to consider discriminatory impacts in light of non-jurisdictional retail rates).

[46] *See* Part III, response to Q 57-58.

[47] An inclusive Transco would have its own employees and financial life (i.e., bond issuance), but would be semi-independent in that its board-level governance would have a scope and configuration consistent with the intent to incent pluralistic governance.

When Congress enacted Section 219, the country faced a significant decline in transmission development since 1975, while load had doubled and was expected to continue to grow 50% over the next two decades.[48] Given the threat to reliability and high cost of congestion and service interruptions, the Commission viewed Congress as directing it to change its policies: "If Congress had deemed our existing practices sufficient to reverse this trend, there would have been little need to enact section 219."[49]

That is not the case today. The Commission's existing transmission policies have worked, together with other initiatives, to induce significant transmission investments. According to the Edison Electric Institute ("EEI"), investor-owned electric companies and stand-alone transmission companies invested over $116 billion in transmission between 2012 and 2017, and expect to invest another $89 billion between 2018 and 2021.[50] The Brattle Group reports that "U.S. transmission investments have stabilized" at approximately $20 billion per year between 2013 and 2017, after rising steadily from $2 billion per year in the 1990s.[51] Regional statistics are equally impressive:

- In New England, TOs invested nearly $11 billion in transmission between 2003 and March 2019 to improve reliability, coupled with a significant decline in congestion, reliability support, and uplift costs over a similar period.[52]

- According to PJM Interconnection, L.L.C.'s ("PJM") most recent Regional

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[48] Order 679 P 10.

[49] Order 679-A P 14. *See also id.* P 3.

[50] EEI, *Historical and Projected Transmission Investment* (2018), http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf.

[51] Johannes P. Pfeinfenberger, et al., *Transmission Competition Under FERC Order No. 1000: What We Know About Cost Savings to Date* at 6, Brattle Group (2018), https://brattlefiles.blob.core.windows.net/files/14786_brattle_competitive_transmission_wires_10-25-18.pdf ("Brattle Group Order 1000 Discussion Paper").

[52] ISO New England, *Transmission*, https://www.iso-ne.com/about/key-stats/transmission (last visited June 24, 2019).

Transmission Expansion Plan, "[s]ince 1999, the PJM Board has approved transmission system enhancements totaling $37.1 billion," of which "$29.9 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief."[53]

- MISO TOs have constructed $19.1 billion in the region since 2003, with another $12.3 billion reportedly in various stages of design, planning, or construction at the time MISO issued its 2018 Transmission Expansion Plan.[54]

- In SPP, more than $10 billion in transmission upgrades were planned and approved from 2004-2018.[55]

The success of existing policies in spurring investment is well-documented. In 2017, the Commission Staff found "load-weighted transmission investment averaged $2.43 per megawatt hour (MWh) of retail load for all North American Electric Reliability Corporation ("NERC") regions between 2008 and 2015, up from a load weighted average of $2.19 per MWh of retail load between 2008 and 2014 in the 2016 Report."[56] The Energy Information Administration graphically depicted that "[s]pending on infrastructure to deliver power to homes and businesses has increased steadily over the past 10 years," in charts showing dramatic transmission increases on a national and regional basis.[57]

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[53] PJM, *Regional Transmission Expansion Plan* at 3 (Feb. 28, 2019), https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx?la=en.

[54] MISO, *MTEP18* at 40 (2018), https://cdn.misoenergy.org/MTEP18%20Full%20Report264900.pdf.

[55] SPP, *SPP 101: An Introduction to Southwest Power Pool* at 95, https://www.spp.org/documents/31587/intro%20to%20spp.pdf (last visited June 25, 2019). *See also* SPP, *2019 SPP Transmission Expansion Plan Report* (Jan. 8, 2019), https://www.spp.org/documents/56611/2019%20spp%20transmission%20expansion%20plan%20report.pdf (itemizing planned or necessary upgrades and investment placed into service).

[56] FERC Staff Report, *2017 Transmission Metrics* at 5 (2017), https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf ("2017 Transmission Metrics Report").

[57] U.S. Energy Information Administration, *Utilities Continue to Increase Spending on Transmission Infrastructure*, Today in Energy (Feb. 9, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34892.

The trend is evident in increasing transmission rates. For example, between 2012 and 2018, ISO New England Inc. ("ISO-NE") Pool Transmission Facilities rates rose by roughly 50%, from $72.75 per kilowatt year (kW-year), to $119.43/kW-year.[58] Likewise, the California Independent System Operator Corp. ("CAISO") Transmission Access Charge totaled $2.3 billion in 2019,[59] compared to $712 million in 2009.[60] While camouflaged by decreasing fuel costs in some instances,[61] these increases can impose a significant burden, especially in areas with static or declining load growth. And it's not just regionally planned projects that are pushing rates upward. Between 2013 and 2017, 47% of TO investment across the six RTOs was concentrated in investments *not* subject to full regional planning requirements per Orders 890 and 1000,[62] increasing TO revenue requirements by over 100%.[63]

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[58] ISO-NE, *Section II. ISO New England Open Access Transmission Tariff (OATT)*, https://www.iso-ne.com/static-assets/documents/2018/12/section2-rate-summary.xls (last visited June 25, 2019).

[59] CAISO, *January 1, 2019 TAC Rates* (2019), http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJan01_2019_RevisedMar21_2019.pdf.

[60] CAISO, *January 01, 2009 TAC Rates* (2019), http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveJan1_2009_RevisedNov19_2012.pdf

[61] U.S. Energy Information Administration, *Electricity Prices Reflect Rising Delivery Costs, Declining Power Production Costs*, Today in Energy (Sept. 7, 2017), https://www.eia.gov/todayinenergy/detail.php?id=32812 (depicting relatively static electricity prices, with increasing delivery costs offsetting decreasing power production costs).

[62] Brattle Group Order 1000 Discussion Paper at 8. The Commission has recently addressed application and implementation of the Order 890 planning processes in CAISO and PJM. *See Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, P 66 (2018) (Order No. 890 applies to "expansion of the transmission grid."); *Monongahela Power Co.*, 162 FERC ¶ 61,129, PP 72, 77 (2018) (finding PJM TOs' practices in planning Supplemental Projects "inconsistent with Order No. 890 and in violation of the PJM Operating Agreement" because they were "providing transmission planning information, including models, criteria, and assumptions, that is inadequate to allow stakeholders to replicate their planning studies, as Order No. 890 requires.").

[63] American Municipal Power, *DOE Workshop on Electric Transmission Development and Siting Issues* at 3 (Nov. 15, 2018), https://www.energy.gov/sites/prod/files/2018/11/f57/1-2%20Tatum_20181115%20DOE%20Presentation.pdf.

There is good reason for the eagerness of TOs and developers to invest in transmission. Few other investments offer the assurance of cost recovery through formula rates that include a Commission-regulated ROE,[64] with the opportunity for RTO incentives and project-specific incentives if warranted. Investors themselves have touted these investments' "recession-resistant earnings."[65] No wonder TOs highlight their increasing transmission investments when communicating with investors:

- Eversource Energy has for several years centered its earnings increase strategy based on growing its transmission rate base.[66] On its 2018 Year-End Results Investor Call, Eversource reported that transmission rate base growth was a key driver in its earnings per share increase, with further plans to increase projected transmission capital expenditures in the future.[67] Eversource Energy reported similar gains associated with transmission investment for Q1 2019.[68]

- FirstEnergy Corp. ("FirstEnergy"), at its investor presentation regarding 2018 Q4 earnings, boasted the company's "30% transmission rate base as a percentage of total rate base" as "rank[ing] among the largest in the nation," noting that 2018 results benefited from, among other things, "solid execution of [its] growth strategy in transmission and distribution businesses," including

[64] And some states provide direct pass through, via a retail transmission delivery charge, of transmission costs subject to this Commission's jurisdiction. *See, e.g.*, Kan. Stat. Ann. § 66-1237(c) ("All transmission-related costs incurred by an electric utility and resulting from any order of a regulatory authority having legal jurisdiction over transmission matters, including orders setting rates on a subject-to-refund basis, shall be conclusively presumed prudent for purposes of the transmission delivery charge and an electric utility may change its transmission delivery charge whenever there is a change in transmission-related costs resulting from such an order.").

[65] Berkshire Hathaway Inc., *Berkshire's Performance vs. the S&P 500* at 12, http://www.berkshirehathaway.com/letters/2016ltr.pdf (last visited June 25, 2019) (essentiality of electricity service and steady demand as ensuring Berkshire Hathaway Energy's ability to service debt under all circumstances).

[66] Eversource Energy, Investor Call Presentation at 21 (Feb. 5, 2017), https://www.eversource.com/content/docs/default-source/investors/analyst-q4-2015-presentation.pdf?sfvrsn=b87df462_1.

[67] Eversource Energy, 2018 Year-End Results Investor Call Presentation at 13, 26 (Feb. 21, 2019) https://www.eversource.com/content/docs/default-source/investors/2018-q4-and-year-end-results.pdf?sfvrsn=dd0ecb62_0.

[68] Eversource Energy, 2019 First Quarter Results Investor Call at 2 (May 2, 2019), https://www.eversource.com/content/docs/default-source/investors/q1-2019-financial-results-slides.pdf?sfvrsn=2f43c962_0.

a $0.03 quarter-over-quarter increase in earnings per share.[69]

- American Electric Power Company, Inc. ("AEP") identified increased transmission investment as contributing to higher revenues and income in 2017 compared to 2016, and thus higher shareholder earnings.[70]

- Public Service Enterprise Group, Inc. ("PSEG") reported in its 2018 Q3 earnings report that its net income reflected "increased revenue from the ongoing transmission and distribution infrastructure investment programs," with "PSE&G's growth in transmission investment adding $0.02 per share to quarter-over-quarter comparisons."[71] PSEG also highlighted that planned capital improvements were expected to result in a $100 million increase in annual transmission revenues.[72]

These actions attest to the effectiveness of the Commission's existing policies in attracting capital for transmission investments.[73]

The sufficiency of existing policies is evidenced by TOs fighting for the right to build transmission.[74] In one instance in which a developer had been granted a 150 basis point risk-based incentive for new transmission, it unsuccessfully sought to block joint

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[69] FirstEnergy, Quarterly Highlights: 4Q 2018 Earnings Call Presentation at 5, 7 (Feb. 20, 2019), https://investors.firstenergycorp.com/Cache/1500117495.PDF?O=PDF&T=&Y=&D=&FID=1500117495&iid=4056944.

[70] *See* AEP, *2018 Annual Report* at 18, https://aep.com/Assets/docs/investors/AnnualReportsProxies/docs/18annrep/2018AnnualReportAppendixAtoProxy.pdf.

[71] PSEG Investor News, *PSEG Announces 2018 Third Quarter Results* at 2, https://investor.pseg.com/sites/pseg.investorhq.businesswire.com/files/doc_library/file/10-30-18_-_PSEG_Announces_2018_Third_Quarter_Results.pdf (last visited June 25, 2019).

[72] *Id.* at 3.

[73] *See* EEI, *Transmission Investment: Revisiting the Federal Energy Regulatory Commission's Two-Step DCF Methodology for Calculating Allowed Returns on Equity* at 2 (2017), https://www.scottmadden.com/wp-content/uploads/2017/12/ScottMadden_EEI_Transmission_Investment_2017_1214.pdf (calling for "predictable, sustainable, and reasonable returns to balance the risks inherent in transmission investment) ("EEI White Paper").

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

ownership by the host TO—which did not seek that same rate incentive—to claim rights to build and own 100% of the facility.[75] The vigorousness with which TOs fought (albeit unsuccessfully) to retain federal rights of first refusal eliminated in Order 1000 compliance filing processes[76] confirms that TOs view expanding the transmission ratebase on which a TO can earn a Commission-regulated return as a valuable opportunity to be protected, rather than a burden requiring inducement.

Where regions have adopted a competitive solicitation or bidding process to comply with Order 1000, competition has been robust. Developers have sharpened their pencils and made long-term commitments to cap their annual transmission revenue requirement ("ATRR"), ROE, and capital structure to win the project, with significant consumer benefits.[77] CAISO's competitive solicitation process has attracted multiple bidders in eight of the nine competitive solicitations it has conducted.[78] In PJM, non-incumbent transmission developers submitted 46% of proposals received in competitive

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[75] *Pioneer Transmission, LLC v. N. Ind. Pub. Serv. Co.*, 140 FERC ¶ 61,057 (2012). *See also Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, PP 3-14 (2018).

[76] *See Okla. Gas & Elec. Co. v. FERC*, 827 F.3d 75 (D.C. Cir. 2016); *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016); *Am. Transmission Sys., Inc. v. FERC*, 2016 WL 3615443 (D.C. Cir. 2016); *Emera Me. v. FERC*, 854 F.3d 9 (D.C. Cir. 2017).

[77] Brattle Group Order 1000 Discussion Paper at 1, 13, 15.

[78] *See* Comments of the California Department of Water Resources State Water Project, *Competitive Transmission Tech. Conference*, Docket No. AD16-18-000, Att. A at 1-2 (Oct. 3, 2016), eLibrary No. 20161003-5364. The competitive solicitation with a single bidder involved a reactive power support project to connect to a 500 kV bus that was owned by the winning bidder. *See* CAISO, *Miguel 500 kV 375 MVAr Reactive Power Support Description and Functional Specifications for Competitive Solicitation* (2014), http://www.caiso.com/Documents/Description-FunctionalSpecificationsMiguel500kVReactivePowerSupport.pdf. CAISO's 2016-2017 and 2017-2018 planning processes did not identify any projects eligible for competitive solicitation. *See* CAISO, *2016-2017 Transmission Plan* at 383 (2017), *http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf*; CAISO, *2017-2018 Transmission Plan* at 338 (2018), *http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf*.

proposal windows.[79] MISO's Hartburg-Sabine Junction 500 kV Selection Report shows stiff competition, with the winner (NextEra Energy Transmission Midwest, LLC) coming in below MISO's scoping bid and below the median bid, with an ROE fixed at 9.8% with 45% equity, foregoing construction work in progress ("CWIP") and Allowance For Funds Used During Construction ("AFUDC"), and limiting ATRR and Operation and Maintenance ("O&M") costs over the first ten years.[80] The willingness to forgo risk-reducing incentives to win selection speaks volumes to the value placed on the right to construct transmission with assured cost recovery.

At the same time, minimal to flat load growth is actually reducing the need to build transmission in some areas. PJM cancelled the previously-approved Potomac Appalachian Transmission Highline, a 765 kV, 275-mile line connecting West Virginia and Maryland, and Mid-Atlantic Power Pathway, a 500 kV, 230-mile line between Virginia and New Jersey, due to, among other things, reduced growth of electricity demand.[81] And CAISO canceled 13 projects in 2015-2016, citing "materially lower load forecast levels since those projects were approved."[82]

Thus, reform of existing incentive policies is *not* required to induce investment. To the contrary, the overwhelming evidence demonstrates that TOs and developers find transmission to be a very attractive investment under current policies. As Lawrence

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[79] 2017 Transmission Metrics Report at 4.

[80] MISO, *Selection Report: Hartburg-Sabine Junction 500 kV Competitive Transmission Project* (2018), https://cdn.misoenergy.org/Hartburg-Sabine%20Junction%20500%20kV%20Selection%20Report296754.pdf.

[81] *PJM Staff Seeks Removal of Planned U.S. Mid-Atlantic Power Lines*, Reuters (Aug. 8, 2012), https://in.reuters.com/article/utilities-pjm-transmission/pjm-staff-seeks-removal-of-planned-u-s-mid-atlantic-power-lines-idINL2E8J8BAS20120808.

[82] CAISO, *2015-2016 Transmission Plan* at 2 (2016), https://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

Willick of competitive transmission developer LS Power summarized at the June 2016 technical conference, "LS Power does not see a direct link between FERC's incentive policy and competitive processes . . . transmission [is] an attractive investment under traditional cost of service regulation," one worth "aggressively competing [for], taking on additional risk, and providing ratepayer benefits, such as through a binding cost cap."[83]

b) The current framework advances Section 219's goals consistent with FPA requirements

The risks and challenges framework, as refined in the 2012 Policy Statement, is tailored to meet the objectives of Section 219, while ensuring the just and reasonable rates Section 219(d) requires. After satisfying the threshold demonstration that a project benefits consumers by ensuring reliability or reducing congestion (relying on Order 679-A's rebuttable presumption or demonstration),[84] the approach focuses on nexus and tailoring incentives to the risks and challenges of the particular investment that are not accounted for in base ROE. Applicants are required to first examine the use of risk-reducing incentives (e.g., CWIP, recovery of pre-certification expenses, recovery of prudent plant costs abandoned for reasons beyond the control of the TO) to alleviate

[83] LS Power Development, Opening Remarks of Lawrence Willick at 1, *Competitive Transmission Dev. Tech. Conference*, Docket No. AD16-18-000 (Jun. 30, 2016), eLibrary No. 20160630-4020.

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

The consumer-benefits threshold requirement was buttressed by the 2012 Policy Statement's explicit expectation that a project for which ROE incentives are sought "provide demonstrable consumer benefits by making the transmission grid more efficient, reliable and cost-effective" (2012 Policy Statement P 22); its non-exclusive list of projects where ROE incentives may be warranted (*id.* P 21, i.e., the project relieves chronic or severe congestion that has demonstrated cost impacts; unlocks location constrained resources with limited or no access to the market; applies new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities); and its expectation that applicants show consideration of alternatives in a relevant planning process to help identify the project's benefits and its role in promoting a more efficient, reliable, and cost-effective grid (*id.* P 25).

project risks not covered in the base ROE.[85] Where such incentives are requested in combination with ROE incentives, the Commission will review the total package, accounting for risk-reducing incentives in determining whether an ROE incentive is warranted, and if so, the appropriate level.[86] By so limiting ROE incentives, this approach avoids over-compensating applicants for risks addressed through the base ROE or risk-reducing incentives, producing just and reasonable rates as Section 219(d) requires.

Incentive ROE applicants must also demonstrate that they have taken appropriate steps to minimize risks during project development. The 2012 Policy Statement (P 24 & n.33) expressly recognized joint transmission ownership as a relevant risk-reducing measure. As discussed in Part II, that encouragement should be strengthened in any revision to the Commission's incentives policies.

In addition, the existing framework supports regional and RTO planning processes that the Commission has worked for more than a decade to foster.[87] Both through Order 679-A's rebuttable presumption and in the 2012 Policy Statement's expectation that applicants show that transmission and non-transmission alternatives to the project have been or will be considered in the relevant planning process,[88] the risks and challenges framework targets the project's "role in promoting a more efficient,

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[85] 2012 Policy Statement P 16.

[86] *Id.*

[87] *See*, *e.g.*, Order 890 PP 3, 61, 422-35 (requiring coordinated, open and transparent planning); Order 1000 PP 3-10, 42-59 (requiring a regional plan and additional reforms).

[88] *See supra* n.84; 2012 Policy Statement PP 25-26 (consideration in Order 890 or Order 1000 planning process "that provides the opportunity for projects to be compared against transmission or non-transmission alternatives" could satisfy incentives applicant's requirement to demonstrate that alternatives to proposed project considered).

reliable, and cost-effective transmission system."[89] It provides incentives tailored to make it possible to construct projects selected in transmission plans, without the Commission putting its thumb on the scales in a way that undermines planning by granting above-cost incentives to other projects. The current framework thus respects RTOs' independent planning of grid expansion where warranted, after consideration of benefits, costs, and alternatives (including non-transmission alternatives), per 18 C.F.R. § 35.34(k)(7).[90] Stakeholder-vetted RTO regional planning models play a valuable role in state siting processes, enhancing the likelihood of getting needed transmission built.

In sum, because incentives must be tailored to the project's risks and challenges not reflected in base ROE, awarded incentives can meet the just and reasonable standard. As refined by the 2012 Policy Statement, the framework emphasizes reducing project development risks, while allowing for ROE incentives where warranted. It is well-designed to provide the "predictable, sustainable, and reasonable returns to balance the [planning, siting and construction] risks inherent in [transmission] investment" that EEI calls for to attract capital required to support adequate transmission investment.[91] It achieves Section 219's objectives without unnecessarily burdening consumers with excessive costs, and avoids the pitfalls of a benefits-based incentives approach. *See* response to Q 4. The risks and challenges framework should be retained.

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[89] 2012 Policy Statement P 25.

[90] Failure of these processes to eliminate all congestion does not mean they are not effective. For example, in determining which congestion relief projects to pursue, MISO uses multiple future scenarios to evaluate congestion, and numerous alternative projects and their costs, to select the projects that exceed the planning threshold with the highest benefit-to-cost ratio and the ability to address the highest congestion cost. *See* MISO, *MTEP 18* at 93-110, https://cdn.misoenergy.org/MTEP18%20Book%202%20Resource%20Adequacy264875.pdf.

[91] EEI White Paper at 2.

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?

The risks and challenges approach is not a "proxy" for expected reliability and congestion-reducing benefits. Rather, as discussed in response to Q 1, qualifying consumer benefits must be demonstrated *before* incentives tailored to the project's risks and challenges may be awarded under the nexus test; and consumer benefits are treated as "necessary, but not sufficient" to support incentives.

This is consistent with Section 219, which does *not* direct that all projects increasing reliability or reducing congestion be awarded incentives.[92] Section 219(b)(1) provides for incentives to "promot[e] capital investment" in qualifying transmission facilities. It thus calls for consideration of not just whether the project itself is beneficial, but whether incentives sought will be instrumental in getting it built—whether the incentives meets the nexus test, addressing risks and challenges not covered by the base ROE. As discussed in response to Q 1, the 2012 Policy Statement tailors incentives to those needed to *promote* investments that deliver the benefits identified in Section 219, while keeping rates just and reasonable.

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?

Consideration of risks is relevant to both base ROE and ROE incentives. The criteria used for forming proxy groups used to develop the base ROE identify exchange-traded companies that are considered risk-comparable to the overall investment risk of

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[92] *See* Order 679-A P 51 (not every project that increases reliability or reduces congestion will merit incentives), P 60 (rejecting requests to apply incentives to projects undertaken in ordinary course).

the regulated public utility whose ROE is at issue. But they do not necessarily identify a proxy group whose investment risk is comparable to that of a particular project. The risks and challenges inquiry used to consider the need for ROE incentives identifies the project-specific investment risk (remaining after risk-reducing incentives are taken into account) that is not adequately captured by the proxy group and the resulting base ROE.

2. Incentives Based on Expected Project Benefits (Q 4-11)

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?

It would be inconsistent with Section 219 to substitute a one-factor test for the existing two-factor test (i.e., considering projected benefits in isolation, rather than considering both benefits and project-specific risks and challenges), resulting in incentives not rationally related to *promoting* transmission investment. It would also undermine long-standing Commission policy designed to ensure just, reasonable, and not unduly discriminatory rates, and would have other significant practical drawbacks.[93]

a) A benefits-based approach is inconsistent with Section 219

The FPA is a consumer protection statute—one that "aims to protect 'against excessive prices.'"[94] As the Commission has explained "[i]t is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our policies must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives." Order 679 P 21; *see also FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 602 (1944). The current framework

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[93] A characteristics-based approach would be even more arbitrary, suffering from the problems identified below and more. *See* response to Q 12.

[94] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 781 (2016) (quoting *Penn. Water & Power Co. v. FPC*, 343 U.S. 414, 418 (1952)); *see also Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 758 (1973).

strikes that balance. A methodology that awards incentives based on project benefits alone will not, and will result in unjust and unreasonable rates.

Section 219(a) directs incentive rate treatments for transmission that "benefit[s] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." Section 219(d) requires the resulting rates to be just and reasonable. The statute thus calls for tailored application of incentives: the critical question should be not just whether the project is beneficial, but whether an incentive is needed to secure those benefits—i.e., it materially affects voluntary behavior.[95]

For an incentive to be lawful, its increased costs to consumers must be offset by the benefits whose realization depends on the incentive.[96] And the incentive must be no greater than is needed to induce the desired action. As the D.C. Circuit explained in *City of Detroit*, 230 F.2d at 817, "[i]f the Commission contemplates increasing rates for the purpose of encouraging exploration and development . . . it must see to it that the increase is in fact needed and is no more than is needed, for the purpose." *See also Farmers Union*, 734 F.2d at 1503 (rejecting incentive rates because the Commission "must see to it that the increase is in fact needed, and is no more than is needed, for the purpose."). Section 219(d) requires adherence to these precedents. Orders 679 (P 26), 679-A (P 27),

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[95] Order 679-A P 25 (nexus test "ensure[s] that incentives are not provided in circumstances where they do not materially affect investment decisions"). *See City of Charlottesville v. FERC*, 661 F.2d 945, 953-54 (D.C. Cir. 1981) (rejecting award of an incentive treatment where the factual record did not demonstrate that level of investment had changed as a result of the incentive policy); *Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966, 974 (9th Cir. 2018) ("*CPUC 2018*") ("An incentive cannot 'induce' behavior that is already legally mandated."); *see also* 1992 Policy Statement at 61,594.

[96] *See, e.g., Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) ("*CPUC 2004*") (Emphasizing that "the incentives amounted to a small portion of total energy costs and are greatly outweighed by the benefits the customers will receive.").

and the 2012 Policy Statement (PP 10, 16) rightly require the total package of incentives to be tailored to address demonstrable risks and challenges faced by the applicant.

In contrast, a benefits-based approach would sever the nexus test's essential tether to Section 219's focus on awarding incentives necessary to *promote* development, yielding incentive outcomes exceeding those available under the current approach that are not rationally related to the statute's goal of inducing investment. Instead, the resulting "'bonus[es]' for good behavior"—an outcome rightly found unacceptable in Order 679 (P 26)—would invite a form of value of service pricing that is contrary to just and reasonable standard.[97]

A benefits-based approach also drives the need for symmetrical incentives—if good behavior is to be rewarded with upward ROE adjustments, bad behavior merits a downward adjustment. Symmetrical incentives were contemplated by the 1992 Policy Statement,[98] and are necessary to avoid excessively burdening consumers or arbitrarily relying on an unfounded assumption that all TOs are performing at or above average. While the Commission declined to provide for symmetry when it adopted the risks and challenges approach,[99] if it were to abandon that approach symmetrical incentives would be necessary to balance consumer and investor interests.[100]

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[97] *See W. Sys. Power Pool*, 55 FERC ¶ 61,099, at 61,316 & n.64 (1991) ("[V]alue of service pricing . . . is the hallmark of a monopoly.") (citing James C. Bonbright, *Principles of Public Utility Rates* 88-89 (Columbia University Press 1966)).

[98] 1992 Policy Statement at 61,606-07.

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

[100] Providing incentives that operate as a two-way street will be necessary to temper the otherwise perverse incentive that a benefits- (or characteristics-) based approach could create. *See* subpart c.

b) Benefits-based incentives undermine long-standing Commission initiatives required to ensure just, reasonable and not unduly discriminatory rates

For more than a decade the Commission has worked to develop and enhance regional planning processes to ensure just and reasonable rates and prevent undue discrimination. It recognized the opportunity for undue discrimination in the absence of Order 890's open, transparent, and collaborative planning process,[101] as well as the continued opportunities for discrimination and potential for unjust and unreasonable rates in the absence of the Order 1000's regional planning process.[102] It found that given significant transmission investments being made, regional planning and interregional coordination are needed to ensure the most cost-effective and efficient projects get built,[103] i.e., "the *right* transmission facilities."[104]

For even longer, the Commission has encouraged formation of RTOs that have ultimate responsibility for planning and expansion "to ensure a least cost outcome that maintains or improves existing reliability levels" and least cost solutions to congestion that imposes significant costs warranting mitigation, while coordinating with state authorities having responsibility over siting.[105] The Commission viewed "independent governance of the RTO [as] a necessary condition for nondiscriminatory and efficient

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

[102] *Id.* PP 42-50, 58-59.

[103] Order 1000 PP 42-50. Order 679-A and the 2012 Policy Statement also rightly recognize the value of the regional process in evaluating alternatives (through the rebuttable presumption and the expectation of a demonstration of consideration of alternatives). *See* response to Q 2.

[104] Order 1000 P 50 (emphasis added).

[105] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, at 31,164 (1999) ("Order 2000"), *order on reh'g*, Order No. 2000-A, 90 FERC ¶ 61,201 (2000), *appeal dismissed for want of standing sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). *See also* 18 C.F.R. § 35.34(k)(7).

planning and expansion,"[106] and recognized the efficiencies and benefits of a single entity performing this function with a regional view.[107]

An incentives system based on direct Commission evaluation of the expected benefits of individual projects in isolation would be a giant step backward. The Commission has previously found that the evaluation of proposed projects requires resolution of complex factual and modeling issues, including assessment under a range of stakeholder-vetted scenarios of benefits, costs, and alternative transmission and non-transmission solutions.[108] Piecemeal consideration of the benefits of individual projects requesting incentives would substitute a contentious Commission litigation (likely requiring an evidentiary hearing) that short-changes crucial factors that are best developed through a robust planning process. As a result, benefits-based above-cost returns may be awarded projects that are more costly, less cost efficient or effective, and designed to favor the TO's own load or generation.

c) Rewarding claimed benefits removed from Commission-approved planning processes runs contrary to Section 217

Section 217(b)(4) requires the Commission to exercise its authority under the FPA to facilitate the planning and expansion of the grid to meet the reasonable needs of LSEs, including TDUs. The Commission has found adoption of the Order 890 and Order 1000 planning processes to be consistent with its duties under this provision,[109] which

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[106] Order 2000 at 31,165.

[107] *Id.* at 31,082-83, 31,165.

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

[109] Order 1000 P 169 & n.231 (citing Order 890-A P 172).

"creates a requirement for the Commission."[110] As discussed in subpart b, to the extent an expected benefits-based incentives system awards above-cost incentives to projects that have not been selected in those planning processes, it undermines transmission planning in conflict with Section 217(b)(4).

A benefits-based approach could also conflict with Section 217(b)(4) by incenting Transmission Providers ("TPs") to delay needed upgrades. TPs have long been required to plan and expand the grid, consistent with good utility practice, to comparably meet the need of network customers,[111] a requirement buttressed by tariff requirements intended to give the TP skin in the game.[112] Benefits-based incentives based on piecemeal project evaluation could financially reward the opposite, incenting TPs to delay "business as usual" investments, and then claim that its overdue projects provide a range of benefits warranting incentives (e.g., economic, flexibility, access to new generation, addressing persistent congestion). While this may be less of an issue where RTOs independently assess system needs and are able to direct upgrades, the Commission should not violate Section 217(b)(4)'s directive by rewarding TPs that have failed to plan and expand their system to meet the reasonable needs of LSEs on a timely basis.

d) An incentives system based on Commission evaluation of benefits, disconnected from planning, may impede siting

A benefits-based regimen would put the Commission in the position of picking winners and losers among projects that may well have been competing alternatives in a

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

[111] *Pro Forma* OATT § 28.2.

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

regional planning process.[113] Or worse, the Commission could make them all "winners" (with hefty incentive ROE price tags) that proceed through state siting processes, even though constructing them all makes no sense from a planning perspective—fueling anti-siting sentiments, overwhelming and alienating state siting authorities, and making it less likely that the most effective and efficient project will be approved. The benefits identified as the basis for above-cost incentives may align poorly with state siting agency requirements or attitudes, providing fodder to siting opponents[114] and complicating siting. Such approach could *create* an environment in which construction of new transmission is harder, more contentious, and riskier, contrary to Section 219's goals.

e) A benefits-based approach to incentives comes with other significant drawbacks

As discussed in response to Q 5, eliminating the risks and challenges framework in favor of a benefits-based approach must overcome legal, policy, and practical challenges, all of which argue against making such a change. For example, where incentives are based on Commission evaluation of benefits, the benefits calculation becomes central to the incentives determination. Challenges include the need to identify and quantify amorphous and potentially overlapping benefits, and to exclude from the evaluation benefits associated with required upgrades for which no inducement is necessary or appropriate, all outside the context of the regional planning process. The Commission's 1992 Policy Statement calls for quantification of consumer benefits to

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[113] *Cf.* Order 679 P 298 (adopts case-by-case review to avoid putting the Commission in a position to pick winners and losers among technologies).

[114] ROE incentives may also incite grass roots opposition. *See, e.g.*, Soul of Wisconsin, *Understanding the Consequences and Responses to Wisconsin's Utilities Excessive Spending* (2015) http://stoppathwv.com/stoppath-wv-blog/investor-owned-utilities-hope-to-make-big-bucks-buying-wind-farms-and-building-transmission-lines; http://soulwisconsin.org/Documents/Understanding%20Consequences%20of%20Utility%20Debt_V04.pdf.

allow assessment of their value and the prospects for the benefit occurring, and to protect consumer interests as the FPA requires.[115] Although not required under Order 679's risks and challenges approach, adherence to the 1992 Policy Statement's quantification requirements takes on far greater importance if the Commission awards incentives based on evaluation of claimed benefits.

Similarly, consistent with treating consumer benefits as a threshold requirement under the risks and challenges approach, the Commission focused on accountability and reporting requirements on whether the project got built,[116] and did not require reporting on actual consumer benefits.[117] Where incentives are based on benefits, accountability and reporting requirements cannot ignore benefits or actual costs.

Resolution of such difficult and complex factual and modeling issues will necessitate an opportunity for evidentiary hearings (with discovery) to avoid arbitrary determinations. None of this will help achieve Section 219's goals of promoting investment in projects that benefit consumers.

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?

If the Commission adopts a benefits-based approach, it needs to provide guidance limiting the projects for which it will consider incentives and as to how it will evaluate the benefits from those projects, as well as the level and combination of incentives warranted. In addition to commenting on specific objectives identified in the NOI, TAPS

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[115] 1992 Policy Statement at 61,590, 61,600.

[116] Order 679 P 367 (establishing Form 730).

[117] *Id.* P 371. Applicants must propose (*id.* PP 279, 373) and the Commission will set accountability metrics to ensure consumer benefits are justified on an on-going basis. *Id*. P 119.

provides some ground rules that—while not sufficient for reasons discussed in response to Q 4—would be necessary for such incentives to be consistent with Section 219.

- The Commission should not provide above-cost incentives for investments that TOs already have an obligation to make, and should limit such incentives to truly exemplary voluntary projects.

- Benefits must be calculated in relation to costs, which must be confirmed before ROE incentives are implemented.

- Benefits claimed as the basis for incentives must be clearly defined and quantified, with the applicant bearing the burden of proof on the level of claimed benefits and projected costs.

- Incentives should be restricted to no more than ten years.

- If the Commission declines to restrict incentives to no more than ten years, any benefits-based incentives regimen must include accountability for claimed project benefits and costs.

- The Commission should put in place measures to protect consumers from the cost of excessive incentives.

- To ensure that only cost-effective and efficient projects receive incentives, any benefits-based incentives system must respect and support the Order 1000 and Order 890 planning processes by:

    1. Requiring full participation and selection in applicable planning processes as a prerequisite for receipt of any benefits-based incentives; and

    2. Leveraging existing Commission-approved methodologies for quantifying benefits and costs that are part of applicable Order 890/1000 processes.

- The Commission should state definitively that an applicant's openness to joint ownership is relevant to its eligibility for incentives, and that when an applicant has not been open to such arrangements, there will be a rebuttable presumption that it has not taken all appropriate steps to minimize its risks.

a) The Commission should not provide benefits-based incentives for required investments

Section 219 incentives must be an inducement to voluntary action. As recently affirmed by the Ninth Circuit, "[a]n incentive cannot 'induce' behavior that is already legally mandated."[118] Consistent with this guidance, while Order 679 did not categorically disqualify mandatory projects from risks and challenges-based incentives if an applicant demonstrates nexus (recognizing the relevance of such mandate to establishing nexus),[119] if the Commission departs from that approach it should make clear that no benefits-based incentives will be granted for mandatory projects. Otherwise, the Commission would be awarding TOs real economic profits, above and beyond the base ROE, for doing exactly what they are required to do. Such an unjustified generic rate increase has nothing to do with the purpose of Section 219 and its requirement that rates be just and reasonable. Benefits-based incentives, particularly ROE incentives, should be reserved for exemplary, voluntary projects.

For example, benefits-based incentives should not be granted for projects required to meet mandatory reliability standards established pursuant to FPA Section 215.[120] Avoidance of penalties of up to $1 million per violation per day should be ample incentive for TOs/TPs to adhere to NERC requirements. Recognizing reliability is a core objective of Section 219,[121] the NOI (P 22) correctly states: "Transmission Owners are already required to address many facets of reliability through compliance with . . . NERC

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[118] *See CPUC 2018*, 879 F.3d at 973-74 (the Commission acted arbitrarily in granting incentive for continued RTO participation without inquiring into voluntariness of RTO membership). *See also New England Power Pool*, 97 FERC ¶ 61,093 (2001) (incentive denied to avoid "unjustly reward[ing] NEP for doing what it is supposed to do i.e., to adequately maintain its facilities in a prudent, cost-effective manner."), *order on reh'g*, 98 FERC ¶ 61,249 (2002).

[119] Order 679-A P 122. *See also* Order 679 P 94 (routine investments to comply with reliability standards "have, as a general matter, been adequately addressed through traditional ratemaking because there is an obligation to construct them and high assurance of recovery of the related costs. For these and other reasons, traditional ROE determinations may continue to be appropriate for these investments.").

[120] 16 U.S.C. § 824o ("Section 215").

[121] Section 219(b)(4)(A) directs the Commission to "allow recovery of . . . all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215."

. . . reliability standards and various other planning criteria." Thus, incentives are not appropriate for projects designed to meet those standards or state requirements.[122]

As noted in response to Q 4, TPs have long been required to expand the system to provide requested transmission and interconnection service on a non-discriminatory basis.[123] TPs are also required to plan and expand the grid, consistent with good utility practice, to comparably deliver a network customer's network resources to its network load.[124] Projects required to meet tariff requirements should not give rise to incentives.

Similarly, for an RTO to perform its required planning and expansion function, TOs that join RTOs must commit to undertake certain transmission system expansions when directed by the RTO,[125] thus making incentives unnecessary for such projects.[126]

Nor should ancillary benefits associated with projects required for other purposes be considered in granting incentives. For example, as Order 679 recognized, reliability projects can have economic impacts.[127] If the Commission allows incentives based on the economic benefits of a project required to meet reliability standards, it will have

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[122] Section 215(i)(3) expressly recognizes and preserves that state authority with respect to safety, adequacy and reliability of electric service within that state.

[123] *Pro Forma* OATT § 15.4 (Large Generator Interconnection Agreement ("LGIA")), Articles 11.3 and 11.4.1.

[124] *Pro Forma* OATT § 28.2.

[125] *See* 18 C.F.R. § 28.34(k)(7).

[126] The D.C. Circuit upheld pre-Order 679 ROE incentives based on a factual record showing the incentive would induce ISO-NE TOs to accelerate the projects, which acceleration would deliver "dramatic" quantified savings; consistent with this focus, incentives were limited to projects completed by a specified date. *Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30, 33-36 (D.C. Cir. 2010). The court found that Commission's determination satisfied the rationally related "nexus" test based on uncontested findings of "exceptional value" given congestion and unreliability that produced a sense of urgency linked to the incentive. Because of the need to accelerate these projects, the court distinguished these essentially performance-based incentives from rewarding utilities for doing what they are supposed to do anyway, as barred by *New England Power Pool*, 97 FERC ¶ 61,093 (2001).

[127] *See*, *e.g.*, Order 679 PP 37-41, 344.

improperly granted incentives for a mandatory project. Similarly, an addition required to meet transmission and interconnection service requests may reduce congestion, but should not qualify for incentives because such additions are mandatory under the OATT.

Likewise, the Commission should require an applicant to demonstrate that it is not merely tweaking a mandatory project to qualify for incentives, even though the bulk of the cost is associated with a mandatory investment. To prevent gaming, any claim for incentives for a project whose purposes include satisfying reliability, tariff, or other requirements must be limited to benefits from incremental additions to the required project, with the incentive applied only to that incremental investment.

More generally, consistent with the 2012 Policy Statement [128] and decisions issued under Order 679,[129] benefits-based incentives should be restricted to projects that are not "business as usual." They should be limited to voluntary projects that deliver extraordinary benefits.

b) Benefits must be calculated in relation to costs, which must be confirmed before incentives are implemented.

Absent consideration of the project's costs (including any cost-increasing incentive to be requested), there is no assurance that consumers will benefit from the project, as Section 219 expressly requires. *See* response to Q 8. The actual costs should be confirmed before incentives are implemented to ensure that claimed benefits are delivered, rather than eroded by cost-overruns. Such approach is consistent with the Commission's denial of implementation of incentives granted to an inter-regional project

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[128] 2012 Policy Statement PP 20-22.

[129] *E.g.*, *Baltimore Gas & Elec. Co*., 120 FERC ¶ 61,084, PP 52-53 (2007).

that failed to obtain approval in the second region.[130] Requiring a separate Section 205[131] filing to confirm qualification for receipt of an incentive is also consistent with the Commission's approach to the abandoned plant incentive.[132]

Thus, as discussed in response to Q 85, before incentives are implemented, the applicant must make a Section 205 filing that includes the project's final, actual costs (including incentives) and demonstrates, using the benefits calculation on which the Commission provisionally awarded incentives, that the project achieves the benefits-to-cost ratio assumed in the grant of incentives. If the actual project costs exceed the estimate used to award the incentives, the incentives should be rescinded or reduced.

Further, the Commission should adhere to its requirement that no incentives may apply to above-budget costs, consistent with the 2012 Policy Statement (P 28). *See also PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,097, P 86 (2016) ("an applicant is expected to commit to limit the application of such incentive ROE adder to a cost estimate").

c) Benefits must be clearly defined and quantified

To be considered for incentives, benefits claimed should be clearly identified and quantified, with all assumptions made transparent and supported. Doing so is required to enable the Commission and stakeholders to meaningfully evaluate claimed benefits to ensure that the project comes within the ambit of Section 219 and that the incentive's cost is outweighed by the consumer benefits,[133] consistent with the FPA and the 1992 Policy

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[130] *See Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, PP 52-55 (2018) (denying implementation of previously awarded ROE incentives for project anticipated to span the PJM-MISO border that was unable to secure PJM approval).

[131] 16 U.S.C. § 824(d) ("Section 205").

[132] *See* response to Q 79.

[133] *CPUC 2004*, 367 F.3d at 929.

Statement.[134] Quantification is required to provide a basis for verifying that the benefits materialize, to hold applicants accountable, and prevent unjust enrichment. *See* subpart e and responses to Q 86-89 and Q 98-105.

Quantification will not be easy. The challenges of estimating benefits of long-lived transmission projects in the context of a changing generation mix, evolving grid, and changes in load are complicated not only by the need to exclude benefits associated with the mandatory aspects of a project, but also by the overlapping nature of various incentive objectives identified in the NOI and the claimed difficulty of separating incremental benefits from gold-plating. An applicant may well claim multiple benefits (e.g., enhanced reliability, economic efficiency, persistent geographic needs, flexibility, resilience connecting new generation, more efficient operation of existing transmission), adding significant complexity to calculating and evaluating benefits. Even the more quantifiable benefits (e.g., economic efficiency) are projections relying on assumptions that are open to challenge. More qualitative claimed benefits (e.g., enhanced reliability, security, resilience, flexibility, improving existing transmission facilities) are even harder to assess and quantify. As the 1992 Policy Statement, which called for quantification of claimed benefits to protect consumers,[135] made clear: "Vague statements such as 'increased system reliability' are not acceptable."[136]

Evaluation of claimed benefits will require resolution of complex factual questions, tradeoffs, uncertainty over long time horizons, and modeling controversies

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[134] *See* response to Q 4 subparts a, e; 1992 Policy Statement at 61,590, 61,600-01.

[135] 1992 Policy Statement at 61,590, 61,600-61.

[136] *Id.* at 61,601.

regarding planning the regional grid that the Commission is not well-positioned to address. Recognizing the complexity, Order 1000 left these issues to the regional transmission planning process and made clear it was not dictating planning outcomes or even requiring filing of regional plans.[137] In contrast, an incentives regimen based on direct Commission evaluation of the benefits of individual projects would insert the Commission into the center of these issues—all based on a record that, in the absence of benefits calculations from an Order 1000 or robust Order 890 planning process that uses a consistent, Commission-approved methodology to quantify project benefits and costs (*see* subpart g), is focused on *ad hoc*, difficult-to-confirm (and likely to be contentious) applicant calculations of claimed benefits.

Thus, as discussed in response to Q 4, an evidentiary hearing with discovery will likely be required to resolve material factual and modeling issues inherent in evaluating and quantifying benefits. Absent such definition and quantification, the Commission will have disabled itself from fulfilling its FPA obligations.

d) Incentives should be restricted to no more than ten years

Nothing in Section 219 assures incentives for the life of the project. Nor is there any demonstration that investors require incentives extending beyond ten years as an inducement. As discussed in response to Q 1, there is every indication that the widespread availability of formula rates, assuring cost recovery with a Commission-regulated ROE, is more than ample inducement of transmission investment. To balance

[137] Order 1000 P 50 ("Transmission planning is a complex process that requires consideration of a broad range of factors and an assessment of their significance over a period that can extend from present out to 20, 30 years or more in the future. In addition, the development of transmission facilities can involve long lead times and complex problems related to design, siting, permitting, and financing"); Order 1000-A P 285.

investor and consumer interests, and mitigate excessive incentive awards, the duration of ROE incentives should be limited to no more than ten years. *See* response to Q 83-84.

The need to restrict incentives to no more than ten years is heightened if the Commission allows benefits-based incentives. Given the difficulty calculating benefits in the context of the changing nature of the grid, generation mix, and loads, as time advances the benefits on which incentives were based become more speculative and divergent from reality. Restricting incentives to no more than ten years will allow the benefits evaluation to focus on near-term horizon where there is greater certainty.

e) If incentives are not restricted to ten years, the Commission must periodically re-test and hold applicants accountable for claimed benefits

If the Commission does not restrict benefits-based incentives to ten years, it should periodically test whether the project is actually delivering the claimed benefits on which the incentives are premised. *See* response to Q 86-89. And it should do so in relation to the project's actual costs. *See* subpart b and response to Q 8.

If the promised benefits do not materialize or remain at the promised level (or if the actual costs exceed those projected), the incentive must be terminated or reduced to maintain the integrity of the process. The Commission has previously denied implementation of ROE incentives where the factual predicate for the incentives grant was not achieved.[138] Failing to revoke incentives where the basis on which they were awarded no longer obtains would be inconsistent the Commission's approach to other

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

grants, e.g., market-based rates ("MBR");[139] standard of conduct waivers.[140] Absent such accountability, a benefits-based incentive regimen would be unjust and arbitrary.

f) The Commission should put in place measures to protect consumers from excessive incentives

As discussed in response to Q 4 subpart a, a benefits-based approach drives the need for symmetrical incentives—if good behavior is to be rewarded with upward ROE adjustments, bad behavior merits a downward adjustment. In addition, adoption of a benefits-based incentive regimen should not be a license to grant unnecessary and excessive incentives contrary to Section 219(d)'s requirements that the resulting rates be just and reasonable. Key elements from the 2012 Policy Statement should be retained. For example, the Commission should continue to require applicants to use risk-reducing incentives and measures before seeking enhanced returns, and take them into account in evaluating the total package of incentives;[141] the Commission cannot rationally find the ROE incentive just and reasonable without considering the impact on ROE of risk-reducing incentives.[142] And it would be unjust and unreasonable to award ROE

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

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

[141] 2012 Policy Statement PP 10, 16.

[142] *See* Order 679-A P 27. *See, e.g.*, *S. Cal. Edison Co.*, 112 FERC ¶ 61,014, P 61 & n.49 (2005) (100% recovery of abandoned plant may warrant a reduced ROE).

incentives where the applicant had not taken prudent actions to minimize risks (including offering joint ownership, as discussed in Part II).[143]

Finally, the Commission should place a cap on total project-based incentives. *See* response to Q 97.

g) Any benefits-based incentives system must respect and support the Order 1000 and Order 890 planning processes

If the Commission moves to a benefits-based approach to awarding incentives, it should adopt criteria that respect and support the Order 890 and Order 1000 planning processes. These processes seek to select the best projects by comparing them against transmission and non-transmission alternatives, and—in the case of certain Order 890 processes and all Order 1000 processes—use a consistent, Commission-approved methodology to quantify project benefits and costs.

Any benefits-based approach should leverage these existing planning processes and methodologies, rather than create a separate, inconsistent system of financial inducements that promotes construction of projects that are neither efficient nor cost-effective. Transmission assets are long-lived and capital-intensive, but major resource and non-transmission technology transformations underway make the future grid's needs uncertain. Open, transparent, and collaborative transmission planning processes that consider regional trends and deployment of evolving technologies, and support multiple alternative futures by developing a plan that would be robust under most, if not all, futures—a "no regrets" approach[144]—are crucial to avoiding large stranded costs and

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[143] Order 679-A P 24.

[144] This multi-scenario planning approach was used in the 2005 CapX2020 Vision Study that became the basis for major new transmission infrastructure projects that are being constructed in the northern Midwest. *See* Marta C. Monti, et al., *Transmission Planning and CapX2020: Building Trust to Build Regional*

gold-plated upgrades that favor the TO's long-term generation plans at the expense of transmission projects that benefit all loads and resources.

To the extent existing planning processes and their benefit evaluation methodologies need improvement, the Commission should strengthen them—not undermine long-standing efforts to promote rational grid expansion.

(1) Planning-related principles for Order 1000-eligible projects

In cases where the transmission project for which incentives are sought would qualify to be considered for selection in the regional plan for regional or interregional cost allocation, the Commission should not grant incentives—particularly ROE incentives—unless the project has gone through the applicable planning process *and* has been selected. Each region has established its own criteria for projects that can be considered for regional and interregional cost allocation. Awarding incentives to projects that qualify for, but choose to evade, consideration in the regional planning process is a step in the wrong direction.[145] It will undermine transmission planning by hollowing out the range of alternatives presented to planners. And it will incent construction of expensive projects that have *not* been identified as the most cost-effective and efficient means of meeting regional and interregional needs. A TO's unwillingness to submit its

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Transmission Systems at 19-24, U. Minn. Humphrey School of Public Affairs (2016), https://www.hhh.umn.edu/sites/hhh.umn.edu/files/capx2020_final_report.pdf.

[145] For example, Florida's Order 1000 process only considers projects for selection in the regional plan for regional cost allocation if the TO chooses to request that consideration. *See Tampa Elec. Co.*, 143 FERC ¶ 61,254, P 113 (2013). A TO that chooses not to subject its otherwise qualifying project to the Order 1000 process, thus limiting evaluation of the project to its own Order 890 process, should not be eligible for incentives.

project to the scrutiny of the regional planning process is an indication that it may well be inferior to alternatives, or unduly favor its own generation and load.[146]

The Commission should not grant benefits-based incentives—particularly above-cost incentives—to projects that have not been selected as the most cost-effective and efficient. Although Order 679 and the 2012 Policy Statement linked eligibility for incentives to *evaluation* in a planning process, they did not condition project-based incentives on *selection* in a planning process.[147] But much has changed since that time. In ruling that incentives would not be limited to projects that result from regional planning, Order 679-A (P 111) noted that "many utilities are in regions in which no formal regional planning process exists at this time." The 2012 Policy Statement was issued before the Commission had ruled on any of the Order 1000 compliance filings. Today, in contrast, every region has a Commission-approved planning process and the experience of multiple regional planning cycles. Most important, any system that awards incentives based on projected benefits (as opposed to the risks and challenges framework) depends heavily on accurate, consistent estimates of those benefits. The existing link to planning must be strengthened if the Commission shifts to benefits-based incentives.

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[146] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,078, FERC Stats. & Regs. ¶ 31,036, at 31,682 ("inherent characteristics of monopolists make it inevitable that they will act in their own self-interests to the detriment of others") ("Order 888"), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 78 FERC ¶ 61,220, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998*), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000*), aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). While the Order 890 process provides some necessary transparency, that process still allows an opportunity for transmission provider/transmission owner discrimination. *See* Order 1000 PP 58-59.

[147] Order 679 PP 58, 345; Order 679-A P 111; 2012 Policy Statement PP 25, 26 n.35.

In addition to requiring that projects fully participate in the applicable regional planning process as a prerequisite to receiving incentives, the Commission should leverage the existing benefits-evaluation methodologies of those planning processes. Thus, the Commission should limit the benefits claimed by incentives applicants to those quantified through an open, transparent Order 1000 planning process in which alternatives were considered and evaluated.

If the benefits-evaluation methodology used in a regional process is inadequate, the appropriate response is to revisit and improve it. MISO and SPP, for example, recently submitted a proposal to eliminate unnecessary obstacles to project selection in their interregional coordination process.[148] Their filings—a response to the regions' experience with the first two Order 1000-compliant MISO-SPP coordination cycles—illustrate the potential for TPs to learn from and improve their regional and interregional processes, and the importance of giving those processes an opportunity to work.

If it is indeed too speculative to include a factor—e.g., production cost savings estimates—in the Order 1000 benefits-evaluation methodology for a particular region, [149] then that factor should not be used to justify benefits-based incentives either. Regardless, the Commission should not allow, let alone promote, creation of two different benefits-

[148] *See* MISO, Revisions to SPP-MISO Joint Operating Agreement to Enhance the Coordinated System Planning Process, *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER19-1895-000 (May 17, 2019), eLibrary No. 20190517-5182; SPP, Revisions to SPP-MISO Joint Operating Agreement to Enhance the Coordinated System Planning Process, *Sw. Power Pool, Inc.*, Docket No. ER19-1896-000 (May 17, 2019), eLibrary No. 20190517-5185. The Commission directed, and MISO and PJM have implemented, similar changes to the MISO-PJM interregional coordination process. *See N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,058, PP 131-32 (2016), *on reh'g*, 158 FERC ¶ 61,049, P 41 (2017).

[149] Florida's Order 1000 process, for example, does not consider production cost savings as part of its evaluation of economic transmission projects: the region's TPs argued it was too speculative and divisive to incorporate that factor, and the Commission declined to require it. *Tampa Elec. Co.*, 148 FERC ¶ 61,172, PP 90, 405, 425 (2014).

evaluation methodologies: one that allows a TO to understate the benefits of a project in Order 1000 planning processes, and a second that simultaneously allows it to inflate those benefits to claim rate incentives.

Similarly, the Commission should only consider granting the benefits-based incentives that were included in the project costs disclosed and considered in the Order 1000 process for selecting projects for regional or interregional cost allocation. Transmission developers should be required to clearly state which incentives, if any, it plans to request from the Commission, so that the full consumer cost can be incorporated into the Order 1000 project analysis. Otherwise, the Commission is inviting a "bait and switch" in which the developer claims one set of project costs in the planning process, even though the actual costs will be significantly higher due to Commission-granted rate incentives. Such behavior is unacceptable; and it will eviscerate planning in regions that use a competitive bidding process to select projects and developers based on cost.

While the same methodologies should be used to quantify project benefits and costs for purposes of regional planning and any benefits-based incentives system, the criteria for eligibility under the two programs must be different. Order 1000 provides that regions cannot set a benefit-cost ratio higher than 1.25:1 as a criterion for selecting a project in the regional plan for regional cost allocation.[150] Granting benefits-based rate incentives to all such projects, including those with very limited net benefits, would be excessive—the equivalent of simply raising the base ROE for all projects. Thus, the Commission should only grant benefits-based ROE incentives after appropriate

[150] Order 1000 PP 586-87, 646, 648-49.

procedures (*see* responses to Q 5 subpart c and Q 7), and only if the benefits (in relation to costs) are extraordinary—far in excess of 1.25:1.

(2) Planning-related principles for projects not eligible under the applicable Order 1000 process

For transmission projects that do *not* qualify for consideration for regional cost allocation under the applicable Order 1000 process (e.g., based on voltage, scope, and other criteria defined by the particular regional planning process), full participation and selection in the applicable Order 890 planning process should be a prerequisite for any request for benefits-based incentives. Because Order 890 processes vary, the additional requirements and processes for granting benefits-based incentives must be tailored to the specific Order 890 process. Based on the experience of TAPS members, some TPs—particularly RTOs—have implemented Order 890 planning processes that quantify the benefits and costs of proposed projects using consistent, Commission-approved methodologies and select the best projects by comparing them against transmission and non-transmission alternatives. In contrast, other TPs—including some individual transmission owners within RTOs—present their transmission plans to stakeholders in an Order 890 process, but provide insufficient information to demonstrate consistency in quantifying projects benefits, enable stakeholders to replicate the TP's decisions, or ensure that transmission and non-transmission alternatives are adequately considered.[151]

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[151] *See, e.g.*, PJM, Compliance Filing in Response to Order Accepting in Part Proposed Tariff Revisions and Requiring Tariff Revisions Pursuant to Section 206, *PPL Elec. Utils. Corp.*, Docket No. ER17-179-000, *Monongahela Power Co.*, Docket No. EL16-71-000 (Mar. 19, 2018), eLibrary No. 20180319-5186. Although the Commission concluded that this compliance filing satisfied the requirements of Order 890, *Monongahela Power Co.*, 164 FERC ¶ 61,217 (2018), the process established by the PJM TOs for Supplemental Projects does not include any requirement or Commission-approved methodology to quantify benefits, and PJM does not exercise any authority to approve or decline Supplemental Projects planned by individual PJM TOs. The current planning process for PJM Supplemental Projects, therefore, is a "Minimalist 890 Process," notwithstanding the fact that PJM

Given these differences, one size will not fit all; so TAPS recommends creating two separate tracks for benefits-based incentive requests, depending on the rigor of the applicable Order 890 process. In addition, transmission projects that do not go through *any* Order-890 compliant planning process should be ineligible for incentives. The Commission, for example, recently held that projects that "do not increase the capacity of the grid"[152]—a category that "include[s] maintenance, repair, and replacement work, and infrastructure security, system reliability, and automation projects [the TO] undertakes to maintain its existing electric transmission system and meet regulatory compliance requirements"[153]—are not required to go through an Order 890 planning process. Such projects, many of which are mandatory, do not meet Section 219(b)(3)'s criterion of increasing the capacity of existing transmission facilities. They should be ineligible to receive benefits-based incentives.

890 Track 1- Robust 890 Processes. For projects that have been considered and selected in an Order 890 transmission planning process with a robust, Commission-approved methodology for quantifying benefits, the principles applicable to projects eligible for consideration in Order 1000 regional planning process should apply:

- No incentives for projects not selected by the applicable planning process for inclusion in the transmission plan.
- Project benefits claimed by the applicant for incentives may not exceed the project benefits quantified by the transmission planning process.

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administers a separate, more rigorous regional transmission planning process within the RTO's footprint.

[152] *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, P 72 (2018). *See also S. Cal. Edison Co.*, 164 FERC ¶ 61,160, P 37 (2018).

[153] *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, P 67 (2018). As discussed in responses to Q 5 subpart a and Q 7, the Commission should not grant benefits-based incentives to projects that are mandatory or fail Section 219(b)(3)'s criterion of increasing the capacity of existing transmission facilities.

- The Commission should not grant an incentive unless the applicant: (1) expressly disclosed in the planning process its intention to request the incentive from the Commission; and (2) provided the planning process with information necessary to incorporate the incentive's full cost into the project's evaluation.

- Benefits-based incentives should be reserved only for exceptional projects with extremely high benefit-cost ratios, and only granted after appropriate procedures (*see* responses to Q 5 subpart c and Q 7).

890 Track 2 – Minimalist 890 Processes. For projects that have only been considered in an Order 890 process that does *not* quantify benefits using a consistent, Commission-approved methodology and rigorously compare proposed projects to transmission and non-transmission alternatives, a different approach will be necessary. The Commission should be particularly skeptical of applicants claiming extraordinary benefits from projects that have not been vetted by an Order 890 planning process with a robust, consistent benefits-quantification methodology and information-sharing sufficient to enable stakeholders to replicate the TP's decisions. Such applicants will be relying on *ad hoc* benefits analyses to support their requests, which will be difficult, if not impossible, for the Commission to evaluate in a consistent fashion.

While the Commission found that requiring Order 890 planning processes was consistent with the directives of FPA Section 217(b)(4),[154] it also recognized that Order 890 processes (as compared with Order 1000 processes) provide greater opportunity for undue discrimination in the scope of the project and its benefits, and for failing to fully consider and plan for the reasonable needs of all LSEs, as Section 217(b)(4) mandates.[155] To avoid awarding incentives to projects planned on an unduly discriminatory basis, the Commission must incorporate safeguards into its evaluation of any benefits-based rate

[154] Order 890 PP 79 n.72, 436.

[155] Order 1000 PP 58-59.

incentives for projects emerging from minimalist Order 890 processes, to assure that TDUs are not being saddled with excess costs to support facilities designed and built to benefit the TO's own loads while TDU needs remain unmet.

In light of these fact-intensive issues, the Commission should place a high bar for awarding benefits-based incentives to such projects, and cannot short-cut FPA procedures for such requests. The incentives applicant must bear the burden of proof.[156] To provide ratepayers and the Commission with an adequate opportunity to understand and challenge such analyses, case-by-case adjudication, including opportunities for discovery and cross-examination, will be required.[157]

h) The Commission should strengthen the encouragement of joint ownership.

As discussed in Part II, requiring incentive applicants to offer joint transmission ownership to TDUs on a load-ratio-share basis is crucial to preventing abuses that may result in unjust, unreasonable, and unduly discriminatory rates. And it can help mitigate the impacts on TDUs from incentive-inflated rates. The Commission should strengthen its encouragement by stating definitively that evidence of an incentive applicant's openness to joint ownership is relevant to its eligibility for incentives, and that when an applicant has not been open to such arrangements, there will be a rebuttable presumption that it has not taken all appropriate steps to minimize its risks.

Q 6) How would a direct evaluation of expected benefits, instead of using risks and challenges as a

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[156] As discussed in n.84, *supra*, Order 679-A established a limited rebuttable presumption that a project has consumer benefits in certain limited circumstances. While that rebuttable presumption may be appropriate under a risk-and-challenges framework, a benefits-based incentive system requires a demonstration of the *quantity* of the project's benefits. Therefore, in a benefits-based incentive approach, a rebuttable presumption that shifts the evidentiary burden to ratepayers would be inappropriate and contrary to the requirements of the FPA.

[157] *See* responses to Q 5 subpart c and Q 7.

proxy, impact certainty for project developers?

An incentives system based on direct evaluation by the Commission of expected project benefits is likely to produce less certainty as to timing and outcome than the existing approach.[158] Given the challenges of quantifying benefits, benefits-based incentives will require more extensive Commissioner analyses and longer proceedings (with the potential for evidentiary hearings in the event of material issues of fact), both upfront and upon implementation. *See* responses to Q 5 subparts b, e and Q 85-89.

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 automatically award incentives. Section 219(d) provides: "All rates approved under the rules adopted pursuant to this section . . . are subject to the requirements of sections 205 and 206 that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential." While "non-cost factors may legitimate a departure from a rigid, cost-based approach . . . when FERC chooses to refer to non-cost factors in ratesetting, it must specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates." *Farmers Union*, 734 F.2d at 1502. Automatic incentives would bypass the "reasoned consideration to each of the pertinent factors," *id.*, and cannot be squared with FPA obligations.

First, automatic incentives will not allow the Commission to ensure that a project provides a level of benefits warranting incentives—i.e., far beyond what can be expected from required projects. *See* response to Q 5 subpart a. Bright line criteria will not

[158] *See* Order 679 P 77 (Commission will strive for action within 60 days on requests for incentives under risks and challenges approach).

suffice; they will be unable to keep pace with changes in technology, accommodate regional differences with respect to particular needs, conditions, and quantification methodologies used in Order 890 and Order 1000 processes. Given the significant rate impacts and difficulty of quantifying benefits with the precision necessary to ensure just and reasonable rates, a benefits-based approach requires case-by-case review, and increases the likelihood that an evidentiary hearing with discovery will be necessary to resolve factual and modeling issues.

Second, as discussed in response to Q 4, the FPA requires more than an analysis of whether a project increases reliability or reduces congestion. Section 219 and long-standing precedent require the Commission to assess whether the requested incentive is needed to induce action, and is no greater than necessary.[159] The Commission rightly found the nexus test necessary to ensure "there [is] a relationship between the rate treatments sought and the attraction of new capital," Order No. 679-A P 21, and "incentives are not provided in circumstances where they do not materially affect investment decisions," *id.* P 25.

Evaluation of whether and what incentives are needed to induce investment is fact-specific. The level and the duration of incentives must be considered and appropriately limited.[160] Among other things, voluntariness must be assessed,[161] as well as the portion (if any) of the investment to which the incentive applies.[162] Automatic

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[159] *See* precedent discussed in response to Q 4 subpart a. *See also* 1992 Policy Statement at 61,902 (when providing incentives the Commission must ensure "there is a correlation between the incentive and the result to be induced.").

[160] *See* response to Q 83-84.

[161] *See CPUC 2018*, 879 F.3d at 974.

[162] *See* response to Q 5 subpart a.

incentives would improperly bypass these crucial inquiries, "simply increasing rates in a manner that has no correlation to encouraging new investment." Order No. 679 P 6.

Third, automatic incentives would violate Section 219(d)'s requirement that rates resulting from incentives be just and reasonable. Case-by-case evaluation, consistent with the procedures normally attendant to rate-setting, is required to enable the Commission to "examine the total package of incentives being sought [and] the inter-relationship between any incentives." Order 679-A P 21. The limitations the Commission has placed on formula rates[163] highlight the lack of justification for departing from fundamental FPA protections in granting incentives.

Whether a rate that includes incentives is just and reasonable depends on the facts and circumstances and other incentives sought. An ROE incentive award within the cap on ROE incentives (*see* response to Q 97) may not be reasonable for a particular project given the impact on required ROE of risk-reducing incentives[164] or if an applicant fails to take risk reducing measures. As the Commission has recognized, "an ROE incentive is

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[163] The Commission reviews each rate formula in the context of the specific TP's circumstances, or, in regions with footprint-wide formulas, the circumstances pertaining to all TOs operating in that footprint. Annual inputs are based on well-established ratemaking principles, case law, and Commission guidance on the elements includable in cost-of-service rates, drawn from Form 1 filings subject to Uniform System of Accounts (or projections of those costs, subject to true-up), or are subject to change only on Commission review (e.g., ROE, depreciation). Formula rate inputs are subject to protocols required and approved by the Commission, *see, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,127, P 9 (2012) ("Because the formula rates . . . do not typically require transmission owners to make a section 205 filing to update their annual transmission revenue requirement, safeguards need to be in place to ensure that the input data is the correct data, that calculations are performed consistent with the formula, that the costs to be recovered in the formula rate are reasonable and were prudently incurred, and that the rates are just and reasonable. The safeguard that has often been employed is formula rate protocols.") (footnote omitted); *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343, P 7 (2015) (requiring protocols to address inadequacy of transparency and challenge procedures). As a result, the Commission and the public can have reasonable confidence that a formula rate will produce just and reasonable rates.

[164] *See, e.g., S. Cal. Edison Co.*, 112 FERC ¶ 61,014, P 61 & n.49 (2005) (100% recovery of abandoned plant may warrant a reduced ROE).

not susceptible to a precise calculation. Rather, the incentive is based on a range of reasonable ROEs, which takes into account a number of factors that may be both cost-related and policy-related." *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265, P 71, *clarified*, 124 FERC ¶ 61,136 (2008). Automatic incentives could not accommodate such a review, and would excuse an applicant from its burden to demonstrate the incentives are just and reasonable.[165]

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?

Varying incentives based on the size of expected benefits is particularly hazardous given the challenges of estimating benefits far into the future where there will be significant changes in the grid and our resource mix. If incentives are granted on the basis of evaluation of benefits, the project's associated costs must also be considered (as well as alternatives) to ensure that the project actually delivers net consumer benefits consistent with the purpose of Section 219. Otherwise, the Commission could well be providing incentives for large and unduly expensive projects that have a net negative value. This is especially a concern if the Commission grants benefits-based incentives on projects not selected as most cost effective and efficient through the Order 1000 process—disabling the Commission from leveraging a regional process that considers the project's benefits and costs against alternatives—or through a robust Order 890 process with a consistent, Commission-approved benefits evaluation methodology.

In confronting what was then "a national problem—the decline in transmission investment that is threatening reliability and imposing billions of dollars of congestion

[165] *See* 16 U.S.C. § 824d(e). *See also* Order 679 P 43 (The Commission will require applicant to justify its incentives on a case-by-case basis, and rate impacts will be considered be evaluated.).

costs on consumers," Order 679 departed from prior Commission cost-benefit analysis requirements for incentives. [166] But a key justification for doing so was Order 679's nexus text, which "ensure[s] that incentives are granted only where the incentives are tailored to address the demonstrable risks or challenges faced by the applicant."[167] Given today's vastly different conditions, with no shortage of funds being invested in transmission (*see* response to Q 1), and where the Commission is considering abandoning its risks and challenges framework, costs must be brought back into the picture. As Order 1000 (PP 44-46) recognized, increasing transmission investment makes it all the more important that the more cost effective and efficient projects come to fruition. If the Commission adopts a benefits-based approach, it should restore Order 2000's requirement that applicants provide "a cost-benefit analysis, including rate impacts."[168]

Finally, because of the challenges of calculating benefits, the Commission should put clear, reasonable limits on total ROE incentives. *See* response to Q 97.

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?

If the Commission adopts benefits-based incentives, it should not grant ROE incentives unless: (1) the benefits and costs are calculated in accordance with the methodologies used in the applicable Order 1000 and Order 890 processes; and (2) the benefits, in relation to costs, are far in excess of those required to satisfy the criteria for selection for regional cost allocation. *See* response to Q 5 subpart g.

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[166] Order 679-A P 37.

[167] *Id*. P 40. Another cited factor—the role of non-cost considerations (*id*. P 39)—serves only to reaffirm the hazards of departing from the current risks and challenges approach.

[168] This requirement was codified in then 18 C.F.R. § 35.34(e)(ii) (2006), described in Order 679-A P 37 n.59.

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?

As discussed in response to Q 5 subpart b, if the Commission adopts a benefits-based approach to incentives, actual costs must be confirmed before the incentive is implemented and, if the duration of the incentive is not restricted to ten years or less, the Commission should make sure the claimed benefits are achieved, with consequences for failure to do so, including reduction, revocation, and potentially refund. As discussed in response to Q 86-89, such accountability requires periodic assessment, with an opportunity for evidentiary hearing to address material issues of fact and complexity of quantifying benefits, calculated on the basis used in applicant's incentive request or, if different, the basis on which the Commission granted the ROE incentive.

3. Incentives Based on Project Characteristics (Q 12-16)

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?

TAPS strongly opposes incentives based on project characteristics as a proxy for expected benefits. NOI P 18. Characteristics-based incentives suffer from all the infirmities of a benefits-based approach and more because benefits are simply assumed. The approach amounts to faith-based incentives, which is plainly inconsistent with the FPA. Assuming benefits, without the necessary inquiries,[169] does not eliminate the

[169] For example, granting incentives based on characteristics forecloses the close examination required to determine whether and the extent to which the project is an exemplary voluntary project, a required project, or gold-plating.

obligation to quantify consumer benefits from incentive rates, and to ensure that the incentive is worth the increased rates and no more than is needed to induce the benefits.[170] A characteristics-based approach also forecloses meaningful verification and measurement—no benefit and cost estimate would be available to compare to the final project costs before implementation, or to the benefits actually delivered.

A characteristics-based approach incorrectly assumes all projects that share a characteristic (e.g., "located in regions with persistent needs, interregional transmissions projects, or transmission projects that unlock constrained resources," (NOI P 18)) are equal. It also assumes they all have the benefits and the same costs relative to benefits, assumptions with no basis and which could lead to incentives for projects that deliver little or no net benefits. It is inconsistent with Section 219 to grant incentives based on unfounded assumptions, regardless of the project's costs, the relative cost of the generation constrained relative to what it would replace, potential lower cost transmission and non-transmission alternatives, and other factors relevant to assessing project benefits. While it is difficult to estimate benefits on an individual project basis, simply assuming the existence of benefits would result in unjust and unduly discriminatory rates.[171]

Characteristics-based incentives also share many of the other serious defects of a benefits-based incentives system, e.g., the creation of financial incentives inconsistent with RTO construction directives and Order 890 and 1000 planning processes (*see*

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[170] *See* response to Q 4 subpart a, citing 1992 Policy Statement and *City of Detroit*, 230 F.2d at 817.

[171] *Cf. Ill. Commerce Comm'n v. FERC,* 756 F.3d 556, 564-65 (7th Cir. 2014) (cost allocation remanded, finding "the basic fallacy of the Commission's analysis" was to assume uniform, grid wide benefits. "If the Commission after *careful* consideration concludes that the benefits can't be quantified, even roughly" it could estimate benefits, accounting for uncertainty; "future, speculative, and limited benefits" are insufficient to demonstrate benefits are roughly proportionate to costs).

response to Q 4 subparts b-c); fueling anti-siting sentiments; and alienating state siting authorities (*see* response to Q 4 subpart d).

In short, characteristics-based incentives are arbitrary and should be rejected.

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?

These questions highlight the shortcomings of a characteristics-based approach. The bright lines inherent in a characteristics-based approach are particularly problematic and arbitrary, inviting gold-plating and failing to ensure that Section 219's directives are satisfied. For example, when does a project qualify as new technology; and when is a technology no longer new?[172] Similarly, a project to access constrained generation may or may not make sense, depending on alternatives and expected changes in the grid and generation. Nor is transmission the right answer to persistent congestion in all cases; and adding incentives to the hefty costs of transmission may are make that solution less appropriate in a given circumstance.[173]

Question 14, regarding projects that satisfy multiply criteria, calls attention to the pitfalls of a characteristics-based approach. Putting multiple labels on a project does not mean that it is delivering significant benefits; and incentives should not be increased simply because an applicant can check off more than one characteristics box. As noted in response to Q 12, there is no basis to assume that two projects with the same characteristics will provide the same benefits at the same cost. And as described in response to Q 5 subpart a, it is not unusual for projects to provide multiple benefits; but

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[172] *See* response to Q 37-39.

[173] *See* response to Q 26-28.

scrutiny is required to ensure that mandatory projects are not improperly awarded incentives for their other attributes—simply summing benefits would be incorrect.

If the Commission adopts characteristics-based incentives, the principles identified in response to Q 5 (e.g., planning process prerequisites, joint ownership) should be applied on a case-by-case basis to mitigate the serious deficiencies of this approach.

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's risks and challenges framework, as implemented through the 2012 Policy Statement, provides a reasonable degree of certainty as to the availability of risk-reducing incentives and the tests it must satisfy to secure ROE incentives. Any potential increase in certainty from adoption of a characteristics-based approach comes at the cost of violating Section 219, and burdening consumers and businesses with unnecessary and unjustified costs that impede getting transmission built.

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

Absolutely not. *See* responses to Q 7, 13-14.

B. Incentive Objectives

1. Reliability Benefits (Q 17-21)

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?

The NOI (P 22) rightly acknowledges that TOs are already required to address reliability through compliance with NERC reliability standards and other planning criteria. Consistent with the Commission's "longstanding policy that incentives should only be awarded to induce voluntary conduct,"[174] incentives are not needed for transmission investments made in compliance with mandatory standards.

Benefits-based incentives for projects that enhance reliability above and beyond what is required by mandatory standards are inappropriate: (1) the Commission's cost recovery policies already make such projects attractive, low-risk investments; and (2) adding further incentives would invite gold-plating.

First, as Chairman Chatterjee noted at the March 2019 technical conference on security investments, the Commission "has been very accommodating in providing a number of mechanisms for utilities to recover the costs of their prudently incurred security expenditures."[175] Widespread adoption of formula rates combined with the Commission's "presum[ption] that all expenditures are prudent"[176] significantly reduces the risk that TOs will not recover costs related to improving reliability and security beyond what is required by mandatory standards. Commissioner Glick's conclusion at the end of that 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."[177]

Investors have confirmed that investing in grid reliability is a good deal. Nick Atkins, CEO of AEP, stated that investments in resiliency and reliability of the grid are

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[174] NOI P 48 (citing *CPUC 2018*, 879 F.3d at 978). *See* response to Q 5 subpart a.

[175] Transcript from March 28, 2019 Technical Conference at 151:5-7, *Security Investments for Energy Infrastructure Tech. Conferences*, Docket No. AD19-12-000 (Apr. 26, 2019), eLibrary No. 20190426-4001 ("Security Conference Transcript").

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

[177] Security Conference Transcript at 187:22-24; *see also id.* at 78:17 (regulators typically allow recovery of costs associated with resiliency and reliability of the grid); *id.* at 151:14-16 (Exelon's six utilities "have not experienced any issues with recovery on the prudent investments around the physical and cybersecurity.").

"really probably one of [the] least risky investments we can make."[178] EEI estimates that electric utilities have invested $285 billion in transmission and distribution since 2012 to harden the grid and make it more resilient.[179] That trend will continue, with EEI estimating that "about a quarter of electric company transmission spending through at least 2021 is expected to be devoted to improving resilience and security, as well as to integrating advanced technologies."[180]

Second, benefits-based incentives for improving reliability would invite TOs to gold-plate their systems, potentially in discriminatory ways. This is especially true for reliability projects not selected through an open and transparent transmission planning process. Order 890 found that TOs could not be relied on to expand the grid in a not unduly discriminatory manner, and implemented transmission planning requirements.[181] Order 1000 relied on evidence of unduly discriminatory and preferential practices in the transmission planning process to adopt additional reforms.[182] Yet TOs continue to make massive investments—in some cases more than half of their transmission investment—in "asset management" projects that are not subject to any stakeholder-involved transmission planning process and are approved only by utility executives.[183] Much of that self-approved transmission investment is for reliability projects.[184] Particularly

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[178] Security Conference Transcript at 78:18-19.

[179] EEI White Paper at 3.

[180] *Id.* at 5. *See also* response to Q 1.

[181] Order No. 890 at PP 421-25, 435-37; *Pro Forma* OATT, Attachment K.

[182] Order 1000 PP 58-59.

[183] *See Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, P 48, 11 (2018) (allowing 60% of Pacific Gas & Electric Company's capital transmission spending authorized through a self-approval process involving only its Chief Financial Officer and Project Managers).

[184] *See id.* P 12.

given the limited scrutiny of the need for and cost-effectiveness of such projects, the Commission should not add further incentives (beyond the potent inducements in its cost recovery policies) to the opportunity for gold-plating.[185]

There is no indication that TOs are failing to make adequate reliability investments. To the contrary, TOs have been investing and will continue to invest heavily to improve reliability—above and beyond what NERC standards require. Benefits-based incentives will result in unjust and unreasonable rates.

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?

If the Commission allows benefits-based incentives for reliability, it should set the bar extremely (if not insurmountably) high for projects not fully vetted through an Order 1000 or Order 890 planning process that has a robust benefits evaluation methodology and considers alternatives, as discussed in response to Q 5 subpart g. The Commission should apply all the principles described in Q 5; but to illustrate the challenges, we focus here on the need for benefits to be clearly defined and quantified relative to costs, and periodically reassessed if the duration of the incentive extends beyond ten years.[186]

Specifically, an applicant seeking incentives for a reliability benefit must clearly demonstrate how the project goes above-and-beyond mandatory requirements and identify and quantify those benefits, demonstrating that they substantially exceed the costs and are not gold-plating. "Vague statements such as 'increased system reliability'

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[185] *See* response to Q 1 (describing utility communications with investors about the impact of their increasing transmission investments).

[186] *See* response to Q 5 subparts a-c, e.

are not acceptable."[187] Measuring the above-and-beyond reliability benefits will be very difficult, complicated by the need to determine which portions of a project are necessary to meet a mandatory standard (and merit no incentive) and which go above and beyond, and then measuring and quantifying the incremental benefits associated with the above-and-beyond expenditures relative to their costs. Because evaluation of expected benefits will depend heavily on the specifics of a given project, the Commission cannot reasonably adopt any bright-line tests or rebuttable presumptions, much less a characteristics-based approach. Material factual and modeling issues inherent in evaluating and quantifying benefits may well necessitate evidentiary hearings.

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?

TAPS does not support benefits-based incentives for transmission that expands access to essential reliability services. The Commission has taken several actions to address the reduction in capacity that provides essential reliability services.[188] These include approval of NERC Reliability Standard BAL-003-1, which establishes frequency response obligations for Balancing Authorities ("BA"), allowing each BA to assess the amount of primary frequency response available to it, and develop appropriate solutions to ensure the BA (or Frequency Response Sharing Group) has enough frequency response to maintain system reliability on the interconnection.[189] More recently, the Commission

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[187] 1992 Policy Statement at 61,601.

[188] *See, e.g., Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014) ("Order 794"); *N. Am. Elec. Reliability Corp.*, 146 FERC ¶ 61,025 (2014) (ERCOT Primary Frequency Response); *Third-Party Provision of Primary Frequency Response Service*, Order No. 819, 153 FERC ¶ 61,220 (2015).

[189] Order 794 PP 14-15.

required newly interconnecting large and small generating facilities (synchronous and non-synchronous) to install, maintain, and operate equipment capable of providing primary frequency response.[190]

As these actions highlight, essential reliability services are provided by generators. There is no evidence that expanding transmission is an effective, let alone least-cost, method of increasing access to essential reliability services. To the extent transmission expansion could cost-effectively contribute to essential reliability services, those contributions should be considered through the Order 890 or Order 1000 transmission planning process, the same way other reliability criteria are considered. Incentives for such projects are not needed.[191] But if the Commission were to consider them, it would face particularly difficult measurement and quantification challenges.[192]

2. Economic Efficiency Benefits (Q 22-25)

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?

TAPS supports application of the risks and challenges framework, rather than benefits-based incentives, for projects that reduce congestion or facilitate access to additional generation. Even if a particular project would provide those benefits, an

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[190] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128 (2018).

[191] *See* response to Q 17-18.

[192] *See* response to Q 19.

incentive that needlessly inflates consumer costs—i.e., because that rate incentive was not necessary to induce investment in the project—would conflict with Section 219. If the Commission adopts benefits-based incentives, it should do so in a manner that reinforces rather than undermines its Order 890 and Order 1000 planning processes, and rewards only exemplary projects. *See* response to Q 5 subpart g.

The Commission has already developed significant non-rate mechanisms to foster transmission projects that reduce congestion or facilitate access to additional generation. Order 890 required all TPs to satisfy the "Economic Planning Studies" planning principle, by providing study procedures for economic upgrades to address congestion or the integration of new resources on an aggregated or regional basis.[193] The same two goals are incorporated in Order 890's regional participation principle (P 523). Order 1000 likewise required regional plans that expressly address economic considerations and meet transmission needs driven by public policy requirements.[194]

As discussed in the response to Q 5 subpart g, to avoid undermining these processes: (1) the Commission should not award benefits-based rate incentives to transmission projects that have not been evaluated and selected through the applicable Order 1000 and Order 890 planning processes; and (2) any benefits-based incentives system should be closely integrated with Commission-approved project benefits-

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[193] *See* Order 890 PP 547-49. As discussed in response to Q 5 subpart a, transmission projects to interconnect *specific* generators and enable their OATT delivery to load should not be eligible for incentives. They are mandatory projects that the *Pro Forma* OATT requires TOs to build, subject to "or" pricing (for transmission service, *see* Order 888 at 31,741; Order 890 P 1028) and upfront funding (for interconnection service, *see Pro Forma* LGIA Articles 11.3, 11.4.1).

[194] *See, e.g.*, Order 1000 P 47; *Tampa Elec. Co.*, 143 FERC ¶ 61,254, P 56 (2013) ("Order No. 1000's affirmative obligation to identify more efficient or cost-effective transmission solutions applies to transmission needs driven by economic considerations just as it applies to transmission needs driven by public policy requirements or reliability considerations.").

evaluation methodologies used in those processes. Significant variation in existing benefits-evaluation methodologies will make bright-line metrics for benefits-based incentives unworkable. The Commission should grant benefits-based ROE incentives only if the benefits (in relation to costs) are extraordinary—far in excess of the at most 1.25:1 benefit-cost ratio cut-off for projects considered for selection for regional cost allocation. But because different TPs use different benefits-evaluation methodologies,[195] no bright-line benefit-cost ratio would work across all regions and transmission systems.

3. Persistent Geographic Needs (Q 26-28)

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 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?

The NOI's persistent geographic needs objective is a more long-lasting and severe variant on economic efficiency projects, and thus the response to Q 22-25 is applicable. If chronic congestion and conditions requiring operating procedures have not been relieved through prudent planning as supplemented by the planning processes required by Order 890 and 1000, the issue is unlikely to be relieved by ROE incentives—e.g., raising the price tag may exacerbate siting challenges. The Commission's efforts would be better spent understanding those obstacles, and if appropriate supplementing the Order 890 and Order 1000 planning processes to better address them, rather than throwing ratepayer money at it.

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[195] *See* response to Q 5 subpart g.

For example, one of the 13 areas identified in the 2017 Transmission Metrics Report as having persistent price separation and high prices includes the Upper Peninsula of Michigan ("UP"), where the separation has persisted for 11 years.[196] Because of the limited UP load and the high cost of transmission solutions, it was more cost effective to add new generation rather than transmission. The Michigan Public Service Commission approved construction of two natural gas-fueled power plants after finding that they would cost less than the estimated $373 million required to upgrade and build new transmission facilities.[197] MISO's transmission expansion study, conducted at the request of Michigan's Governor, concluded that none of the transmission expansion options produced benefits exceeding construction costs.[198]

This Commission's Staff has cautioned against assuming that additional transmission investment is needed or appropriate to address persistent price separation:[199]

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[196] 2017 Transmission Metrics Report at 36-42 (including figs. 8-11).

[197] *In re Upper Mich. Energy Res. Corp.*, Case No. U-18224 at 40, 62, 99 (Mich. Pub. Serv. Comm'n. Oct. 25, 2017), https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UW1yAAG ("The Staff explained that transmission options have been thoroughly evaluated by [Upper Michigan Energy Resources Corporation] and MISO over the past several years . . . . According to the Staff, the two-site design of the [generation] project was specifically planned to alleviate the immediate need for significant investment in new and upgraded transmission lines that would have an estimated capital cost of $373 million." "[T]he UP is a load pocket that has very specific needs . . . ").

[198] Nick Assendelft, *Costs Exceed Benefits of Electrical Connections at Soo and Straits Results of Study Indicate Area Where UP Could Add Further Generation to Aid Reliability with Minimal Infrastructure Costs*, Mich. Dep't of Licensing and Regulatory Affairs (Oct. 27, 2017), https://www.michigan.gov/lara/0,4601,7-154--450941--,00.html; Amanda Durish Cook, *MISO: Tx Link from Ontario to Mich. UP Not Cost Effective*, RTO Insider (Nov. 2, 2017), https://www.rtoinsider.com/miso-michigan-ontario-transmission-study-79011/.

[199] 2017 Transmission Metrics Report at 34. Staff explained (at 42): "First, there may be reasons other than insufficient transmission capacity why high or low prices persistently occur in a particular case. For example, a state may have a renewable portfolio standard that only counts in-state resources toward compliance, thus requiring the use of potentially more expensive local resources no matter how much transmission capacity may be available to access lower cost resources elsewhere. Second, even if more transmission capacity could reduce the deviation of price from the market average in a particular case, if the cost of the needed transmission upgrade would exceed this benefit, it might not be beneficial to undertake such an upgrade. Finally, lines connecting points where high prices occurred to points where low prices occurred might not help equilibrate prices as much as might be expected based only on this

> Price differentials between areas within an RTO/ISO may be the result of inadequate transmission capacity, capacity that is necessary to deliver power from areas with lower prices to those with higher prices. However, not all price differentials can be addressed economically; in some cases, the costs associated with the transmission infrastructure necessary to reduce a price differential may exceed the benefits that alleviating that congestion could provide. In such cases, persistent price differentials do not necessarily indicate insufficient transmission investment.

Rather than assuming transmission is the best cure for all persistent congestion, and further assuming that incentives will be helpful (as opposed to counterproductive) to curing that perceived disease, the Commission should focus on understanding why the constraints have not been relieved by transmission and then, if appropriate, require adjustments to the planning process to address any deficiencies identified. As a first step, the Commission could require RTOs to report on whether the persistent price separation areas identified in the 2017 Transmission Metrics Report have been addressed (or otherwise been relieved) and if not, why not. If appropriate the Commission could convene one or more technical conferences to explore the issue in particular regions.

Further, the Commission needs to consider whether granting incentives for relieving persistent congestion discourages TOs from timely addressing constraints. In the highly unlikely case that lack of ROE incentives is the obstacle to relieving chronic congestion or limitations requiring operating procedures, the prudence of the TO's failure to take action earlier warrants consideration. Downward adjustments in ROE may be appropriate for TOs that could have relieved the persistent congestion but failed to do so.

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analysis. For example, the high prices and the low prices may not occur at the same time of the year."

As discussed in response to Q 5 subpart f, particularly if the Commission moves away from Order 679's risks and challenges framework, symmetry is required.

4. Flexible Transmission System Operation (Q 29-31)

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?

TAPS urges the Commission not to grant incentives for claimed flexibility for the reasons discussed in response to Q 17-18. Flexibility is particularly hard to define or quantify, much less to measure and verify that the promised consumer benefits materialize and continue to provide value over the duration of the incentives.[200] Flexibility is also difficult to distinguish from and may overlap with other possible incentives objectives identified in the NOI (e.g., resilience, economic projects, enhanced reliability). And it will be difficult to distinguish from gold-plating.

Given the amorphous nature of this attribute, and its potential to change over time, and with changes in the grid and the generation mix, the Commission should be particularly reluctant to grant flexibility incentives, especially outside Order 1000 and robust Order 890 planning processes where the project's claimed value can be fully vetted, assessed in relation to its costs, and compared with other alternatives.

5. Security (Q 32-33)

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?

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[200] Absent limitation of incentives to no more than ten years, the benefits actually delivered must be periodically reassessed, with the incentive reduced or eliminated if the estimated benefits on which the incentives were awarded do not materialize or are not sustained. *See* responses to Q 5 subpart e and Q 86-89.

For the reasons discussed in response to Q 17-18, TAPS does not support benefits-based incentives to enhance physical and cyber security at transmission facilities. The Commission should not provide incentives for such investments to comply with mandatory standards. NERC's Critical Infrastructure Protection standards already require TOs to take significant measures to protect the security of the grid, and TOs are entitled to recovery of prudently incurred costs to satisfy those requirements.[201]

Nor should the Commission provide incentives for security investments that go above and beyond mandatory standards. As discussed in response to Q 17-18, incentives for above-and-beyond measures are unnecessary, because the Commission's strong cost recovery mechanisms make physical and cyber-security projects a low risk investment.[202] TOs are already making substantial security investments.[203] If the Commission offers such incentives, it should apply the principles discussed in response to Q 5 and 19.

6. Resilience (Q 34-36)

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

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

TAPS supports the Commission's ongoing efforts to more rigorously define resilience and to consider the appropriate role for RTOs with respect to evaluating and

[201] Additionally, FPA Section 215A(b)(6), 16 U.S.C. § 824o-1(b)(6), provides a mechanism for entities to recover costs incurred to comply with an order for emergency measures issued pursuant to that section, to the extent such costs were prudently incurred and cannot be reasonably recovered through regulated rates.

[202] *See* Security Conference Transcript at 187:22-24; *see also id.* at 78:17 (regulators typically allow recovery of costs associated with resiliency and reliability of the grid); *id.* at 151:14-16 (Exelon's six utilities "have not experienced any issues with recovery on the prudent investments around the physical and cybersecurity.").

[203] EEI White Paper at 3, 5 (describing past and future investments in security).

achieving appropriate levels of resilience.[204] However, as the NOI recognizes (P 28), resilience is not one of the objectives enumerated in Section 219, and thus the Commission cannot grant incentives for enhancing resilience except to the extent that such projects "promote reliable . . . transmission and generation of electricity."[205]

Although there is some overlap with reliability, the "concept of resilience necessarily involves issues, topics, and questions that extend beyond the Commission's jurisdiction, such as distribution system reliability and modernization."[206] The Commission's jurisdiction under Section 215 is limited to the bulk power system ("BPS"), which expressly excludes distribution facilities.[207] The Commission cannot give incentives for projects that improve resilience of distribution facilities, which are subject to the jurisdiction of state and local regulators.[208] Even for BPS facilities, the FPA focuses on reliable operations to protect against "instability, uncontrolled separation, or cascading failures" that result from a "sudden disturbance . . . or unanticipated failure of system elements."[209] The proposed definition of resilience[210] is broader than that.[211]

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[204] *See* TAPS Comments, *Grid Resilience in Reg'l Transmission Orgs. & Indep. Sys. Operators*, Docket No. AD18-7-000 (May 9, 2018), eLibrary No. 20180509-5081 ("TAPS Resilience Comments").

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

[206] *Grid Reliability and Resilience Pricing and Grid Resilience in Reg'l Transmission Orgs. & Indep. Sys. Operators*, 162 FERC ¶ 61,012, P 19 n.31 (2018).

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

[208] State and local regulators are already actively addressing distribution system resilience issues. *See* response to Q 36.

[209] Section 215(a)(4).

[210] NOI P 28 ("the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.") (citation omitted).

[211] The statute describes the objective of reliability standards as "provid[ing] for an adequate level of reliability of the bulk power system." Section 215(c)(1). NERC's definition of Adequate Level of Reliability, which focuses on addressing routine, predetermined disturbances, is instructive in its effort to

Even if a resilience-enhancing transmission project can be shown to improve BPS reliability, that does not mean incentives would be appropriate. Incentives are not warranted for projects needed to comply with mandatory standards. To the extent a resilience-enhancing project can be viewed as enhancing reliability above and beyond mandatory requirements, Section 219 incentives are unnecessary.[212] Allowing incentives for such projects' reliability benefits would invite gold-plating and produce unjust and unreasonable rates. If the Commission offers incentives for them, Section 219 requires that it consider only reliability (not resilience) benefits. In doing so, the Commission should apply the principles discussed in response to Q 5 and 19.

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?

Because resilience extends beyond its authority, the best way for the Commission to incentivize resilience-enhancing projects may be to partner with state and local regulatory authorities who better understand the resilience challenges faced by their utilities.[213] State and local regulators are already actively addressing distribution system resilience. For example, Florida's legislature passed a bill this year that creates a special cost recovery mechanism for investor-owned utilities' storm hardening efforts.[214] And distribution utilities, along with state and local regulators, have developed tools and relationships to support distribution system resilience, including standing mutual aid

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provide criteria by which reliability can be measured and distinguished from gold-plating. NERC, Informational Filing on the Definition of "Adequate Level of Reliability", *N. Am. Elec. Reliability Council & N. Am. Elec. Reliability Corp.*, Docket No. RR06-1-000 (May 10, 2013), eLibrary No. 20130510-5126.

[212] *See* responses to Q 5 subpart a and Q 17-18; NOI PP 22, 48.

[213] Threats to resilience vary by location. In California, wildfires and earthquakes pose significant threats, while in New England, challenges arise from heavy reliance on gas-fired generation dependent on just-in-time fuel delivery. *See* TAPS Resilience Comments.

[214] S.B. 796, 2019 Sess. (Fla. 2019) (awaiting governor's signature).

agreements, and designated utility, network, and national coordinators to ensure coordinated response among utilities and with state and federal governmental officials.[215]

The Commission's many tools—outside of its Section 219 authority—to support and supplement state and local regulators efforts to promote resilience are the subject of Docket No. AD18-7-000, which may result in actions that reduce or eliminate any claimed need for resilience incentives. If it offers such incentives, risk-reducing incentives would be more appropriate than ROE incentives. *See* responses to Q 1 and 2.

7. Improving Existing Transmission Facilities (Q 37-43)

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?

TAPS supports improving the capacity and efficiency of existing facilities as a means to avoid unnecessary transmission additions. And we recognize that Section 219(b)(3) provides for incentives for deployment of transmission technologies and other measures that would achieve that goal. However, we are skeptical of the use of benefits-based incentives to spur such investment, divorced from the 2012 Policy Statement's framework which recognizes that a particular deployment of new technology may merit an incentive ROE because of the risks and challenges it poses. As the NOI's questions highlight, a benefits-based incentives approach to deployment of new transmission

[215] *See, e.g.*, EEI *Understanding the Electric Power Industry's Response and Restoration Process* (2016), http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/MA_101FINAL.pdf; American Public Power Association, *Mutual Aid* (2018), https://www.publicpower.org/mutual-aid.

technologies will be extremely difficult to implement. Thus, TAPS urges against departing from the current approach.

If the Commission decides to do so, safeguards are needed. First, technology investments not considered in an Order 1000 or Order 890 planning process should be ineligible for incentives. Section 219(b)(3) allows incentives for technologies or other measures only if they "increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities." An investment that increases transmission capacity "would be subject to the transmission planning requirements of Order No. 890."[216] Routine maintenance, repair, or replacement of transmission facilities would not be subject to an Order 1000 or Order 890 process, but it would also fail Section 219(b)(3)'s criterion of increasing the capacity of existing transmission facilities.

Consideration of a project in an Order 890 or Order 1000 process would not, by itself, justify awarding a technology-based incentive;[217] and distinguishing between advanced technologies potentially meriting an incentive versus improvements that should be made in the ordinary course will be challenging. Novel technologies will become the norm if they deliver; and keeping up with good utility practice as it evolves is the TO's baseline obligation—not a justification for increased ROEs.[218] The rapid pace of technological change means that any criteria will be subject to continuous change,

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[216] *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, P 69 (2018).

[217] As compared with projects selected through an Order 1000 process, greater scrutiny will be necessary for a project approved through an Order 890 transmission planning process that does not quantify benefits using a consistent, Commission-approved methodology, rigorously compare proposed projects to transmission and non-transmission alternatives, and share information sufficient to enable stakeholders to replicate the TP's decisions. *See* response to Q 5 subpart g.

[218] *See United Illuminating Co.*, 167 FERC 61,126, PP 62-63 (2019) (denying ROE incentive for project that used technology that had not been shown to be novel or innovative). *See also* responses to Q 5 subpart a and Q 17-19. EEI's White Paper provides several examples of its members' actions to expand the capacity of existing facilities, apparently without ROE incentives by the Commission.

making non-discriminatory application challenging. Should the first, fifth, and tenth TO seeking incentives for applying similar technologies receive the same incentive? And how can the Commission avoid incenting untested technologies?

Once a potentially deserving transmission technology is identified, measuring the incremental benefits (relative to incremental costs) will be difficult. Thus, benefits-based incentives for improving existing facilities will be hard to administer.[219]

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?

If by "stand-alone, transmission technology-related incentive," the NOI (P 29) is inquiring about technologies other than "transmission technologies . . . [that] increase . . . capacity and efficiency . . . and improve operations," such incentive would exceed Section 219(b)(3) and should not be provided. If the NOI is referring to an incentive that is made available outside the risks and challenges framework applied to technology by the 2012 Policy Statement, the answer is also no. The 2012 Policy Statement rightly subjected technology incentives to the risks and challenges framework, while recognizing such projects may merit an incentive ROE because the risks and challenges may not be either accounted for in the applicant's base ROE or addressed by a risk reducing incentives.[220] That approach should be continued. *See* response to Q 37-39.

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[219] A further wrinkle, highlighted by the NOI's reference (P 29) to storage as a technology under consideration, is the challenge posed by facilities with multiple revenue streams, including cost-of-service recovery for certain transmission-related services. While the Policy Statement, *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 PP 15-19 (2017) provides guidance on the need to avoid double recovery and methods to do so, incentives will complicate this process and enhance the likelihood of unintended consequences.

[220] 2012 Policy Statement PP 21, 23.

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?

TAPS does not support an incentive that would allow public utilities to include any O&M expenses in rate base. First, the Commission's Uniform System of Accounts has well-established rules for determining what costs must be expensed and what costs must be capitalized, as well as clear rules regarding creation of regulatory assets. There is no reason to upend existing practice, especially for utilities with formula rates that all but guarantee their O&M expenses will be promptly recovered.

Second, including technology-related O&M expenses in rate base will not necessarily encourage their deployment. Assuming that a utility's authorized rate of return is equal to its cost of capital, it should be indifferent to recovering the cost of grid management technology as an O&M expense or through a regulatory asset.[221] Although the utility would nominally earn more money through the return on a regulatory asset, the utility would also incur the carrying costs of money that would have otherwise been recovered within the operating year. Those extra returns should be equal to the extra costs. Allowing utilities to include technology expenses in rate base will not incentivize utilities to deploy such technology, and may actually discourage such deployment.[222]

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[221] If the utility's allowed rate of return is higher than its cost of capital, the utility would be induced to inefficiently increase capital assets. *See* H. Averch & L.L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 Am. Ec. Rev. 1052 (1962).

[222] Including expenses in rate base will tie up available capital that could have been deployed elsewhere, which could have an adverse impact on rating agencies' evaluation of the utility's risk. And delaying recovery of transmission-related expenses increases risk and reduce cash flow, which may discourage deployment. *Cf.* 2012 Policy Statement P 12 (earlier cost recovery provides "up-front regulatory certainty, rate stability and improved cash flow, which in turn can result in higher credit ratings and lower capital costs.").

Third, including O&M expenses in rate base violates the basic accounting principle of matching revenues to expenses and the equivalent regulatory principle of matching costs and benefits. Treating O&M expenses as capital expenditures would result in future ratepayers paying for services received by current ratepayers. There is no reason to allow an incentive that would create such intergenerational inequity.

Finally, allowing utilities to include some technology-related O&M expenses in rate base may prove impractical and involve difficult line-drawing questions: Which technologies? How would the Commission distinguish established technologies that are used as good utility practice from new technologies that would not be used without an incentive? And how quickly will a 'new' technology become 'established'?[223]

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?

The Commission should not grant RTOs incentives for adopting better technologies for grid management, transmission asset efficiency, market performance, or other purposes. RTOs are not-for-profit entities.[224] Rate incentives will be ineffective, as any above-cost returns awarded to RTOs must be returned to load—the same entities that paid for the incentives.

They are also unnecessary. RTOs' core missions are to "improve efficiencies in the management of the transmission grid,"[225] including "regional transmission pricing, improved congestion management of the grid, more accurate ATC calculations, more

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[223] *See* response to Q 37-39.

[224] As entities formed under section 501(c) of the Internal Revenue Service Code, there are considerable restrictions on the inurement or private benefit these entities may retain. *See, e.g.*, 26 U.S.C. § 501(c).

[225] Order 2000 at 31,017.

effective management of parallel path flows, reduced transaction costs, and facilitation of state retail access programs";[226] "improve grid reliability"; "remove opportunities for discriminatory transmission practices"; and "improve[] market performance."[227] *See* RTO mission statements.[228] Stakeholder processes are used to hold RTOs' feet to the fire on delivering grid management efficiencies, resulting in significant annual savings and added value to the regions these entities serve.[229] Various RTOs have employee bonus plans and executive compensation for performance tied to operational goals.[230]

There is no evidence that RTOs are failing to keep pace with technology to enhance multiple market administration and market purposes.[231] Nor is there any reason to press beyond the limits of Section 219, which does not authorize incentives for "improved market performance." To the extent that the Commission is concerned that RTOs are not keeping pace with technology, those concerns should be addressed through

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[226] *Id.* at 31,017 n.99.

[227] *Id.* at 31,017.

[228] *E.g.*, MISO, *About MISO*, https://www.misoenergy.org/about/ (last visited June 24, 2019) (MISO's "cornerstones of customer service, effective communication and operational excellence anchor [its] mission to work collaboratively and transparently with . . . stakeholders to enable reliable delivery of low-cost energy through efficient, innovative operations and planning."); PJM, *PJM's Mission & Vision*, https://www.pjm.com/about-pjm/who-we-are/mission-vision.aspx (last visited June 24, 2019) (PJM's mission includes "ensur[ing] the safety, reliability and security of the bulk electric power system" and "[understanding] customer needs and deliver[ing] valued service to meet those needs in a cost-efficient manner.").

[229] *See* MISO, *MISO Releases 2018 Value Proportion Study Results* (Feb. 19, 2019), *https://www.misoenergy.org/about/media-center/miso-releases-2018-value-proposition-study-results/* ("MISO's latest Value Proposition study continues to document the substantial annual savings we are able to generate for the region we serve").

[230] *See, e.g.*, *ISO New England Inc.*, 129 FERC ¶ 61,299, P 27 (2009) ("ISO-NE explains that it has a 'pay for performance' compensation program that is based on objective and measurable goals set by the board that reflects organizational goals for operational reliability, efficient and competitive markets, budget performance, and service excellence in stakeholder processes.") (citation omitted).

[231] *E.g.*, MISO's major, multi-year market enhancements are now underway. MISO, Technology Committee of the Board of Directors, *Market System Enhancement Program* (Mar. 19, 2019), https://cdn.misoenergy.org/20190319%20Technology%20Committee%20of%20the%20BOD%20Item%2004%20Market%20System%20Enhancement327152.pdf.

the Commission's annual technology technical conferences, which offer a targeted forum "to explore research and operational advances with respect to market modeling that appear to have significant promise for potential efficiency improvements." [232]

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.

The Commission should restrict Section 219(b)(3) incentives to "transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities." Stretching Section 219(b)(3) incentives to include measures that "achieve the same goals as new transmission" (as the question inquires, NOI P 29) would have no effective boundaries.[233] For example, Order 1000 rightly required consideration of non-transmission alternatives in the transmission planning process, but that does not mean that a non-transmission (including generation or other technology) solution, which substitutes for transmission, qualifies for Section 219 incentives.

Order 679 (PP 271-72) found adoption of performance-based rates premature, given an industry structure—with great diversity as to those who own and operate transmission, and regional and density differences—that made determination of generally applicable performance benchmarks unworkable. That diversity has not changed.

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[232] *See, e.g.*, Notice of Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency and Enhancing Resilience Through Improved Software at 1, *Increasing Mkt. & Planning Efficiency Resilience Through Improved Software*, Docket No. AD10-12-010 (Mar. 29, 2019), eLibrary No. 20190329-3062.

[233] *See* response to Q 37-39.

8. Interregional Transmission Projects (Q 44-46)

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?
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?

Granting benefits-based incentives to interregional projects, especially ROE adders, will make it *less* likely that such projects will get built. The challenge under existing interregional coordination processes has not been a lack of investors, but rather the inability to successfully obtain necessary approvals. Incentives that increase project costs will make getting such approvals even harder.

The Pioneer Project—a MISO-PJM interregional project proposed by Pioneer Transmission, LLC ("Pioneer"), a joint venture of AEP and Duke Energy Transmission Holding Co.—is instructive. Pioneer sought and received a 150 basis point ROE incentive for new transmission for its proposed Pioneer Project.[234] MISO approved its component of the Project, the Greentown-Reynolds Line, but slightly modified Pioneer's proposed route in a manner that allowed Northern Indiana Public Service Co. ("NIPSCO") to claim the right to invest and partially own the facility.[235] Pioneer sued NIPSCO, asserting that NIPSCO had no right to invest, and that full ownership of the Greentown-Reynolds Line should be awarded to Pioneer. The Commission denied Pioneer's complaint.[236]

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[234] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009), *clarified and reh'g denied*, 130 FERC ¶ 61,044 (2010).

[235] *Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, P 9 (2018).

[236] *Pioneer Transmission, LLC v. N. Ind. Pub. Serv. Co.*, 140 FERC ¶ 61,057 (2012).

Construction of the Greentown-Reynolds Line proceeded with Pioneer and NIPSCO sharing ownership. Although NIPSCO applied for and received risk-reducing incentives for its ownership share,[237] it did not seek the 150 basis point adder that Pioneer had originally been granted for the Pioneer Project. Meanwhile, Pioneer sought a waiver of the conditions of its original 150 basis point adder for the Pioneer Project so that it could receive that ROE adder on its share of the Greentown-Reynolds Line without having received PJM approval for the PJM portion of the interregional project.[238] The Commission denied that request without prejudice to Pioneer seeking to implement the full ROE adder if it satisfies the Commission's previously stated conditions.[239]

The Pioneer Project illustrates the ability to attract investors in major transmission projects *without* ROE adders, and the rent-seeking behavior that ROE adders can encourage, with their potential to needlessly drive up costs. While Pioneer claimed it needed a substantial ROE adder to justify its investment in the Greentown-Reynolds Line, NIPSCO was not only willing to invest in the Line without that ROE incentive, it was willing to litigate to protect its right to do so. Pioneer apparently thought the ROE adder was so valuable that it sued to exclude NIPSCO from joint ownership, so that Pioneer could receive a 150 basis point adder on the full investment.

Meanwhile, PJM has not approved the PJM component of the Pioneer Project, presumably because it determined that other upgrades would be more cost-effective and efficient. This obstacle—not inadequate incentives—is why the full Pioneer interregional

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[237] *N. Ind. Pub. Serv. Co.*, 141 FERC ¶ 61,231 (2012) (approving inclusion of 100 percent of prudently-incurred CWIP in rate base and abandoned plant incentive).

[238] MISO, Pioneer Attachment O Filing, Transmittal Letter at 16, *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER18-1159-000 (Mar. 22, 2018), eLibrary No. 20180322-5246.

[239] *Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, PP 1, 22.

project has not been constructed. And awarding greater rate incentives—with their corresponding increases in costs—will make it more difficult for such projects to demonstrate the benefit-cost ratios needed to obtain necessary regional approvals.

If the Commission is serious about encouraging interregional projects, it should take a hard look at the Order 1000 interregional coordination process. That interregional projects have been "scarce" (NOI P 30) does not necessarily mean that interregional processes have failed,[240] but that process may need to be revisited. "Interregional Transmission Coordination Issues" was a major topic at the 2016 Competitive Transmission Development Technical Conference,[241] but at that time many regions had not completed even one interregional coordination cycle. Three years later, it's time to assess whether strengthening or streamlining is appropriate.[242]

9. Unlocking Locationally Constrained Resources (Q 47-49)

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?

As explained in response to Q 5 subpart a and Q 22-25, projects designed to interconnect specific generators and enable their delivery to load should not be eligible for incentives, as TPs are required to build these facilities under Orders 888 and 2003.[243]

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[240] For example, if adjacent regions are resource-adequate, trade along their border is likely to be marginal, and proper application of appropriate selection and approval criteria may well result in relatively few interregional project approvals.

[241] Supplemental Notice of Technical Conference and Request for Speakers at 6 ("Panel 4: Interregional Transmission Coordination Issues"), *Competitive Transmission Dev. Tech. Conference*, Docket No. AD16-18-000 (May 10, 2016), eLibrary No. 2016-510-3055.

[242] *See* response to Q 5 subpart g (discussing recent MISO-SPP interregional planning filing).

[243] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC

The key way to promote appropriate projects to connect new areas of developing generation is through Order 890 and Order 1000 planning processes. Those processes expressly require TOs to consider potential upgrades or other investments to integrate new resources on an aggregated or regional basis outside of a specific interconnection or transmission service request. Open, transparent, collaborative, and non-discriminatory planning processes—which can evaluate multiple alternate future scenarios and develop a plan that would be robust under most, if not all, futures—is far superior to attempting to address such needs through *ad hoc* analyses based on tabulating the number and size projects in interconnection queues, many of which are unlikely to ever be built.[244]

If the Order 890/1000 processes are not producing sufficient projects of this nature, they need to be improved. Queue reform may be part of the solution both by smoothing out the uneven, "straw that broke the camel's back" pattern of network upgrade cost assignment, and reducing "dead wood" in the interconnection queue. In contrast, creating a separate, inconsistent system for incenting such projects will confuse

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¶ 61,103 (2003) ("Order 2003"), *clarified*, 106 FERC ¶ 61,009, *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. NARUC v. FERC, 475 F.3d 1277* (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

[244] *See, e.g.*, *Interconnection Queuing Practices*, 122 FERC ¶ 61,252, P 15 (2008) ("[T]he relatively small deposit amounts, coupled with the incentives produced by a first-come, first-served approach to allocating capacity, provides an incentive for developers to secure a place in the queue even for projects that may not be commercially viable."); Public Service Company of Colorado, Tariff Revisions to Modify Suspension Language in the Large Generator Interconnection Agreement at 2-3, *Pub. Serv. Co. of Colo.*, Docket No. ER18-1201-000 (Mar. 28, 2018), eLibrary No. 20180328-5154 ("[O]ut of all of the proposed interconnection projects and their associated generation facilities, only a small fraction are likely to ever reach commercial operation."); MISO, Filing of Revisions to the Open Access Transmission, Energy and Operating Reserve Markets Tariff to Reform MISO's Generator Interconnection Procedures at 13, *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER17-156-000 (Oct. 21, 2016), eLibrary No. 20161021-5139 (proposing queue reforms because "MISO's queue currently includes many projects that remain only to minimize the cost of their eventual withdrawal."); Statement of Dean Gosselin, Vice President, Transmission Services, Business Management, NextEra Energy Resources, LLC, at 3, *Review of Generator Interconnection Agreements and Procedures*, Docket No. RM16-12-000 (May 16, 2016), eLibrary No. 20160516-4011("The majority of new generator interconnection requests submitted by developers will not lead to construction of projects.").

the development process, encourage rent-seeking behavior by incentive recipients that will undermine projects selected by the planning process, and erode the regional and regulatory trust needed get major transmission facilities approved, sited, and built.

While benefits-based incentives would be inappropriate, should the Commission pursue that approach, it should, at minimum, adopt general criteria that support the Order 890 and Order 1000 planning processes. *See* response to Q 5 subpart g.

10. Ownership by Non-Public Utilities (Q 50-51)

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

As discussed in Part II, the Commission has long recognized the benefits of public power participation in transmission ownership, and TAPS members have actively sought to invest in transmission to provide a hedge against increasing transmission rates. However, even with Order 1000's non-incumbent transmission developer reforms and the 2012 Policy Statement's treatment of public power investment among the risk-reducing measures incentive applicants are expected to consider,[245] progress has been limited.[246] TO resistance to joint ownership will only intensify if the Commission makes ROE incentives more readily available than under the 2012 Policy Statement.

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

As discussed in Part II, the Commission should fulfill its Sections 217(b)(4) and 219(b)(1) responsibilities, as well as its obligations to ensure the just, reasonable, and not unduly discriminatory rates required by Sections 219(d), 205 and 206, by retaining and strengthening the 2012 Policy Statement's inducement of joint ownership. Such

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[245] 2012 Policy Statement P 24.

[246] *See* Part II; TAPS White Paper at 5 n.6 (describing TAPS member offers to invest that have been rebuffed).

enhancement should be included in any incentives policy revision, but it is particularly critical if the Commission were to grant incentives based on benefits or characteristics, with higher ROE incentives increasing the transmission rates that TDUs must bear with no opportunity to hedge that increase through ownership. The grant of an ROE incentive to an applicant that refuses to consider—or worse yet, turns down—TDU offers to participate would be unduly discriminatory and inconsistent with the Commission's statutory obligations.

Specifically, the Commission should state definitively that evidence of such consideration of joint ownership with public power *is* relevant to the applicant's qualifications for incentives.[247] Applicants should also be required to state whether they are open to investment on reasonable terms by financially qualified TDUs located in the relevant footprint (e.g., the state or region), and depending on the answer, either explain why not or identify the criteria to qualify for participation. Where an applicant has not provided a meaningful opportunity for joint ownership on load-ratio basis to TDUs in the footprint that will bear the cost, there should be a rebuttable presumption that the applicant has not taken all appropriate steps to minimize its risks and that grant of the incentive does not accord with the FPA. Inclusion of TDU participants in the project would provide evidence of the meaningfulness of the offered opportunity.

If the Commission grants ROE incentives for less than fully independent Transcos, it should do the same for inclusive joint ownership arrangements described in Part II. Broad ownership participation has many of the governance benefits of a fully

[247] The Commission should revise footnote 33 of the 2012 Policy Statement to read: "Evidence regarding whether an applicant for incentives considered joint ownership arrangements is ~~may be~~ relevant in assessing whether the applicant took appropriate steps to minimize its risks during project development."

independent Transco, e.g., preventing one owner from steering the project in a direction that serves its generation interests.

11. Order No. 1000 Transmission Projects (Q 52-54)

Q 52) Should these or other incentives be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation?
Q 53) If so, what specific incentives are appropriate for such automatic treatment and how should such incentives be designed?

TAPS opposes automatic incentives. *See* response to Q 7. Limiting such treatment to risk-reducing incentives for projects selected for regional cost allocation pursuant to Order 1000 does not make automatic application appropriate.

The grant of the abandoned plant recovery incentive, while risk-reducing, will increase ratepayer costs in the event of project abandonment beyond the developer's control. It should continue to be limited to where it is needed to induce future action given the risks, as recently emphasized in *San Diego Gas & Electric Co. v. FERC*, 913 F.3d 127 (D.C. Cir. 2019) ("*SDG&E*").[248] Otherwise, it amounts to an unnecessary burden.

Even as to the risk-reducing incentives that principally affect the timing of rate recovery (i.e., CWIP and regulatory asset treatment), individual Commission evaluation serve an important function.[249] These incentives are not needed to support investment decisions in all cases.[250] For example, NextEra did not include CWIP or AFUDC in its

[248] *See, e.g.*, *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,304, P 24 (2014) (risk of PJM discontinuing project's selection in the regional planning process is not a project-specific risk justifying the incentive).

[249] As required by Order 679 and the 2012 Policy Statement, currently an applicant must demonstrate a nexus between the incentive and project risks to demonstrate that the incentive "materially affect[s] investment decisions." *See* Order 679-A P 25.

[250] *See, e.g., ATX Sw., LLC*, 152 FERC ¶ 61,193, P 48 (2015) (generalized claims that CWIP incentive will improve cash flow during construction and provide greater regulatory certainty is insufficient to demonstrate nexus, without showing the size of the effect of a project on cash flow that CWIP would elicit, details regarding its financial pressures, delayed cash flow, relative size of the proposed investment, or

successful bid to build MISO's Hartsburg-Sabine Junction 500 kV project.[251] It is not in the public interest to automatically authorize deviations from the Commission's cost-of-service ratemaking policies where they are not needed.

Treating incentives as automatic could remove, either by definition or in practice, the key step of ensuring the total package of incentives is appropriately tailored and is just and reasonable.[252] Given the relationship of risk-reducing incentives to the ROE warranted,[253] incentives must be evaluated together through case-by-case review.[254]

Given the Commission's track record of awarding risk-reducing incentives where justified on a project-specific basis, mitigation of that risk is insufficient to overcome the adverse impacts of automating incentives.

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?

As noted in the NOI (P 34 & n.40), the Commission has accepted proposals to provide non-incumbent transmission developers with certain incentives to promote a level playing field in the Order 1000 regional planning processes. These incentives include establishing hypothetical capital structures and regulatory assets to enable non-

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adverse impacts to short-term liquidity); *Transource Wis., LLC*, 149 FERC 61,180 PP 28-29 (2014) (CWIP incentive is premature without a project-specific showing of nexus, and is not necessary to placing non-incumbent transmission developers on a level playing field with incumbent transmission owners in the Order 1000 competitive solicitation process).

[251] MISO, *Selection Report: Hartburg-Sabine Junction 500 kV Competitive Transmission Project* at 21 (2018), https://cdn.misoenergy.org/Hartburg-Sabine%20Junction%20500%20kV%20Selection%20Report296754.pdf.

[252] *See* Order 679-A P 27; 2012 Policy Statement P 10.

[253] *See S. Cal. Edison Co.*, 112 FERC ¶ 61,014, P 61 & n.49 (2005).

[254] Project-specific filing facilitates application of other limitations that restrict incentives to just and reasonable levels, as Section 219 requires. For example, case-by-case review supports application of the 2012 Policy Statement's requirement (P 28) that incentives apply only to estimated cost levels.

incumbents to seek recovery of prudently incurred pre-commercial costs associated with bidding in an Order 1000 competitive process (and to accrue a carrying charge on that regulatory asset prior to its authorized recovery) on the theory that to do otherwise would unduly discriminate against non-incumbent developers (as compared with incumbent transmission owners that may expense their planning-related costs through their rates).

As discussed in response to Q 72-76, TAPS supports broadening the pool of project developers and allowing hypothetical capital structures for non-incumbent developers with appropriate limitations. But TAPS opposes regulatory asset treatment for unsuccessful competitive bid costs. It would be more appropriate to exclude *both* incumbent and non-incumbent developers from recovering those costs. If it is allowed, at minimum, carrying charges should be limited, and the treatment's cost impact should be made transparent in future bids so that it can be taken into account in evaluating them.

Incumbent TPs/TOs must meet NERC planning obligations, as well as tariff and RTO planning requirements, and should be able to recover the costs prudently incurred to meet those obligations.[255] But to assure comparability, to the extent that incumbents (or their affiliates) go beyond their required planning obligations and voluntarily compete for selection as more cost-effective and efficient projects, the incumbent's unsuccessful bid costs should be treated in the same way as unsuccessful non-incumbent bid costs.[256]

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[255] That is, TPs/TOs should not bear the risk that they will be prevented from recovering the costs of conducting the Order 1000 process, or planning and developing projects to meet these requirements—e.g., through inclusion of such projects in the underlying regional plan—even if others ultimately seek to compete to develop a more cost-effective and efficient alternative project through the Order 1000 process.

[256] A non-incumbent transmission developer includes an incumbent proposing a project outside its footprint. Order 1000-A PP 415-16 (citing Order 1000 PP 225, 253 n.231).

There is no need to incent unsuccessful bids. Requiring customers to subsidize unsuccessful bidders is likely to drive up the total cost of transmission, defeating Order 1000's purpose of more efficient and cost-effective solutions. In the Competitive Transmission Development proceeding, SPP described an instance in which eleven developers collectively spent between $3.3 million and $4.4 million to produce competitive bids for a project estimated to cost $8.3 million.[257] Allowing unsuccessful bidders to recover their bid development costs would have increased the total cost of that project by up to 50 percent, likely offsetting any consumer benefits from competition. To avoid encouraging bidders to incur development costs that far exceed any potential consumer benefits from competition (and spawning a cottage industry of poorly designed bids), ratepayer should not be required to subsidize unsuccessful bids.

If the Commission provides any opportunity for non-incumbent or TO recovery of unsuccessful bid costs for Order 1000 projects, it should be available only if: (1) the bidder subsequently submits a successful bid for a project that is selected for regional cost allocation through an Order 1000 process; (2) the costs from any prior unsuccessful bid(s) that the bidder seeks to recover have been fully disclosed and included in the subsequent, selected project's bid; and (3) the subsequent, selected project has commenced service. In addition, the carrying charge should be no higher than the minimum level that creates comparability to the incumbent TOs' expensing of

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[257] Paul Suskie, SPP, Prepared Statement for the Competitive Transmission Development Technical Conference at 2, Docket No. AD16-18-000 (June 30, 2016), eLibrary No. 20160630-4036. Of the estimated $4 million – 5 million in SPP and developer costs, approximately $3.3 million – 4.4 million was spent by competing developers, while over $500,000 was spent by SPP to administer the process and evaluate the developer submissions. After the selection process was completed, the project was cancelled based on reassessment of need. *See also* Tom Kleckner, *SPP Cancels First Competitive TX Project, Citing Falling Demand Projections*, RTO Insider (July 18, 2016), https://www.rtoinsider.com/spp-ferc-order-1000-transmission-demand-projections-28978/.

transmission planning labor and the related expenses. At most, such carrying charges should be accrued at an AFUDC rate, with substantial short-term debt included in the carrying charge rate computation.

12. Transmission Projects in Non-RTO/ISO Regions (Q 55-56)

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

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

It is unclear why developers of transmission projects in non-RTO regions have requested incentives less often. The level of incremental transmission investment in non-RTO areas is generally lower than in RTOs, so there may be fewer projects facing risks and challenges warranting incentives.[258] In addition, public utility TPs in non-RTO areas might find transmission development less risky—perhaps because major transmission projects are more closely tied to their own planned generation. Since non-public utility TPs typically would not apply to the Commission for transmission incentives, it is not unexpected that there would be fewer applications from non-RTO regions where a significant share of the grid is owned by such entities.

Increasing incentives is not an appropriate way to encourage the development of new transmission in non-RTO areas. The Commission's goal should not be more transmission investment, but investment in the *right* transmission facilities. The best way to achieve that goal would be to take steps to improve existing Order 890 and Order 1000 transmission planning processes. *See* responses to Q 5 subpart g and Q 44-46.

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[258] *See, e.g.*, Brattle Group Order 1000 Discussion Paper at 7 (showing a 14% growth in U.S. Annual Transmission Investments in RTO areas, in contrast to 6% for Western Electric Coordinating Council excluding CAISO, and 10% for the Southeast); 2017 Transmission Metrics Report at 48 (showing SERC Reliability Corporation and Florida Reliability Coordinating Council as having the lowest Load-Weighted Circuit Miles of Transmission added between 2008-2015 (data for the Pacific Northwest and the Southwest were aggregated with data for the CAISO and are not separately reported)).

It may be particularly important to revisit the design and performance of Commission-required transmission planning processes in non-RTO areas. Based on the experience of TAPS members, Order 1000's non-incumbent developer reforms may have had perverse effects in at least some non-RTO areas. There are indications that TOs seeking to avoid non-incumbent competition have become more secretive about their long-term plans, and are focusing on local reliability projects needed within the next few years (thus exempted from potential competition or displacement in Order 1000 processes). This undermines development of regional projects and makes planning *less* open, transparent, and collaborative than pre-existing Order 890 processes. The solution is for the Commission to renew its commitment to assuring that TPs provide stakeholders with a meaningful opportunity to participate in local and regional planning.

C. *Existing Incentives*

1. ROE-Adder Incentives

a) Transmission-Only Companies (Q 57-60)

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?

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?

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

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

As summarized in the NOI (P 37), Order 679 provided for an ROE incentive to encourage stand-alone transmission-only companies, with the hope that such companies would bring a singular focus on transmission expansion, free from the competition for capital between generation and transmission functions and the potential for discrimination. Although this incentive was not identified in Section 219, its authorization was intended to help address the then-pressing need to reverse the long-term decline in transmission investment. *See* response to Q 1.

The situation is very different today. First, as discussed in response to Q 1, a torrent of capital now seeks to invest in transmission. Few other investments offer the assurance of cost recovery through formula rates that include a FERC-regulated ROE. Utilities are fighting for the opportunity to construct transmission and tout these investments' secure nature to investors. They have been retiring, not adding, baseload units; competition for capital with the generation function seems much less pressing.

Second, the Order 1000 competitive solicitation process, properly implemented, should ensure that if Transcos' business model makes them better at transmission development, they will prevail on the merits. An adder is not needed to facilitate such participation. Other incentives (e.g., hypothetical capital structure, regulatory asset treatment) enable newly formed transmission companies to participate in such processes,[259] where competition has been robust.[260] Indeed, inclusion of an ROE adder in the Transco's competitive bid may make it less likely to be selected.

Third, as time has passed, the inherent advantages of organizing transmission ownership through a Transco have become more evident—including having the Transco's rates subject to regulation by a single regulator (this Commission) that assures cost recovery plus a Commission-approved ROE. Consequently, many vertically-integrated holding companies have formed transmission-only subsidiaries.[261]

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[259] *See* responses to Q 54, 72.

[260] *See* response to Q 1.

[261] *See, e.g.*, *AEP Appalachian Transmission Co., Inc.*, 165 FERC ¶ 61,092 (2018); *N.Y. Indep. Sys. Operator Inc.*, 151 FERC ¶ 61,004 (2015).

Fourth, this trend toward affiliated Transcos has heightened the challenges of assessing eligibility. Although Order 679 did not categorically disqualify affiliates of public utilities, it made clear that the Commission would consider whether a particular Transco qualified based on its characteristics.[262] The Commission has denied an adder for a Transco composed of affiliates of major market participants on the grounds it was not sufficiently independent.[263] While current Commission policy is to grant a 50 basis point adder for independent Transcos,[264] it recently reduced to 25 basis points, but did not eliminate previously-allowed adders as a result of reduced independence.[265]

The task of assessing the impact on Transco decision-making of increasingly complex and sprawling corporate structures, with parents or affiliates in markets that are increasingly interrelated, is only getting harder. Even if the Transco itself is purely transmission-focused and independent of generation entanglements, where it is part of a larger holding company, the Transco's investment decisions will be subject to competition for capital with other opportunities;[266] if the holding company has generation interests, those may tilt the scales.

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[262] Order 679 PP 201-02.

[263] *See, e.g., N.Y. Sys. Operator Inc.*, 151 FERC ¶ 61,004, P 92 (2015).

[264] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,252, P 45 (2015), *on compliance, clarification and reh'g*, 154 FERC ¶61,004 (2016) (granting a 50 basis point adder for ITC Midwest, finding a "50 basis points is an appropriate size for the Transco Adder," and "strikes the right balance by appropriately encouraging independent transmission consistent with Order No. 679, while acknowledging . . . concerns regarding the rate impacts of such adders."); *NextEra Energy Transmission N.Y., Inc.*, 162 FERC ¶ 61,196 (2018) (similar). The Commission had earlier granted 100 basis point independent Transco Adders. *ITC Holdings Corp.*, 102 FERC ¶ 61,182, P 68 (2003); *Mich. Elec. Transmission Co., LLC*, 113 FERC ¶ 61,343, P 17 (2005), *order on reh'g*, 116 FERC ¶ 61,164 (2006).

[265] *Consumers Energy Co. v. ITC Transmission Co*., 165 FERC ¶ 61,021, PP 1, 73-74 (2018), *reh'g pending*.

[266] For example, the decision whether to retain earnings in the Transco subsidiary or pay them out to the holding company parent will be made by that parent, based on competition for capital between transmission and the holding company's other opportunities. Capital is inherently fluid and fungible, and will be

The Commission should therefore reassess the Transco Adder. To the extent an adder is still warranted, it should be limited to fully independent Transcos—those "independent of any entity whose economic or commercial interests could be significantly affected by the RTO's actions or decisions."[267] However, TAPS urges against any adder where there is less than full independence. Providing adders to less-than-fully-independent Transcos emphasizes form over substance, incentivizing corporate structures that remain exposed to market participant influence over transmission investments. Because such Transcos are less likely to plan and invest in transmission independent from their affiliates' directives,[268] an adder would increase costs without offsetting benefits. Limiting the Transco Adder to fully independent transmission entities will avoid fine-line determinations on the extent to which the influence of market participant affiliates compromises the intended benefits of such structures.

On the other hand, particularly if the Commission continues to allow adders for Transcos that are not fully independent, it should grant incentives for fully inclusive Transcos (where all LSEs in the footprint have an opportunity to participate in ownership on a load ratio basis). Bringing all LSEs in the footprint to the table as owners facilitates inclusive planning and expansion of the grid to meet the needs of all LSEs, avoiding

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directed to the most rewarding opportunities.

[267] Order 2000 at 31,061. *Compare ITC Holdings Corp.*, 102 FERC ¶ 61,182, P 43 (2003) *with S. Cent. MCN LLC*, 153 FERC ¶ 61,099, P 67 (2015).

[268] *See Consumers Energy Co. v. Int'l Transmission Co.*, 165 FERC ¶ 61,021, PP 68-73 (finding reduced level of independence due to ITC's merger with Fortis Inc. and GIC Ventures Private Limited, although granting a reduced Transco Adder), and Commissioner Glick *dissenting*, PP 4-6 (detailing the potential for influence).

concerns about discrimination, facilitating siting, and delivering the benefits expected when Order 679 authorized the Transco incentive.[269]

Finally, where allowed, the Transco Adder should be limited in two additional ways. First, each entity that receives a Transco Adder should do so only for a limited period, such as the five-year period that generally applies to customer hold-harmless protections in the merger context.[270] If five years is sufficient to protect consumers, it should be sufficient to incent investors. Second, the Transco Adder should apply only to new facilities, consistent its purpose of incenting new investment. Applying the adder to acquired facilities raises costs without delivering value to consumers.

b) RTO/ISO Participation (Q 61-66)

Q 61) Should the Commission revise the RTO-participation incentive?
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?
Q 63) If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?
Q 64 Should the RTO-participation incentive be awarded for a fixed period of time after a transmission owner joins an RTO or ISO?
Q 65) Should the RTO-participation adder be awarded on a project-specific basis?
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?

i. The RTO Adder is ripe for revision (Q 61, 63-66)

When Congress enacted Section 219 to provide incentives to utilities that join RTOs, RTOs were in their infancy.[271] Order 679 established the RTO Adder, in

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[269] *See* response to Q 51 for other mechanisms the Commission should use to strengthen its encouragement of inclusive joint ownership arrangements, given the benefits described in Part II.

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

[271] "For example, ISO-NE and SPP were approved as RTOs in 2004. *See ISO New England Inc.*, 106 FERC ¶ 61,280, P 3 (2004); *Sw. Power Pool, Inc.,* 109 FERC ¶ 61,009, P 15 (2004). While some RTOs

"recognition of the benefits that flow from membership" and the fact [that] continuing membership is generally voluntary." Order 679 P 331. Although determinations are to be made on a case-by-case basis,[272] the Commission has granted 50 basis point adders to those that have joined and remain a member of an RTO without regard to voluntariness of participation, an approach recently found arbitrary by the Ninth Circuit.[273]

Circumstances have changed dramatically. The six RTOs have now been in existence for nearly two decades, are more developed and well-entrenched, with many benefits, and cover a much-expanded footprint. Currently, "two-thirds of the nation's electricity load is served in RTO regions."[274] As a result, the RTO Adder's impact on the nation's businesses and consumers is enormous. The direct cost of a 50 basis point ROE adder is roughly $400 million per year, and growing.[275] The Commission should

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had been acting as TPs for years, the wholesale markets and services currently offered by RTOs were still in development in 2005. *See, e.g.*, *Devon Power LLC*, 115 FERC ¶ 61,340 (2006) (approving settlement establishing ISO-NE's Forward Capacity Market); MISO, *MISO History*, https://www.misoenergy.org/stakeholder-engagement/training2/learning-center/miso-history/ (last visited June 24, 2019) (MISO launched its Energy Markets 2005, and launched its Ancillary Services Market in 2009).

[272] Order 679 P 326 (declining to adopt a generic adder for RTO membership); *id.* P 327 ("We will not make a generic finding on the duration of incentives that will be permitted for public utilities that join Transmission Organizations.").

[273] *See, e.g.*, *CPUC 2018*, 879 F.3d at 971-72 (remand pending).

[274] FERC, *Electric Power Markets: National Overview* (Apr. 10, 2019), https://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

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

reevaluate the RTO Adder in light of these developments to ensure it is tailored to incentivize future, voluntary behavior without saddling ratepayers with undue burden.

ii. RTO Adders should be limited to no more than ten years (Q 64)

A TO eligible for the RTO Adder should be permitted to collect it for no more than ten years, inclusive of any years when that TO participated in a different RTO, or when a predecessor owner of the recipient's transmission system participated in an RTO.

Although the Commission in Order 679-A (P 86) provided that the RTO Adder would "effective for the entire duration of a utility's membership in the [RTO]," rewarding participants for not withdrawing from RTOs has become less justified with the passage of time, as TOs have become well-rooted.[276] As RTO services have grown, so too have the non-ROE incentives to remain in an RTO. A TO may do so to ensure continued access to RTO markets (with the TO's authority to make market-based sales generally evaluated on an RTO-wide basis).[277] The Commission is proposing to enhance that advantage by eliminating the need for those in RTOs to submit market power screens in many cases.[278] There are other benefits as well—MISO, for example, estimates

with-tax, 2019 estimate of the adder's nationwide annual direct cost to consumers: $412,603,277.

[276] Some may be subject to commitments and state approval processes limiting withdrawal. *See CPUC 2018*, 879 F.3d at 971.

[277] *See* Order 697 PP 231, 235. Outside RTOs, market power screens focus on the seller's balancing authority area and first tier balancing authority areas (*id.* at P 232), a test that can be challenging for vertically integrated utility.

[278] *See generally Refinements to Horizontal Mkt. Power Analysis for Sellers in Certain Reg'l Transmission Orgs. & Indep. Sys. Operator Mkts.*, 165 FERC ¶ 61,268 (2018) (proposing elimination of the requirement that sellers submit indicative market power screens for RTO markets with RTO-administered energy, ancillary services, and capacity markets subject to Commission-approved monitoring and mitigation).

approximately $3.5 billion in annual benefits associated with improved reliability, market commitment and dispatch, and generation investment deferral.[279]

As described in subpart i, the cost burden associated with the RTO Adder is very significant, amplifying the already heavy burden of rising transmission costs.[280] In light of the additional inducements to continued RTO membership, it is unreasonable to saddle customers in perpetuity with an unnecessary 50 basis point RTO Adder.

Accordingly, the Commission should limit the RTO Adder's duration and/or level. Restricting collection of the adder to no more than ten years from the date the TO (or its predecessor) initially joined an RTO strikes the appropriate balance between incentivizing TOs to join RTOs and ensuring incentives are not unduly burdensome.[281] Ten years is sufficient for a TO to fully integrate into an RTO and participate in several planning cycles, and is on par with the Commission's initial thinking regarding RTO Adders.[282] A time-limited adder is consistent with Section 219(c)'s mandate to provide an incentive *for joining* an RTO; it does not require an incentive *for remaining* in an RTO. If Congress had intended the incentive be permanent, it would have so required.

iii. RTO Adders should be subject to case-by-case assessment of voluntariness (Q 66)

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[279] MISO, *Value Proposition*, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ (last visited June 24, 2019).

[280] *See* response to Q 1.

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

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

The RTO Adder should be limited to TOs whose RTO participation is voluntary. Voluntariness is a core principle of incentives.[283] "An incentive cannot "induce" behavior that is already legally mandated."[284]

As the Ninth Circuit recently explained, Orders 679 and 679-A "did not make ongoing membership in a transmission organization the sole criterion for an incentive adder, and the orders did not preclude challenges based on the voluntariness of a utility's membership in a transmission organization."[285] Granting the RTO Adder where a TO is obliged to join or remain in the RTO increases costs without providing a benefit—commensurate or otherwise—and constitutes a windfall rather than a spur to motivate conduct. Where voluntariness is raised as an issue, the Commission should engage in a case-specific inquiry, and deny or revoke recovery of the RTO Adder where voluntariness is not demonstrated.[286]

iv. No additional RTO-participation incentives are necessary or appropriate (Q 62)

The Commission should not award incentives in addition to a time-limited and/or reduced RTO Adder. Project-based incentives, such as CWIP or abandoned plant, should be awarded on a case-by-case basis where warranted to reduce risks and challenges faced

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[283] *See, e.g.*, 1992 Policy Statement at 61,599 ("A 'reward' for past behavior" after all "does not induce future efficiency and benefit consumers."). *See* response to Q 5 subpart a.

[284] *CPUC 2018*, 879 F.3d at 974. *See also SDG&E*, 913 F.3d at 137-38 (the Commission's long-standing policies (which the court had previously accepted) that incentives must induce prospective behavior). *See also* response to Q 5 subpart a.

[285] *CPUC 2018*, 879 F.3d at 974.

[286] Application of a ten-year limitation on the RTO Adder would reduce the need to assess continued voluntariness as to many TOs currently collecting the RTO Adder.

by a project that provides benefits covered by Section 219, not automatically as an additional incentive for continued RTO participation.[287]

c) Advanced Technology (Q 67-69)

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.

TAPS supports the 2012 Policy Statement's treatment of incentives for advanced technologies. *See* response to Q 37-40. Given the near-certainty of cost recovery with Commission-approved ROEs, and the absence of siting risk, TOs may well have found incentives unnecessary to induce such technology investments.[288]

To the extent there is a concern that NERC Reliability Standards create unnecessary barriers to advance technologies, the standards should be modified. With the potential for $ 1 million/violation/day penalties, compliance risk is real. TAPS supports the Standards Efficiency Review, which NERC has undertaken with stakeholders to "[e]valuate NERC Reliability Standards using a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard Requirements." [289]

2. Non-ROE Transmission Incentives

a) Regulatory Asset/Deferred Recovery of Pre-Commercial Costs and CWIP (Q 70-71)

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[287] *See* response to Q 7. *See also* response to Q 52-53.

[288] *See* EEI White Paper, noting the need for "predictable, sustainable, and reasonable returns to balance the [planning, siting and construction] risks inherent in [transmission] investment" to attract capital for such investments transmission (at 2), and providing "[r]eal examples of innovative transmission technologies" that EEI members have employed (at 8), presumably without incentives.

[289] NERC, *Standards Efficiency Review*, https://www.nerc.com/pa/Stand/Pages/Standards-Efficiency-Review.aspx (last visited June 25, 2019).

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?

TAPS generally supports the Commission's current policies regarding awarding 100 percent of CWIP in rate base and recovery of 100 percent of pre-commercial costs as an expense or as a regulatory asset where warranted to address risks and challenges.[290] The grant should remain case-by-case, ensuring their impact on required ROE is considered in determining if the total package of incentives is tailored to the risks and results in just and reasonable rates. Order 679 (P 116) allowed departure from the Commission's general ratemaking policy (permitting up to 50% of CWIP in ratebase) where justified on a case-by-case basis because "[t]he nation has suffered a decline in transmission investment," while "ensuring that customers are protected and rates remain just and reasonable." Particularly given today's increasing transmission investment (*see* response to Q 1), automatic application of CWIP and regulatory asset incentives fails to balance consumer and investor interests, as the FPA requires.[291]

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. *See* response to Q 54.

b) Hypothetical Capital Structure (Q 72-76)

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?

Hypothetical capital structures benefit consumers, and are therefore reasonable, where they result in lower rates than would result from strict adherence to actual capital structures. There are two groups of entities for which this is the case.

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[290] *See* responses to Q 1, 2, 7, and 52-53, *but see also* response to Q 54 regarding unsuccessful bid costs.

[291] *See* Order 679 PP 116-17.

First, entities formed as special-purpose entities to sponsor a new transmission project commonly start with actual capital structures consisting entirely of equity, because they cannot sell bonds until their assets are constructed and placed into service. Hypothetical capital structures for such entities benefit consumers directly by reducing their equity ratio, and more broadly by "facilitating the participation of nonincumbent transmission developers in Order No. 1000 transmission planning processes, thereby encouraging competition."[292]

Second, hypothetical capital structures are often essential to public power participation in major transmission projects, and thus similarly "facilitate[s] the participation of non-incumbent transmission developers."[293] Public power entities are typically 100% debt financed, and their debt generally is tax-exempt and has exceptionally high credit ratings, resulting in exceptionally low interest rates. At first blush, it might seem that consumers would be benefited by requiring that public power transmission owners use a ratemaking capital structure consisting entirely of 100% long-term debt, and use the average yield on that debt as their weighted average cost of capital. But rates set on that basis would fail to support the debt coverage ratios (sometimes formally specified in bond covenants, sometimes set as a matter of board policy, but in either case relied upon by bond rating agencies in rating public power bonds) that enable public power TOs to use low-cost debt financing. *See* Part II.

If public power TOs were not allowed to use hypothetical capital structures in appropriate cases, their facilities would instead go unbuilt or be built and owned by

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[292] *GridLiance Heartland LLC*, 166 FERC ¶ 61,067, P 46 (2019); *S. Cent. MCN LLC*, 153 FERC ¶ 61,099, P 37 (2015) (same).

[293] *GridLiance Heartland LLC*, 166 FERC ¶ 61,067, P 46 (2019).

investor-owned utilities. Neither alternative would benefit consumers. Little need be said about why the no-build alternative would harm consumers: clearly, where an appropriate planning process has determined that a facility should be built, failing to do so will leave its value unrealized. As to the other alternative, public power participation in transmission ownership benefits ratepayers in multiple ways. Public power utilities are not subject to income taxes, and they flow their tax savings through to transmission ratepayers. Their lower debt cost further reduces rates. Even when set on a hypothetical basis, the capital structures of not-for-profit public power utilities commonly include less equity than investor-owned utilities' actual capital structures. Their participation in siting processes and associated political processes eases and speeds siting, and their RTO participation broadens RTOs' geography and deepens their markets.

Consistent with Section 219(b)(1)'s objective of promoting transmission investment "regardless of the ownership," the Commission has rightly allowed the use of hypothetical capital structures (justified as appropriately reflecting what is required for achievement of debt coverage ratio) as an incentive treatment that facilitates public power participation in transmission ownership.[294] The Commission should continue to allow hypothetical capital structures where justified on a case-by-case basis.

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[294] *See Midcontinent Indep. Sys. Operator, Inc.*, 152 FERC ¶ 61,019, P 22 (2015) ("The requested hypothetical capital structure will bolster Dairyland's financial metrics, help ensure its strong credit rating, and enable its participation in the Badger-Coulee Project."); *Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,263, P 25 (2013) ("… Central Minnesota has demonstrated that its hypothetical capital structure will address Central Minnesota's risks and challenges related to its credit metrics including the DSC ratio and its lack of assets. We find that the hypothetical capital structure will assist in providing cash flows needed to meet Central Minnesota's required project-specific debt service coverage ratios and project-specific credit rating. Accordingly, we will grant Central Minnesota use of a hypothetical capital structure for the Project's entire financing period, and we find use of the proposed 50 percent equity and 50 percent debt appropriate"); *Mo. River Energy Servs.*, 138 FERC ¶ 61,045, PP 38-39 (2012) ("denial of Missouri River's request [for a hypothetical capital structure of 45 percent equity and 55 percent debt] would decrease Missouri River's cash flow, reduce Missouri River's ability to make payments on its debt, and

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

Although TAPS has not conducted an empirical study on this issue, it would be unlikely for hypothetical capital structures to reduce the issuer's actual debt cost. Debt investors are concerned with the *actual* capital structures of the entities in which they invest, as those actual capital structures identify how much lower-bankruptcy-priority equity stands behind each dollar of long-term debt.

Nonetheless, allowing public power to apply a hypothetical capital structure for ratemaking can reduce the debt costs paid by consumers. Such ratemaking treatment enables ratepayers to benefit from public power's low tax-exempt debt cost and displaces the higher-cost debt and equity financing, and tax allowances, of for-profit entities.

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?

Hypothetical capital structures should not be transferrable to a yet-to-be-formed affiliate without Commission review. Different entities have different capital structures, risks, and debts. Accordingly, a request for a hypothetical capital structure should be evaluated in the case-specific context of the entity to which it will apply, and the Commission should not issue a "blank check," to be drawn on ratepayers' account, that would authorize a hypothetical capital structure for an entity with unknown characteristics. However, advance approval for such treatment may become appropriate before the future entity is actually formed, provided its relevant characteristics are known. Accordingly, where a hypothetical capital structure can be justified for an

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hinder Missouri River's ability to reach its targeted actual capital structure of 40 percent equity and 60 percent debt," whereas "[a]pproving the Hypothetical Capital Structure for the entire period of debt financing will benefit Missouri River's credit rating and allow it to receive more advantageous financing terms, which decrease the total cost of its investment in the Fargo and Brookings projects").

anticipated (albeit not-yet-formed) entity for which the relevant characteristics can be specified, the future entity's existing affiliates may be able to demonstrate that the future entity should be granted a hypothetical capital structure, and obtain a declaratory order or other ruling to that effect.

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

Such extension is appropriate in two situations. First, it would be appropriate in the public power situation (*see* response to Q 72-73). Second, where the entity applying an approved hypothetical capital structure has not yet issued long-term debt in an amount sufficient to reduce its equity ratio below the hypothetical level, and that non-issuance is consistent with representations made to the Commission and with prudent management.

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)?

The justifiable hypothetical equity ratio depends on case-specific facts, such as whether that entity has transmission assets in service and the entity's actual equity ratio. Accordingly, the Commission should not generically bound all hypothetical equity ratios by a hard floor or ceiling. However, a rebuttable presumption could guide stakeholders and simplify Commission proceedings. The actual capital structures of public utility TOs are generally about 55% equity, while their publicly-traded parents are generally about 45% equity.[295] Averaging those percentages and rounding, the Commission should apply a rebuttable presumption that a hypothetical capital structure with 50% equity contains sufficient equity. However, this presumption should be rebuttable. On a case-specific

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[295] *See, e.g.*, CAPS' Paper Hearing Principal Initial Brief, Ex. No. CAP-4310, *Coakley v. Bangor Hydro-Elec. Co.*, Docket No. EL11-66 (Jan. 11, 2019), eLibrary No. 20190111-5238 (comparing the New England Transmission Owners' capital structures to capital structures of the companies in the proxy group).

basis, applicants seeking a larger hypothetical equity ratio may be able to justify one, and, conversely, a 50% equity ratio may be found to be excessive in certain cases.

c) Recovery of the Cost of Abandoned Plant (Q 77-79)

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?

Case-by-case evaluation is essential for the abandoned plant incentive which, while reducing risk, may raise consumer costs. *SDG&E* affirmed Commission application of its abandonment incentive "prospectively[] to investment that had yet to occur," rejecting San Diego Gas & Electric's request to recover from ratepayers 100% of the costs prudently incurred prior to the Commission's decision in the event of a qualifying abandonment.[296] The court found that the limitation aligned with long-standing Commission policies (which the court had previously accepted) that incentives must induce prospective behavior.[297] In rejecting arguments for more automatic application, the court highlighted the role of case-by-case assessment of the need for this incentive, and to reconcile its grant with other incentives requested.[298]

The relationship between the abandoned plant and ROE incentives confirms that case-by-case review is necessary to assessing whether the total package of incentives is tailored to risks and challenges and is just and reasonable. *See* 2012 Policy Statement P 16. The Commission has long recognized that the assurance of recovery of prudent

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[296] *SDG&E*, 913 F.3d at 130. *See generally* response to Q 7.

[297] *SDG&E*, 913 F.3d at 137 (quoting the 1992 Policy Statement at 61,599 ("'A reward for past behavior'" after all "'does not induce future efficiency and benefit consumers'")).

[298] *Id.* at 140. *See also id.* at 139 (analogizing to low mortgage rates encouraging home ownership, "[b]ut not every applicant is automatically entitled to every generally available deal"). *See generally* response to Q 52-53, citing *PJM Interconnection L.L.C.*, 155 FERC ¶ 61,304, P 24 (2016).

abandoned plant costs may warrant a lower ROE,[299] and stressed the importance of case-by-case evaluation in that regard.[300]

Finally, by shifting all project development cost risks to ratepayers, automatic application of this incentive could induce investment in unrealistic projects. That outcome will not benefit consumers and should be rejected.

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?

If the Commission maintains case-by-case application and evaluation for this incentive, and the total package of incentives to assess the need for ROE incentives consistent with the 2012 Policy Statement, TAPS supports the continued availability of up to 100% of prudently incurred abandoned plant costs where the project's abandonment is beyond applicant's control. But if the Commission moves to automatic application of this incentive, it should *not* continue at the 100% level. Rather, a lower coverage figure is needed to mitigate the developer's incentive to use ratepayer money to pursue unnecessarily risky projects or take unnecessary risks in transmission development.[301] Failure to get that percentage right will not only unduly burden the consumers that Section 219 is intended to benefit, but will impose real costs on other stakeholders. For example, incentive-fueled pursuit of a later-abandoned project may derail alternative transmission projects and disrupt generation developers that relied on the project entering service.

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[299] *See S. Cal. Edison Co.*, 112 FERC ¶ 61,014, P 61 (2005).

[300] *See* Order 679 P 167. *See also* Order 679-A P 66.

[301] The Commission may want to consider whether higher coverage is warranted for a project selected through the Order 1000 process, because that selection reduces the risk of an unnecessarily risky project.

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

Consistent with current policy, [302] recovery of abandoned plant cost will entail a separate Section 205 filing at the time the project is abandoned in which the applicant must demonstrate that the incurrence of abandoned plant costs was prudent, as well as showing that the abandonment was beyond its control, and that the proposed rate and amortization period are just and reasonable. Prudence of the costs incurred is a fact-specific inquiry that will require a hearing process (with discovery), particularly if the filing is contested. No short-cut of FPA procedures is appropriate. If the incentive is granted automatically, without case-specific review that the project merited incentives, the burden on the applicant to demonstrate the prudence of costs incurred to pursue the project and that abandonment was beyond its control would necessarily be higher.

d) Accelerated Depreciation (Q 80-82)

Q 80) Should the Commission continue to consider accelerated depreciation as an incentive?
Q 81) Does the accelerated deprecation incentive provide meaningful benefits to transmission developers?
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 comments leading up to Order 679, TAPS opposed accelerated depreciation, raising concerns about intergenerational inequity and undue burden on near-term consumers (which may increase siting challenges). We also pointed to long-term negative impacts; once a long-lived facility is fully depreciated over a short period, the TO will receive no return of or on its investment, which it must still operate and maintain. Order 679 allowed requests for this incentive (which it had previously granted in limited

[302] Order 679 P 166. *See United Illuminating Co*., 167 FERC ¶ 61,126, P 42 (2019).

circumstances),[303] but cautioned that applicants will be required to demonstrate a need for the additional cash flow as nexus. Order 679 PP 148-49. Since then, the incentive has been requested in few cases,[304] confirming its limited value.

TAPS continues to oppose accelerated depreciation. If it continues to be offered, requests must be considered under the risk and challenges approach. This incentive would be completely unjust and unreasonable if divorced from a case-by-case demonstration that the accelerated cash flow achieved by the particular depreciation period requested is needed for and tailored to risks posed by the proposed project.

D. Mechanics and Implementation

1. Duration of Incentives (Q 83-89)

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?

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?

The duration of various incentives should be limited. The length of project-based ROE incentives should be determined on a case-by-case basis, capped at a maximum of ten years, with directives to sunset at that time. Ten years strikes an appropriate balance between investor and consumer interests. Section 219 does not require life-of-project incentives, and given the competition to build (*see* response to Q1), there is no reason to believe that TOs or developers require longer incentives. *See* response to Q 5 subpart d.

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[303] *W. Area Power Admin*., 99 FERC ¶ 61,306 (2002), *aff'd sub nom*, *CPUC 2004*, 367 F.3d 925 (accelerated depreciation found necessary for Trans-Elect's participation). *Cf. Removing Obstacles to Increased Elec. Generation and Nat. Gas Supply in the W. U.S.*, 94 FERC ¶ 61,272, at 61,967-68 (2001) (to address "the electricity crisis facing California and other areas of the West . . . ," accelerated depreciation available for projects that will shortly be placed in service).

[304] *Westar Energy, Inc.*, 122 FERC ¶ 61,268 (2008) (15-year accelerated depreciation for one transmission line).

In addition, any Transco Adder should be time-limited (e.g., five years) (*see* response to Q 57-60), and RTO Adders should extend no more than ten years from the date the TO (or its successor) initially joined an RTO (*see* response to Q 61-66).

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?

To protect the integrity of the program, incentives must be subject to elimination or reduction if a project is materially changed. The Commission has previously denied implementation of ROE incentives where there were material changes from the project on which the incentive award had been based.[305] If the incentives are based on evaluating benefits, it becomes even more critical that the Commission be informed of material changes in the project and for it to reduce or eliminate incentives if warranted.

As discussed in response to Q 5 subpart b, before incentives are implemented, the applicant must make a Section 205 filing with the project's actual costs (including the incentive) and demonstrate (using the benefits calculation on which the Commission awarded incentives) that the project achieves the benefits-to-cost ratio assumed in the grant. If the project changed from that described in the original application, those changes must be identified, so that the Commission may assess their materiality and rescind or reduce the incentives *before* they are implemented.[306]

In addition, the Commission should ensure that consumers pay no incentives for projects other than the one they were promised. For example, applicants could be required to timely file a notification of a material change, subject to notice and

[305] *See Midcontinent Indep. Sys. Operator Inc.*, 164 FERC ¶ 61,155, PP 1, 22 (2018), discussed in response to Q 44-46.

[306] Material changes cannot increase previously awarded incentives. *See* response to Q 86-89.

intervention,[307] on which the Commission can take action to rescind or reduce the incentive. In any case, material changes should be defined to err on the side on reporting, so the Commission and the public can assess whether the project continues to merit the incentive.

Q 86) Should there be a process of measurement and verification (or audit) to determine if the expected benefits accrued to consumers?
Q 87) If so, how should measurement and verification take place and over what time period?
Q 88) Should the Commission consider eliminating an incentive if the project fails to realize its anticipated benefits?
Q 89) Should there be reporting on projects' expected benefits compared to results, and over what time period?

If incentives are based on benefits, multi-pronged measurement and verification is required. First, before incentives are implemented applicant must make a Section 205 filing with the project's actual costs (including the incentive) and demonstrate (using the benefits calculation on which the Commission awarded incentives) that the project achieves the benefits-to-cost ratio assumed in the grant.[308]

Second, as discussed in response to Q 5 subpart d and Q 83-84, ROE incentives should be restricted to no more than ten years. If the Commission does not do so, it has a duty to periodically reevaluate whether the project is actually delivering at least the claimed benefits on which the incentives are premised throughout the duration of the incentive.[309] Thus, where a benefits-based ROE incentive is awarded for more than ten years, every five years from when the project goes into service until it is removed from

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[307] *See, e.g.*, 18 C.F.R. § 35.42 (change in status report required within 30 days of a change in facts relied up in market-based rate authorization); *Material Changes in Facts Underlying Waiver of Order No. 889 and Part 358 of the Commissions Regulations*, 127 FERC ¶ 61,141 (2009) (public utilities must notify the Commission of material changes in facts underlying a standard if conduct waiver within 30 days).

[308] *See* responses to Q 5 subpart b and Q 85. Benefits would not be recalculated at the juncture unless there is a material change warranting reduction or elimination of the incentives. *See* response to Q 85.

[309] And it should do so in relation to the project's actual costs. *See* responses to Q 5 subpart b and Q 8.

ratebase and incentive ends, the Commission should require the recipient to submit a filing verifying that the project is producing no less than the benefit claimed in the original request for incentives. The recipient should use the methodology used in its original proposal or, if different, the methodology used by the Commission in granting the incentive. Like material change in status filings (*see* response to Q 85), the filing must be noticed for intervention, and can trigger revocation or reduction of incentives if at least the level of benefits on which the incentives were granted do not continue to be produced.[310] Because the actions intended to be induced—project construction—will have already occurred, incentives can never be increased.[311]

2. Case-by-Case vs. Automatic Approach in Reviewing Incentive Applications (Q 90-92)

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?
Q 91) If so, how could the Commission determine which incentives should be awarded automatically?
Q 92) If the existing case-by-case approach to incentives is retained, could it be improved? If so, how?

TAPS supports the Commission's case-by-case approach, and opposes automatic incentives. The case-by-case approach, which has been relatively efficient,[312] and is necessary to ensure sufficient nexus between requested incentives and the project's risks

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[310] If material issues of fact are raised, an evidentiary hearing with discovery may be required.

[311] An incentive must be prospective; the Commission cannot grant an incentive for action that has already occurred. *See, e.g.*, *SDG&E*, 913 F.3d at 137-38 (under the Commission's long-standing policies (which the court had previously accepted), incentives must induce prospective behavior); 1992 Policy Statement at 61,599 ("A 'reward' for past behavior" after all "does not induce future efficiency and benefit consumers.").

[312] *See, e.g.*, *United Illuminating Co.*, Docket No. ER19-1359-000 (United Illuminating Co., Application for Transmission Rate Incentives (Mar. 15, 2019), eLibrary No. 20190315-5249; *United Illuminating Co*., 167 FERC ¶ 61,126 (2019) (60 days between application filing and Commission decision)).

and challenges, that the total package of incentives is tailored to address those risks and is just and reasonable, and determine if various incentive requirements are satisfied.[313]

Benefits-based incentives would heighten the need for a case-by-case approach. The Commission's evaluation of the claimed benefits (and costs) is particularly difficult where the benefits/costs assessment is not clearly stated through an Order 1000 or Order 890 process that quantifies benefits in accordance with a Commission-approved methodology.[314] The NOI's difficult-to-quantify potential objectives will require case-by-case fact- and assumption-driven determinations, and potentially evidentiary hearings. Automatic benefits-based incentives would not meet Section 219 requirements. Characteristics-based incentives would be completely arbitrary. *See* response to Q 12.

3. Interaction Between Different Potential Incentives in Determining Correct Level of ROE Incentives (Q 93-95)

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?

A formulaic approach is inappropriate for determining the level and combination of incentives. It will not ensure the total package of incentives is tailored to the project's risks, taking into account risk-reducing incentives and measures (which include offering joint ownership), consistent with the 2012 Policy Statement. Case-by-case review is even more critical to benefits-based incentives. *See* response to Q 90-92.

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?

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[313] *See* response to Q 7.

[314] *See* response to Q 5 subpart g.

If the Commission retains the current risks and challenges framework, the 2012 Policy Statement provides guidance regarding the level and combination of incentives. If it adopts a benefits-based approach, much more detail will be required as to its methodology for analyzing (and quantifying) benefits, the appropriate level and combination of incentives, and why the total package is just and reasonable. *See* response to Q 5. The difficulties of doing so argue for retaining the current approach.

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?

A limit on total incentives is needed. First, Section 219 allows for ROE incentives sufficient to "attract[] new investment in transmission facilities (including related transmission technologies)" but "subject to the requirements of [Sections 205 and 206] that all rates . . . be just and reasonable and not unduly discriminatory or preferential."[315] Any incentive rate boost must be "in fact needed, and . . . no more than is needed, for the purpose."[316] The Commission must ensure that a utility's total ROE, including all incentives, is no higher than necessary to attract new investment. Under the Commission's current policy, a utility may be granted multiple ROE incentives—for joining an RTO, for being an independent Transco, and for project-specific risks and challenges. Even though individual ROE incentives could be considered just and reasonable in isolation, the total package may be unjust and unreasonable. For example, an independent Transco in an RTO developing a transmission project using advanced technology might seek multiple ROE incentives that collectively add some 300 basis

[315] 16 U.S.C. §§ 824s(b)(2), 824s(d).

[316] *City of Detroit*, 230 F.2d at 817. *See also* Order 679-A PP 25, 21 (incentives are awarded only where they "materially affect" decisions and are "tailored to address the demonstrable risks and challenges").

points. Such a massive addition to the base ROE (which itself should be sufficient to attract capital) would—on its face—exceed the rate needed to attract new investment.

Second, a cap on incentives provides useful assurance to state and local siting and permitting authorities, their constituents, and ratepayers generally, that the checks they will have to sign to pay for new transmission lines are not blank, i.e., will not be entirely untethered from costs. While the Commission may, in individual cases, choose to limit the total package of ROE adders allowed, an explicit outer-bound limit for all cases provides a needed signal to those outside the Commission whose support for transmission development is essential to its realization. The Commission should take to heart the signal that Entergy Corp.-area state regulators sent when they rejected ITC's acquisition of Entergy Corp.'s transmission facilities on the ground that federally-determined transmission rates would be excessive.[317]

While a cap on summed ROE adders is needed, the cap should not be tied to the top of the range of proxy results.[318] Relying on a proxy group range (rather than its distribution) for any purpose[319] is statistically unsound and produces unpredictable results. Using the top of the range of proxy results as the maximum total ROE focuses the incentive inquiry on a single proxy company that happens to produce the highest result, discarding relevant information about the distribution of the other proxy

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

[318] *See* Joint Association Comments filed today by TAPS and others in Docket No. PL19-4, § III.A.1.

[319] The Commission has used or proposed to use range-based measures for a variety for purposes: the midpoint for setting base ROEs for utilities in RTOs; the 5/8th mark for a level below which a rate will not be found unjust and unreasonable; and (as relevant in this response) the top of the range to set a cap on total ROE.

companies. The Commission has recognized the risk that an atypically high proxy company at the top of the range could skew results.[320] Because the ROE result for the single proxy company at the top of the range can vary widely from case to case, can be skewed by data errors,[321] and can change significantly based on the precise timing of a filing,[322] neither utilities nor consumers would be able to reliably predict the level at which incentives will be capped. Not only does this reduce regulatory certainty, but it invites additional litigation over whether a company at the top of the range should be included or excluded from the proxy group.

Instead, the Commission should establish a fixed cap on total ROE incentives. It should cap all company-wide ROE incentives at 50 basis points and all project-specific incentives at 100 basis points, allowing a maximum cumulative adder of 150 basis points for any one rate base component. The cap would rarely bind, especially once RTO Adders sunset as TAPS recommends. But it would avoid a misplaced focus on proxy group outliers, improving interjurisdictional comity and regulatory certainty.

4. Bounds on ROE Incentives (Q 96-97)

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

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?

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

[321] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030, P 47 n.102 (2018).

[322] *See, e.g.*, Prepared Cross-Answering Testimony and Exhibits of Ellen Lapson, CFA, on Behalf of the New England Transmission Owners, Ex. No. NET-1602 at 1, 11, *ENE (Env't Ne.) v. Bangor-Hydro Elec. Co.*, Docket No. EL13-33 (Apr. 21, 2015), eLibrary No. 20150421-5260 (Wolfe Research report stating that, with a range-based approach to determining the zone of reasonableness, "timing of the data is key" and "the DCF input timing is 'everything'").

The Commission should retain its discretion to determine the appropriate level of ROE incentives (below the cap, *see* response to Q 95) rather than establish pre-determined levels for incentive ROEs. Particularly as new technologies emerge, the Commission should not give up its ability to individually evaluate each project and its context,[323] which should continue to include risks and challenges.[324] And it should not put a lower bound on its discretion to allow only a very limited (or no) ROE incentive given the circumstances, including whether applicant has taken risk reducing measures and the other incentives requested. Given the effectiveness of risk-reducing incentives and their impact on the appropriateness of ROE incentives, ROE incentives should continue to be granted only in limited circumstances where justified, consistent with the Commission's implementation of the 2012 Policy Statement.

A discussed in response to Q 95, when the Commission grants project-specific ROE incentives, they should be subject to an outer-bound cap. The Commission should require that the sum of all project-specific incentives not exceed 100 basis points, and cap all company-wide ROE incentives, while they apply, at an additional 50 basis points.[325]

E. *Metrics for Evaluating the Effectiveness of Incentives (Q 98-105)*

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?

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

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

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[323] *See* responses to Q 5, 7-8.

[324] *See* response to Q 1-2.

[325] For example, if a utility were to demonstrate eligibility for a 50 basis point RTO incentive, a 25 basis point independent Transco incentive, and a 100 basis point project-specific adder, its combined ROE incentives would be capped at 150 basis points. If the RTO incentive were to expire before the Transco incentive expired, the utility would continue to receive the 25 basis point adder until the expiration of the Transco incentive. *See* response to Q 83-84 (duration of RTO and Transco incentives).

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

Evaluation of any benefits-based incentive system must assess both: (1) whether individual projects that have been granted incentives actually deliver the net benefits claimed when the incentive was granted;[326] and (2) whether actual benefits to consumers are greater overall when projects are granted incentives based on claimed benefits versus the existing risk-and-challenges framework. As to the first question, project-specific data are needed, but Form FERC-730 is inadequate. Particularly if incentives are granted based on claimed project benefits, more detailed data will be necessary, including: (1) benefits and costs projected at the time the incentive is granted (including the costs of the incentive); (2) project status; and (3) actual benefits and costs (including the costs of the incentive) (*see* response to Q 87-89).

The second question—whether actual benefits to consumers are greater overall when the Commission awards incentives based on claimed benefits, versus the current risk-and-challenges framework—will be harder to study. As the NOI recognizes (P 48), it is difficult to identify the extent to which a particular incentive motivates a developer to

[326] As discussed in response to Q 12, an incentives program that assumes benefits and assigns incentives based on project characteristics would clearly be arbitrary and contrary to the FPA. TAPS' response to these metrics questions therefore assumes that any benefits-based incentive system would require the incentive applicant to document and provide evidence of specific project benefits.

take a particular action. At minimum, however, to determine whether incentives have been effective the Commission will need to compare projects that *have not* received incentives to those that *have*; and thus collect information for both.

Simply expanding the sample to include non-incentive projects will not necessarily yield adequate information to evaluate the effectiveness of any incentives system. For example, in many regions, the bulk of transmission projects are reliability projects. Although these projects may also provide substantial economic or public policy benefits, there may be no information on the magnitude of those benefits from the applicable planning processes that can be used to make comparisons. Regional statistics on energy price, delivered price, and price differentials can help partially fill this gap, but cannot capture important nuances. Structured case studies, complemented by descriptive statistics and statistical analysis, may be the most effective way to determine if any new incentives system incents voluntary transmission development that benefits consumers. Study design and the data that will need to be collected will depend on whether and how the Commission modifies its existing policies.

CONCLUSION

The Commission should take into account TAPS comments in considering whether and how to revise its transmission incentives policies.

Respectfully submitted,

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