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 ITC HOLDINGS CORP.

Pursuant to the March 21, 2019 Notice of Inquiry ("NOI") issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in the above-captioned docket,[1] ITC Holdings Corp. on behalf of its operating subsidiaries International Transmission Company d/b/a ITC*Transmission* ("ITCT"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains") (collectively, "ITC") respectfully submits these comments on the Commission's electric transmission incentives policy adopted pursuant to section 219 of the Federal Power Act ("FPA").[2]

I. INTRODUCTION

Commission policy should support and appropriately incentivize transmission investments that enhance the reliability and resilience of the bulk-power system. As an independent transmission company, ITC is solely focused on building the "greater grid" by modernizing the existing transmission system, enhancing its security and reliability, and ensuring that it provides value to customers.

Today's electric transmission grid is undergoing a fundamental transformation driven by market forces, state policies, consumer demand, existing and emerging threats, commitments to environmental sustainability, and a large-scale transition to lower-carbon

[1] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, 166 FERC ¶ 61,208 (2019).

[2] 16 U.S.C. § 824s.

gas and zero-emission renewable generation. Distributed generation, demand-side management, electric battery storage, and electric vehicles are also driving significant changes in how the grid is planned, developed, and operated. In an economy that is increasingly reliant on the strength and efficiency of our bulk-power system, our nation's transmission policies must support economic growth and sustainability. To that end, the Commission must ensure appropriate polices are in place to identify, fund, and build transmission solutions that connect consumers to emerging generation sources and help reduce the overall delivered cost of energy.

ITC supports and endorses the Commission's efforts to review and strengthen its incentives policy, and appreciates the recent statements made by individual Commissioners acknowledging the role that transmission incentives will play in developing the transmission grid of the future. ITC believes there is an emerging consensus regarding the necessary attributes of a modernized transmission grid and this consensus offers a productive starting point for the Commission's deliberations.

Reliability and resiliency should remain of paramount concern to the utility industry. At the same time, the transmission grid must facilitate efficient markets and delivery of low-cost renewable power to consumers. Customers are demanding it and, in turn, utilities are committing to it at a rapid pace. The future grid must facilitate this transition as quickly as possible and offer customers access to the lowest cost resources, including those located far from load.

With these goals in mind, FERC's incentives policy must ensure that capital is appropriately attracted towards grid investments. As it reviews its incentives policy, FERC should not devalue existing incentives like the Transco and Regional Transmission

Organization ("RTO") adders that have a demonstrated record of providing tangible benefits to customers. At the same time, there are opportunities for new incentives which can help direct investment towards projects that provide even greater value to customers in the form of enhanced reliability and resilience, increased innovation, or joint utility planning. The NOI also provides the Commission with an opportunity to consider "non-traditional" incentives to achieve certain outcomes.

The Commission's transmission incentives policy, however, is just one aspect of a broader set of policies that must be aligned to drive investment in the grid of the future. While a reasoned return on equity ("ROE") policy and sufficient incentives create opportunities to deploy capital, those investments can only be made after they have been identified and approved in regional planning processes. As a consequence, the availability of outcome-specific financial incentives may have little-to-no impact on whether a specific grid investment is pursued if the planning process is itself prohibitive. The Commission, therefore, should also reexamine whether its regional and interregional planning and cost allocation policies are impeding needed investment and whether those policies, like the incentives policy, should be revised to ensure that Commission policy is facilitating the grid of the future that customers demand.

II. EXECUTIVE SUMMARY

Section 219 of the FPA directs the Commission to adopt an incentives policy that "appropriately encourages the development of the infrastructure needed to ensure grid reliability and reduce congestion to reduce the cost of power for consumers."[3] The

[3] FERC News Release, FERC Opens Inquiry on Improvements to Electric Transmission Incentives Policy (Mar. 21, 2019).

Commission's transmission incentives have played – and will continue to play – a critical role in facilitating needed investment in transmission infrastructure. As the largest independent transmission provider in the United States, ITC supports the Commission's review of its incentives policy and its desire to create a more reliable and resilient grid that provides tangible benefits to consumers. To achieve this shared objective, ITC recommends that the Commission's incentives policy incorporate the following elements.

A. <u>ROE Incentives</u>

1. <u>Retention of the Transco Adder</u>

The Commission has long recognized that transmission-only companies ("Transcos") provide substantial benefits to consumers because of their singular focus on transmission development and operations, and their ability to make significant capital investments in both existing and new transmission infrastructure.[4] Transcos also respond more rapidly and precisely to market signals indicating the need for new transmission investment,[5] and have achieved industry-leading performance levels through enhanced asset management and the creation of operational efficiencies.

Accounting for these attributes, the Commission included a Transco ROE incentive in Order No. 679 based "on the proven and encouraging track record of Transco investment in transmission infrastructure," as well as the "encouraging" expansion plans of the Transcos that had received incentive rate treatment to date.[6] According to the Commission, "no other business structure has a transmission investment record similar to that of a

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[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, at P 224 ("Order No. 679"), *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006) ("Order No. 679-A"), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[5] *Id.*

[6] *Id.* at PP 222-23.

Transco . . . ."[7] The Commission determined that "this positive record of Transco investment in transmission facilities is related to the stand-alone nature of these entities."[8]

Transcos continue to facilitate a robust and reliable transmission grid that facilitates competitive markets; the passage of time since the issuance of Order No. 679 has in no way diminished the unique and unparalleled benefits that Transcos deliver to consumers. The Commission should not, therefore, reduce the Transco adder or limit its availability by either awarding it on a project-by-project basis or requiring Transcos to provide additional justification for the Transco business model.

In fact, looking at the historical capital investments made by Transcos and the reliability record of Transco-owned assets, the benefits to consumers are self-evident. For example, since its inception, ITC has invested more than $8 billion to improve the grid. These transmission investments have benefitted consumers by reducing congestion, increasing reliability, and providing access to remotely located renewable energy resources. Further, Transcos like ITC are able to look at the transmission system broadly to evaluate the most efficient long-term solutions for regional system needs. This business model allows Transcos to look both inside and outside of their own footprint for solutions that will benefit customers now and in the future and this perspective plays a vital role in defining the projects that are proposed in RTO planning processes.

The Transco adder also recognizes other planning benefits related to the facilitation of generator interconnections. Transcos ensure open access and non-discriminatory treatment of generation resources in part because Transcos do not own generation that may

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[7] *Id.* at P 225.

[8] *Id.* at P 224.

be affected by the interconnection of new generation resources. Independence from all electricity generators, buyers, and sellers allows planning improvements to the electric transmission grid for the broadest public benefit. In short, Transcos can do what most other utility providers cannot: put their sole focus on building the greater grid required for, and necessitated by, today's consumers.

Investment decisions made by Transcos and private investment in Transcos are not, however, made in a vacuum; these decisions are significantly informed by the Commission's incentives policy. If the Commission restricts or otherwise reduces the Transco adder, the ability of Transcos to efficiently and effectively make capital investment in transmission infrastructure will be at risk. There is no compelling policy reason or change in circumstances that warrants a devaluation of the reliability and consumer benefits that Transcos continue to provide.

ITC does recommend, however, that the Commission revise its current policy regarding the scope of the adder for Transcos that have affiliations with market participants outside of the RTOs or Independent System Operators ("ISO") in which they operate. Specifically, the Commission should clarify that it will not reduce a Transco adder for reasons related to independence unless a Transco is operating within the *same* RTO or ISO as its affiliated market participants. This policy would better reflect the regional contributions of Transcos, better align with the standard of independence set forth in Order

No. 2000[9] and the Commission's regulations,[10] and resolve the uncertainty that has been created by recent Commission precedent.[11]

2. Retention of the RTO Adder

As detailed at length in the comments of the Edison Electric Institute ("EEI") and the MISO Transmission Owners, rate incentive treatment should be granted to transmitting or electric utilities that participate in a RTO as required by section 219(c) of the FPA.[12] As the Commission, market participants, consumers, academics, and utilities have uniformly acknowledged, RTOs provide significant benefits. These benefits include more efficient markets, more effective transmission planning, increased reliability, and coordinated operations on a regional and multi-regional basis. All of these attributes significantly reduce costs to consumers and provide a level of reliability that could not be achieved otherwise. Therefore, the Commission should maintain its 50 basis point adder for RTO participation and reject any arguments that the RTO adder should be available only for a fixed period of time or awarded on a project-specific basis. The benefits for consumers of RTO participation are continuous and not project-specific; therefore, the RTO adder for transmitting and electric utilities should neither sunset nor be limited to specific projects.

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[9] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. and Regs. ¶ 31,089 (1999) ("Order No. 2000"), *order on reh'g*, Order No. 2000-A, FERC Stats. and Regs. ¶ 31,092 (2000) ("Order No. 2000-A"), *aff'd sub nom. Public Utility District No. 1 Snohomish County Washington, et al. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[10] 18 C.F.R. § 35.34(b)(2).

[11] *See e.g., Consumers Energy Co. et al. v. International Transmission Co. et al.*, 165 FERC ¶ 61,021 (2018); *NextEra Energy Transmission New York, Inc.*, 162 FERC ¶ 61,196 (2018).

[12] 16 U.S.C. § 824s(c).

3. Sliding Scale Incentives Based on Benefits and Characteristics

To incent projects that have the greatest value to consumers, Commission policy should adopt a sliding scale approach to incentivizing capital investment in transmission infrastructure. This would encourage transmitting utilities to plan, propose, and develop infrastructure that maximizes consumer value by providing multiple value streams. Specifically, the Commission could evaluate projects based on an expected benefits and project characteristic basis. Projects eligible for incentives would include, among others: transmission facilities that are expected to reduce congestion; projects that increase reliability or resilience beyond North American Electric Reliability Corporation ("NERC") requirements; interregional projects; transmission facilities that provide greater market access for generation, future incremental transmission, or otherwise unlock constrained resources; projects that allow for greater operational flexibility; and transmission projects in regions with persistent needs.

The ROE adder for these types of projects would range from 50 to 100 basis points, with projects that provide multiple value streams eligible for the maximum incentive. Proponents for the ROE adder would have the opportunity to provide qualitative and quantitative analyses to support the incentive request, but the Commission should not adopt a bright-line test or require the adoption of a benefit-to-cost ratio threshold. Additionally, projects approved through an RTO planning process and deemed to provide multiple value streams (*e.g.*, Multi-Value Projects in the Midcontinent Independent System Operator, Inc. ("MISO") region) should automatically be entitled to the maximum ROE adder of 100 basis points (subject to a section 205 filing).

4. Prospective Annual Adders for Operational Excellence

To promote operational excellence, the Commission should adopt an incentive that rewards transmitting utilities that operate "best-in-class." Based on an objective standard administered by the Commission (*i.e.*, outage data or data generated from the NERC Transmission Availability Data System ("TADS")), utilities whose prior performance places them in the top quartile of transmitting utilities should receive a 50 basis point ROE adder. Once granted, the adder would be incorporated into a utility's prior year true-up for utilities employing a formula rate. For example, if the Commission conducted an analysis in 2020 and determined that a utility merited an operational excellence adder, the utility could incorporate the adder through its 2019 true-up. The adder would sunset when the Commission conducts a new performance review, which could be conducted periodically (*e.g.*, every five years). This incentive is consistent with section 219, which specifically references performance-based rate treatment, and benefits consumers by incenting and rewarding operational excellence that exceeds the baseline requirements set by NERC.

5. System-Wide Incentives for Implementation of Resilience Plans

Since the adoption of Order Nos. 679 and 679-A, there has been an increasing focus on the resilience of domestic energy infrastructure and the electric transmission grid in particular. This focus is not misplaced. The intensity and frequency of emerging threats, both natural and manmade, justify immediate action. Deploying capital now to make the grid more resilient will benefit consumers over the long-term by mitigating the adverse impacts and duration of disruptive events.

Accordingly, the Commission's incentives policy should incorporate a program that incents utilities to proactively and aggressively address these resilience threats.

Specifically, the Commission should adopt a policy that permits a utility to seek an ROE incentive if it establishes a utility-specific, Commission-approved Resilience and Security Action Plan ("RSAP"). Measures in the RSAP could include capital projects, ongoing operation and maintenance activities, and participation in collaborative programs. In its filing seeking incentive rate treatment, a utility would provide a detailed rationale as to how its proposed actions would improve its system's security or resilience. The RSAP adder would be applied in the same manner as the RTO adder (*i.e.*, a system-wide adder), and the magnitude of the adder would be scaled based on the scope of the RSAP.

6. Incentives for New Technologies

The Commission also should consider granting incentives for projects that involve implementing new technologies to provide quantifiable congestion reduction, resilience, reliability, or other benefits. Such incentives would foster innovative improvements in resilience, transfer capability, and other challenges facing the grid. Examples of such innovations could include improved conductors, new designs, digital control, and monitoring applications, as well as other hardware, software and associated protocols. Such incentives would represent a small cost to ratepayers but could provide significant reliability, economic, and resilience benefits to the grid and customers.

B. Non-ROE Incentives

1. ROFR for Jointly-Planned Interregional Projects

Although Order No. 1000 requires coordination among neighboring transmission planning regions, it has not fulfilled its promise as a policy intended to facilitate the development and construction of interregional transmission facilities. The lack of new investment in interregional transmission facilities has not served consumer interests and has left unaddressed the myriad of issues created or exacerbated by seams. These issues include barriers to competition, adverse impacts to reliability, and constraints that unnecessarily limit the ability of the transmission grid to timely and efficiently respond to, and recover from, disruptive events. The Commission could facilitate the development of interregional projects if it adopted a limited right-of-first-refusal ("ROFR") for jointly-planned interregional projects developed and proposed by adjacent utilities located in different regions. While ITC acknowledges that this proposal would require a modification of the Commission's current policy, ITC believes the lack of interregional projects justifies a limited ROFR to promote the development of interregional facilities which has effectively been stalled in recent years.

2. Capitalization of Certain Expenses

There are a number of activities and initiatives undertaken by transmitting utilities that directly support a more reliable and resilient transmission grid, the benefits of which accrue directly to consumers both in the short-term and the long-term. These activities include investments in research and development, vegetation management, cloud-based computing, and cyber and physical security enhancements. Under current Commission policy these investments are recovered as expenses. To incent transmitting utilities to make investments to enhance the stability and the security of the grid, the Commission should capitalize these costs and allow utilities to earn a return on these investments.

3. Retention of CWIP and Abandonment Incentives

As explained more fully below and in the comments of EEI, the Commission should continue to mitigate the financial and regulatory risks associated with transmission investment by allowing for inclusion of 100 percent of Construction Work in Progress

("CWIP") in rate base and recovery of 100 percent of prudently incurred pre-commercial costs as an expense or regulatory asset. The Commission should also allow for recovery of 100 percent of prudently incurred costs for transmission facilities that are abandoned due to factors beyond the control of the utility. These risk-reducing incentives help remove a significant regulatory barrier to transmission investment: the potential lack of cost recovery.

The Commission's policy, however, should be updated to make these non-ROE incentives automatically available (subject to a section 205 filing) for projects that are approved through a regional planning process, as these incentives are ratemaking measures that reduce project uncertainties, financial burdens, and credit and cash flow risk for the utility and its customers. Further, the Commission should expand the abandoned plant incentive to allow the costs of unsuccessful Order No. 1000 proposals to be recovered through regulatory asset or deferred pre-commercial cost-recovery incentives. This would facilitate greater participation in, and development of, Order No. 1000 projects.

C. <u>Policy Issues</u>

1. <u>Total ROE Can Exceed the Zone of Reasonableness</u>

The Commission should revise its policy capping a utility's total ROE at the upper bound of the zone of reasonableness. Section 219 of the FPA was enacted by Congress to ensure that incentives are available to utilities to encourage capital investment in transmission facilities. These investments provide direct consumer benefits by ensuring reliability, enhancing the resiliency of the transmission grid, reducing congestion, facilitating state policy initiatives, and bringing new generation resources to market. These investments have enduring value for consumers that, over the long run (*i.e.*, over the life of a facility), will provide significantly greater benefits than any incremental costs associated with an ROE that may exceed the upper end of the zone of reasonableness.

These demonstrated benefits provide the Commission sufficient justification to find that a total ROE that exceeds a base ROE's zone of reasonableness because of incentive adders remains a just and reasonable rate. In contrast, by tying available incentives to the base ROE zone of reasonableness, Commission policy unnecessarily limits the potential consumer and reliability benefits that section 219 was intended to incent. Even if the Commission determines that some upper bound is necessary or warranted, incentive-driven ROEs should be able to exceed the base ROE's upper bound by some amount. For example, the Commission could adopt a policy that enables a transmitting utility's total ROE to exceed the base ROE's zone of reasonableness but cap the exceeded amount by 100 basis points.

2. <u>Abandon the "Risks and Challenges Standard"</u>

Section 219 does not mandate a "risk and challenges" framework for evaluating incentive applications and the framework is inconsistent with an incentives-based system because it relies, in part, on risks and challenges presented by third-parties (*e.g.*, potential permitting obstacles or public opposition). To better align with section 219 and the Commission's longstanding policy of offering incentives to induce future behavior, an incentives-based framework should, as discussed above, incent transmitting utilities to propose, invest in, and construct transmission facilities that have certain characteristics or anticipated benefits. Projects warranting incentives include projects that are expected to reduce congestion, promote resiliency, enhance reliability, and bring new generation resources to market. An expected benefits or project characteristic framework is a more useful tool to evaluate incentive requests because it does not rely on consideration of external factors.

3. Duration of Incentives

Both the investment community and the utility industry need regulatory certainty to inform decisions regarding long-term planning and the deployment of capital. In an industry where investments are expected to span decades, regulatory certainty is necessary to support sustained investment in the grid. As intended by Congress, incentives granted to transmitting utilities have been central to the development of a more robust transmission grid that has improved reliability, strengthened competitive markets, and enabled grid operators to better plan for and address disruptive events. The Commission's incentives policy has been successful in this regard because there is certainty that capital, once deployed for a project, will continue to receive incentive rate treatment over the life of the asset. This certainty has led to sustained investments in U.S. transmission infrastructure. Introducing the potential for sunsetting incentives, or reducing incentives over time due to changed circumstances, would inject a level of uncertainty into the utility planning process sufficient to undermine transmission investments. To the extent transmission investment is reduced because of this uncertainty, the impact of incentives would be diluted and would run counter to Congressional intent that transmission incentives be used to ensure reliability and reduce congestion. Commission policy, therefore, should not adopt any sunsetting of, or potential revision to, ROE incentives once granted.

D. Reassessment of Order No. 1000 Implementation

As noted above, achieving the objectives of section 219 – a more resilient and reliable grid that benefits consumers – cannot be achieved by incentives alone. Order No.

1000 directly affects the success of incentives because it governs how transmission facilities are proposed, planned, approved, and developed.

As the Commission acknowledges, interregional transmission facilities "have been scarce to date."[13] To be exact, there has not been a single interregional transmission project developed as a result of Order No. 1000. This is the case, in large measure, because in implementing Order No. 1000 most pairs of adjoining RTOs/ISOs subordinated the interregional planning process to the regional planning processes, requiring that a viable interregional project displace already-approved regional projects in each region and making it exceedingly difficult to obtain approval for any interregional project.

Without necessary reforms, these projects are unlikely to be built because the transmission planning processes for interregional projects are unworkable. In order to advance and facilitate interregional projects, ITC believes that planning regions must be directed to holistically evaluate planning drivers and benefit metrics, which includes increasing the range of benefits considered—to the extent they are objectively quantifiable and not overlapping—and evaluating reliability, economic, public policy, and resilience drivers on an additive basis. Further, neighboring planning regions should be required to jointly develop a single set of criteria for approval and cost allocation of interregional projects rather than separate requirements resulting in "double" or "triple hurdles" for approval, which have a strong tendency to undermine otherwise highly-beneficial projects. Additionally, the Commission should continue to be receptive to one-off, targeted, interregional projects to which both RTOs agree, such as the recent MISO-PJM Targeted Market Efficiency Projects. Although not an adequate substitute for true regular

[13] NOI at P 30.

interregional planning, these approaches also have potential to enhance grid resilience, particularly by ameliorating historical congestion and improving energy deliverability. Finally, the Commission should direct planning regions to establish a timeline for conducting each step in the interregional planning process. These reforms will help build a greater grid that will be able to function as a true network that is strong, resilient, and sufficiently efficient to meet our energy needs now and for the future.

ITC encourages the Commission to issue a separate Notice of Inquiry to address potential improvements to regional and interregional transmission planning and approval processes. Without corresponding reforms, the effectiveness of the Commission's transmission incentives policy may be neutered; without upfront planning and approvals, transmission projects that may warrant incentives may never be realized. This process should begin without delay. As Chairman Chatterjee succinctly explained in a recent statement, "[e]veryone seems to agree that Order 1000 is not working . . . ."[14] Although there have undoubtedly been significant successes attributable to Order No. 1000, "the introduction of competitive transmission that it required has been slower and more difficult than anticipated and has arguably hurt transmission planning . . . ."[15] As such, ITC believes that the time has come to "roll up our sleeves and figure out how to more effectively bring

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[14] Herman K. Trabish, *With new transmission urgently needed, FERC Chair hints at a new Order 1000 proceeding*, UTILITY DIVE (May 31, 2019) (Quoting an emailed statement by Chairman Neil Chatterjee), available at https://www.utilitydive.com/news/with-new-transmission-urgently-needed-ferc-chair-hints-at-a-new-order-1000/555586/.

[15] *Oversight of FERC: Ensuring Its Actions Benefit Consumers and the Environment*: *Hearing Before the Subcomm. On Energy of the H. Comm. On Energy and Commerce* (June 12, 2019) (written testimony of Commissioner Cheryl A. LaFleur, at p. 6).

competition to bear in transmission development" in a way that "better deliver[s] on Order 1000's promise."[16]

III. LEGAL FRAMEWORK FOR THE NOI

FPA section 219 directs the Commission to establish, "by rule, incentive-based (including performance-based) rate treatments" for interstate transmission of electricity by public utilities "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[17] Section 219 provides specific requirements, requiring the rule to:

1. promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;
2. provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);
3. encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and
4. allow recovery of (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to the FPA; and (B) all prudently

[16] Chairman Neil Chatterjee, Address at S&P Global Platts 2018 Transmission Planning and Development Conference (June 21, 2018). *See also Oversight of FERC: Ensuring Its Actions Benefit Consumers and the Environment*: *Hearing Before the Subcomm. on Energy of the H. Comm. on Energy and Commerce* (June 12, 2019) (written testimony of Commissioner Bernard L. McNamee, at p. 3, noting that Order 1000 is among those "issues that are confronting the Commission and the electric energy" that are "important and deserves our attention as FERC Commissioners.").

[17] 16 U.S.C. § 824s(a).

incurred costs related to transmission infrastructure in national interest electric transmission corridor projects approved by the Commission.[18]

FPA section 219 also requires that the Commission "to the extent within its jurisdiction," provide incentives to utilities that join a RTO.[19]

IV. RESPONSE TO SPECIFIC COMMISSION INQUIRIES

A. Approach to Incentives Policy: Project Benefits and Project Characteristics

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?

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?

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

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

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?

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

Q 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 incentive?

Q 24) Should the Commission consider incentivizing transmission projects that are scaled to more efficiently facilitate interconnection of, or transmission to, additional generation?

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[18] *Id.* at § 824s(b)(1)-(4).

[19] *Id.* at § 824s(c).

What other measurable economic efficiency benefits should be considered a bright line metric for the purposes of economic efficiency?

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?

The Commission should abandon an incentive evaluation framework based on "risks and challenges" and award incentives based on a specific project's anticipated benefits and characteristics. ROE adders should be granted on a sliding scale with projects providing multiple benefits to consumers (*e.g.*, increased reliability, reduced congestion, enhanced resiliency, access to new generation) receiving a maximum adder of 100 basis points. Under this construct, project proponents would petition the Commission for incentive rate treatment by providing a qualitative and/or quantitative assessment of project benefits and characteristics.

Section 219 does not require that the Commission assess "risks and challenges" to evaluate incentive applications, and this metric is not an optimal mechanism for an incentive program because it addresses, in part, risks and challenges presented by third parties (*e.g.*, potential permitting obstacles or public opposition). To better align with section 219 and the Commission's longstanding policy to offer incentives to induce future behavior, a value-based framework should incent utility investment in projects that provide maximum utility for consumers. To achieve that objective, the evaluation of potential incentive rate treatment should focus on a project's characteristics and/or anticipated benefits.

To incent projects that have the greatest value to consumers, Commission policy should adopt a sliding scale approach to incentivizing capital investment in transmission infrastructure. This would encourage transmitting utilities to plan, propose, and develop infrastructure that maximizes consumer value by providing multiple value streams. Specifically, the Commission could evaluate projects based on an expected benefits and project characteristic basis. Projects eligible for incentives would include, among others, transmission facilities that are expected to reduce congestion, projects that increase reliability or resilience beyond NERC requirements, interregional projects, projects that mitigate the impact of disruptive events, projects that facilitate the implementation of state and national public policies, transmission facilities that provide greater market access for generation or otherwise unlock constrained resources, and transmission projects in regions with persistent needs.

The expected benefits/project characteristics ROE adder would range from 50 to 100 basis points, with projects providing multiple value streams eligible for the maximum incentive. Proponents for the ROE adder would have the opportunity to provide qualitative and quantitative analyses to support the incentive request, but the Commission should not adopt a bright-line test or require the adoption of a benefit-to-cost ratio threshold. Rather, the Commission should establish general principles articulating what a project proponent would need to demonstrate to be eligible for an adder and how the sliding scale would be applied. In implementing this policy, the Commission should clarify that projects would automatically be entitled to the maximum ROE adder of 100 basis points if they are: (1) approved through an RTO planning process; and (2) deemed to provide multiple value streams (*e.g.*, MISO Multi-Value Projects). Revising the incentives policy in this manner will encourage "multi-driver" or "multi-value" projects that offer multiple benefits from the general categories of projects described above, thereby maximizing benefits for consumers.

B. Incentive Objectives: Reliability, Security, and Resiliency

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

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

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

Q 32) Should the Commission incentivize physical and cybersecurity 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 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?

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?

The Commission's incentives policy should incorporate five distinct elements to improve grid security, improve reliability, and fortify the resiliency of the interstate transmission system.

First, as discussed above in Section III.A, "Approach to Incentives Policy", the Commission should adopt a sliding scale ROE adder for transmission projects that provide multiple benefits for consumers. Benefits that warrant ROE adders would include transmission projects that address reliability and resiliency issues beyond what is already required to comply with NERC reliability standards. Projects that fall into this category include, but are not limited to, protective asset replacements and rebuilds and other similar types of transmission investments.

Second, as more fully articulated in American Electric Power's comments, the Commission should incorporate a program that encourages utilities to go beyond minimum compliance with NERC Reliability Standards and proactively address resilience threats. Specifically, the Commission should establish an incentive that permits a utility to seek an ROE incentive if it establishes a utility-specific, Commission-approved RSAP. Measures in the RSAP could include capital projects, ongoing operation and maintenance activities, and participation in collaborative programs. Examples of such measures could include, among others, deployment of private communications networks, reduction or elimination of NERC critical substations, enhanced cyber security measures, increased Supervisory Control and Data Acquisition ("SCADA") utilization, investment in long-lead critical equipment to be shared with other utilities, enhanced blackstart capabilities, and the physical hardening of assets.

In its filing seeking incentive rate treatment, a utility would provide a detailed explanation of how its proposed actions would improve its system's security or resilience, including an assessment of the types of threats that are addressed by the RSAP and how the planned actions would enhance grid resilience. The Commission would assess the proposed RSAP and determine whether the RSAP supports the applicant's requested transmission rate incentive, informed by how the plan supports the Commission's resilience policies. If granted, the RSAP adder would be applied in the same manner as the RTO adder (*i.e.*, a system-wide adder), and the magnitude of the adder would be scaled based on the scope of the plan.

Third, the Commission should reclassify investments in research and development, vegetation management, cloud-based computing, and cyber and physical security enhancements such that they are capitalized and not expensed. All of these investments create a more reliable and resilient transmission grid that directly benefits consumers. Authorizing utilities to capitalize these activities would facilitate investments in projects that provide direct benefits to consumers in the form of a more reliable and secure grid.

Fourth, to incentivize operational excellence, the Commission should adopt an incentive that rewards transmitting utilities that operate "best-in-class." Based on an objective standard administered by the Commission (*i.e.*, outage data or data generated from the NERC TADS), utilities whose prior performance places them in the top quartile of transmitting utilities should receive a 50 basis point ROE adder. Once granted, the adder could be incorporated into a utility's prior year formula rate true-up. For example, if the Commission conducted an analysis in 2020 and determined that a utility merited an operational excellence adder, the utility could incorporate the adder by virtue of its 2019 true-up. This adder would be reviewed when the Commission conducts the next performance review of transmitting utilities, which could be conducted periodically (*e.g.*, every five years). This incentive is consistent with section 219, which specifically references performance-based rate treatment. Incentivizing utilities to strive for a level of operational excellence that surpasses the baseline requirements set by NERC and the performance levels of industry peers will provide quantifiable savings for customers as discussed further in Section IV.D.1 below.

Finally, as described more fully in the comments filed by WIRES, the Commission should consider granting specific, well-defined incentives for projects that involve implementing new technologies to provide quantifiable congestion reduction, resilience, reliability, or other benefits. Such incentives would foster innovative improvements in resilience or transfer capability or other measures that could grow exponentially to benefit grid operations over the coming decades. Examples of such innovations could include improved conductors, new designs, digital control, and monitoring applications, as well as other hardware, software and associated protocols. Such incentives would represent a small cost to ratepayers but could provide significant reliability, economic, and resilience benefits to the grid and customers.

C. Interregional Transmission Projects

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

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?

Despite the Commission's best efforts, implementation of Order No. 1000 has not resulted in the development of interregional transmission facilities. As the NOI notes, these facilities "have been scarce to date." The lack of development of interregional projects has left substantial consumer benefits unrealized, as seams issues continue to erect barriers to competition, threaten reliability, and unnecessarily constrain the ability of the transmission grid to timely respond to, and recover from, disruptive events.

To address the lack of interregional projects, the Commission should adopt a limited ROFR for jointly-planned interregional projects developed and proposed by adjacent utilities located in different regions. While this proposal requires a modification of current policy, ITC believes the lack of interregional projects justifies a limited ROFR to properly incent development of interregional facilities. Providing a limited ROFR will offer a non-ROE incentive to utilities to coordinate, share information, and conduct joint planning on a utility-to-utility basis, which will be more efficient than existing interregional coordination processes.

While ROE and non-ROE incentives will assist in the development of additional interregional projects, alone these incentives are not sufficient to fully address the lack of interregional projects and other planning and process barriers that impede transmission development. To comprehensively and holistically address transmission planning and approval issues, and to ensure that the transmission grid of the future meets the needs of consumers, the Commission should address potential improvements to transmission planning and approval processes through the issuance of a separate NOI. Without corresponding reforms to the transmission planning process, the desired outcomes that incentives are designed to achieve may never come to fruition.

D. Existing ROE-Adder Incentives

1. Transmission Only Companies

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

The Transco business model continues to provide substantial benefits to the grid and consumers, helps achieve the goals of section 219, and should be retained in its current form. In Order No. 679, the Commission executed on Congress' directives under section 219, creating several incentives for transmission infrastructure investment. Included in Order No. 679 was a Transco ROE incentive—an ROE adder available to stand-alone transmission companies that are approved by the Commission and sell transmission services at wholesale and/or on an unbundled retail basis, "regardless of whether it is affiliated with another public utility."[20]

The Commission has long recognized that the Transco model "is one of the most effective means of separating transmission interests from generation interests and achieving independence through a for-profit transmission company."[21] In turn, consumers benefit from the enhanced competition and reliability and new investment in infrastructure that the Transco incentive encourages.[22] Consumers also benefit from "lessened potential for discrimination, improved access to capital markets for transmission investment, improved asset management, and development of innovative services."[23] It is these benefits that led the Commission—invoking its authority under FPA section 205—to grant incentives for ownership and operation of transmission facilities by Transcos as early as 2003.[24]

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[20] Order No. 679 at P 201.

[21] *ITC Holdings Corp., et al.,* 102 FERC ¶ 61,182, P 1 ("*ITC Holdings*")*, reh'g denied,* 104 FERC ¶ 61,033 (2003).

[22] *Id.*

[23] *Michigan Electric Transmission Co., LLC,* 105 FERC ¶ 61,214, P 20 (2003).

[24] *Id.*

The Commission's inclusion of the Transco ROE incentive in Order No. 679 was based "on the proven and encouraging track record of Transco investment in transmission infrastructure," as well as the "encouraging" expansion plans of the Transcos that had received incentive rate treatment to date.[25] According to the Commission, "no other business structure has a transmission investment record similar to that of a Transco . . . ."[26] The Commission believed that "this positive record of Transco investment in transmission facilities is related to the stand-alone nature of these entities."[27]

The Transco ROE incentive adder was therefore critical to achieving section 219's goals of promoting reliable and economically efficient transmission of electricity "by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce" and "provid[ing] a return on equity that attracts new investment in transmission facilities."[28] Indeed, as the Commission noted in Order No. 679, the purpose of the Transco adder was to "build much needed transmission infrastructure" by approving an incentive "that both encourages Transco formation and is sufficient to attract investment after the Transco is formed."[29]

The Transco business model continues to deliver benefits to consumers and the Commission should not, in any way, limit the availability of the Transco adder by either awarding it on a project-by-project basis or requiring Transcos to provide additional

[25] Order No. 679 at P 222-23.

[26] *Id.* at P 225.

[27] *Id.* at P 224.

[28] 16 U.S.C. § 824s(b)(1)-(2).

[29] Order No. 679 at PP 221, 231.

justification regarding the benefits of Transcos. Because Transcos such as ITC are singularly focused on developing, owning, and operating transmission, they bring to bear substantial experience and an exceptional focus on operational excellence. For example, ITC has significantly improved the performance of the three transmission systems it acquired from third parties, with ITCT, METC, and ITC Midwest reducing the average number of outages on these systems by 48%, 24%, and 60%, respectively, since acquisition. These improvements in reliability stem from ITC's system investments over the years, as well as its targeted capital and maintenance programs. According to the North American Transmission Forum annual benchmark survey, ITC's transmission systems now perform in the top quartile for both the number of sustained outages per circuit and average circuit outage duration.

Independence from all electricity generators, buyers, and sellers also means that Transcos have no incentive to stall the generator interconnection process. Increasing system availability to new generation regardless of type will be of crucial importance as regions struggle to quickly and efficiently connect new generation projects in interconnection queues that "have expanded considerably" over recent years.[30]

Transcos also continue to invest in transmission at a much higher rate than their non-Transco counterparts that own transmission but have other capital-intensive businesses such as generation and distribution competing for capital. Since inception, ITC has invested more than $8 billion in improving the grid. These transmission investments have benefitted consumers by reducing congestion and increasing reliability. For example, an independent study of ITC's investments from 2008 to 2014 by ICF International ("ICF")

[30] NOI at P 31.

concluded that ITC's investments had quantifiable, positive financial impacts on reliability, renewable energy integration, and market efficiency. One example of reliability benefits that ICF quantified was ITC's upgrade of one component of its transmission system in Iowa. ICF determined that these upgrades and the resulting reduction in outages saved Iowa customers $98 million between 2008 and 2014 alone. ICF also found that ITC's recently constructed transmission projects in the Midwest saved ITC's customers and neighboring customers $714 million between 2010 and 2015 alone in reduced energy production costs due to decreased system congestion. ITC's transmission investments also have provided access to remotely located renewable energy resources, helping to satisfy consumer demand for access to renewable energy in the most economically efficient way possible. Indeed, the same ICF study found that ITC's transmission upgrades and interconnection policies allowed for the optimal siting of renewable resources and that, absent these upgrades, the wind resources ITC interconnected over the studied period would have had to site in less optimal locations where transmission capacity already existed, which would lead to slightly less energy per turbine. As a result, customers saved $587 million by avoiding the need for developers to increase capital costs (*i.e.*, by adding additional wind turbines) to achieve the same energy output from the wind farms over the study period.

These investments have been supported by the Transco ROE incentives granted to ITC by the Commission. Looking at the historical capital investments made by Transcos, and the reliability record of Transco-owned assets, the benefits to consumers are self-evident. If the Commission restricts or otherwise reduces the Transco adder then the ability of Transcos to efficiently and effectively make capital investments in transmission infrastructure will be at risk. There is no compelling policy reason or change in circumstances that warrants a devaluation of the reliability and consumer benefits that Transcos continue to provide. This applies to new assets as well as assets that a Transco acquires and improves either through additional capital investment or operational improvements.

ITC does recommend, however, that the Commission revise its current policy regarding the scope of the adder for Transcos that have affiliations with market participants outside of the RTOs or ISOs in which they operate. Specifically, the Commission should clarify that it will not reduce a Transco adder for reasons related to independence unless a Transco is operating within the *same* RTO or ISO as its affiliated market participants. This policy would better reflect the regional contributions of Transcos, better align with the standard of independence set forth in Order No. 2000[31] and the Commission's regulations,[32] and resolve the uncertainty that has been created by recent Commission precedent.[33]

Critically, the evaluation of whether a Transco is sufficiently independent to merit an incentive should adhere to the applicable legal standard for independence derived from the Commission's regulations: independence from market participants *in the relevant RTO*. This properly reflects that FERC's analysis should be tied to independence in the relevant

[31] Order No. 2000, *order on reh'g*, Order No. 2000-A, *aff'd sub nom. Public Utility District No. 1 Snohomish County Washington, et al. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[32] 18 C.F.R. § 35.34(b)(2).

[33] *See e.g.*, *Consumers Energy Co. et al. v. International Transmission Co. et al.*, 165 FERC ¶ 61,021 (2018); *NextEra Energy Transmission New York, Inc.*, 162 FERC ¶ 61,196 (2018).

market, not arbitrary physical boundaries that imply a fully integrated market where none exists.

As the Commission has previously explained in applying Order No. 2000's[34] independence principle to transmission companies, and as reflected in 18 C.F.R. § 35.34(b)(2):

> [T]he Commission considers the effect of ownership interests on the independent transmission company's independence, *i.e.*, whether Applicants' proposed ownership structure involves "market participants." In Order No. 2000, as amended by Order No. 2000-A , the Commission defined a market participant as: (i) any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary [services] to the RTO, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions; and (ii) any other entity that the Commission finds has economic or commercial interests that could be significantly affected by the RTO's actions or decisions. Under Order No. 2000, a market participant can have active ownership interests in an RTO of up to five percent for a transition period not to exceed five years, and can hold passive ownership interests in an RTO, subject to review by the Commission on a case-by-case basis. [35]

The above definition of "market participant" appears in Subpart F of Part 35 of the regulations, which specifies "Procedures and Requirements Regarding Regional Transmission Organizations." Expanding the review of independence beyond the RTO level—for example, to an interconnection-wide analysis—would read the words "the Regional Transmission Organization" out of the definition found in 18 C.F.R. § 35.34(b)(2). This would be inconsistent with the purpose and structure of the regulations in Subpart F, which prescribe the minimum requirements and functions of RTOs, including market-

[34] Order No. 2000, *order on reh'g*, Order No. 2000-A, *aff'd sub nom. Public Utility District No. 1 Snohomish County Washington*, *et al. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[35] *ITC Holdings* at P 27 (internal citations omitted).

related functions and independence requirements. The identification of market participants cannot be divorced from the RTO that operates the market.

The rulemaking that produced the definition of "market participant" provides further support for an RTO-specific independence analysis rather than an interconnection-wide review. The first characteristic for an RTO described in the Notice of Proposed Rulemaking ("NOPR")[36] that led to Order No. 2000 is independence from participants ***in the RTO's*** power markets. To achieve independence, the Commission proposed that "the RTO, its non-stakeholder governing board members and its employees must have no financial interests in market participants."[37] The text of the definition of market participant proposed in the NOPR[38] was:

> Market participant means any entity that buys or sells electric energy in the Regional Transmission Organization's region or in any neighboring region that might be affected by the Regional Transmission Organization's actions, or any affiliate of such an entity.

After receiving comments, the Commission found that the NOPR definition was too broad: "a literal reading of this definition would make market participants of every residential, commercial, industrial and wholesale electric customer in the RTO region and some neighboring regions. This is clearly too encompassing and was not our intent."[39] Order No. 2000 therefore narrowed the definition. As relevant here, the Commission dropped the reference to entities that buy or sell electric energy "in the Regional

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[36] Regional Transmission Organizations, Notice of Proposed Rulemaking, Docket No. RM99-2-000, May 13, 1999, 64 Fed. Reg. 31,390 (Jun. 10, 1999).

[37] *Id.* at 31,414. The NOPR explained in a footnote that "we use the terms 'stakeholder' and 'market participant' interchangeably. They mean any entity that buys or sells electric energy in the RTO's region or in any [neighboring] region that might be affected by the RTO's actions, or any affiliate of such entity." 64 Fed. Reg. 31,414, n.187.

[38] *Id.* at 31,437.

[39] Order No. 2000, FERC Stats. and Regs. ¶ 31,089, p. 31,062.

Transmission Organization's region or in any neighboring region that might also be affected by the RTO's actions." But while dropping the references to "regions" and "neighboring regions," the Commission maintained the linkage between status as a market participant and a specific RTO by revising the definition to apply to "any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides transmission or ancillary services to the Regional Transmission Organization . . . ."[40]

The Commission should use this proceeding to clarify that Transcos remain eligible for the maximum Transco adder as long as they do not have affiliated market participants operating *within the same RTO or ISO*. This policy clarification will bring the incentives policy into alignment with the Commission's prior determinations and current regulations and promote both the quality and level of investment Congress intended through section 219.

2. <u>RTO/ISO Participation</u>

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

The Commission should retain the ROE incentive for RTO participation in its current form, as mandated by section 219, for the reasons set forth in the comments filed on this issue by the MISO Transmission Owners, WIRES, and EEI. As noted in EEI's comments, the plain language of section 219 makes clear that the Commission "shall" provide incentives to each utility that joins a Commission-approved RTO.

The Commission has historically granted ROE-based incentives for utilities that join an RTO or ISO "in recognition of the benefits such organizations bring to

[40] Order No. 2000-A dropped the reference to the provision of transmission services by a market participant. Order 2000-A, FERC Stats. and Regs. ¶ 31,092, p. 31,361.

customers . . . ."[41] As the Commission has explained, "[t]he consumer benefits, including reliability and cost benefits, provided by [RTOs and ISOs] are well documented" and include:

> increased efficiency through regional transmission pricing and the elimination of rate pancaking; improved congestion management; more accurate estimates of [Available Transmission Capability]; more effective management of parallel path flows; more efficient planning for transmission and generation investments; increased coordination among state regulatory agencies; reduced transaction costs; facilitation of the success of state retail access programs; facilitation of the development of environmentally preferred generation in states with retail access programs; improved grid reliability; and fewer opportunities for discriminatory transmission practices.[42]

According to the Commission, "the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of [RTOs and ISOs] and is effective for the entire duration of a utility's membership in the [RTO or ISO]."[43]

It is incontrovertible that RTOs continue to generate significant benefits to consumers as a consequence of more efficient markets, more effective transmission planning, increased reliability, and coordinated regional operations. These benefits provide significant cost savings and a level of reliability that would not be achieved in the absence of RTOs. The Commission, therefore, should maintain its 50 basis point adder for RTO participation—which should be provided to every utility that participates in an RTO for the duration of the utility's membership in the RTO—and reject any arguments that the

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[41] Order No. 679 at P 312.

[42] Order No. 679-A at P 86 and n.141 (quoting Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,024.).

[43] *Id.* at P 86.

RTO adder should be available only for a fixed period of time or awarded on a project-specific basis.

3. Non-ROE Incentives

a. Retention of CWIP and Abandonment Incentives

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?

In Order No. 679, the Commission granted public utilities the ability to include 100 percent of CWIP in rate base and recover 100 percent of prudently incurred pre-commercial costs as an expense or regulatory asset.[44] The Commission granted these rate treatments because it recognized that they would "further the goals of section 219 by providing up-front regulatory certainty, rate stability and improved cash flow for applicants thereby easing the pressures on their finances caused by transmission development programs."[45] Similarly, to encourage transmission development by reducing the risk of non-recovery of costs, the Commission granted utilities the right to request to include 100 percent of prudently-incurred costs associated with abandoned transmission projects in transmission rates if such abandonment is outside the control of management.[46] As discussed in the comments filed by the MISO Transmission Owners, WIRES, and EEI, the Commission should continue to mitigate the financial and regulatory risks associated with transmission investment by retaining these incentives.

[44] Order No. 679 at P 115.

[45] *Id.*

[46] *Id.* at P 163.

As the Commission correctly recognized in Order No. 679, allowing utilities to include 100 percent of CWIP in rate base and recover 100 percent of prudently incurred pre-commercial costs as an expense or regulatory asset "removes a disincentive to construction of transmission, which can involve very long lead times and considerable risk to the utility that the project may not go forward."[47] Similarly, providing assurance of recovery of abandoned plant costs, while technically an "incentive" under section 219, "is perhaps more properly characterized as reducing a regulatory barrier—the potential lack of recovery of costs—to infrastructure development."[48]

The Commission should update its policy, however, to make these non-ROE incentives automatically available (subject to a section 205 filing) for projects that are approved through a regional planning process. As discussed more fully in EEI's comments, there are many reasons that a project may be abandoned that are outside of the project developer's control, including a determination by the RTO or ISO that the project is no longer needed. Particularly in regions that can direct transmission owners to construct projects, allowing transmission owners to automatically be eligible to recover 100 percent abandonment costs for projects selected in a regional plan can alleviate the risk that the region may direct the cancellation of such projects. Further, the Commission should expand the abandoned plant incentive to allow the costs of unsuccessful Order No. 1000 proposals to be recovered through regulatory asset or deferred pre-commercial cost-recovery incentives. This would facilitate greater participation in, and development of, Order No. 1000 projects.

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[47] *Id.* at P 117.

[48] *Id.* at P 28.

E. Mechanics and Implementation – Duration of Incentives

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

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 Commission should not limit the duration of transmission incentives.[49] Investors and utilities alike need regulatory certainty to inform decisions regarding long-term planning and the deployment of capital. In particular, transmission companies have long-term investment horizons and assets that have a useful life that extends decades.

Introducing the potential for sunsetting incentives or a reduction of incentives over time due to changed circumstances would inject a level of uncertainty into the utility planning process sufficient to undermine transmission investments. To the extent transmission investment is reduced because of this uncertainty, the impact of incentives would be diluted and would run counter to Congressional intent that transmission incentives be used to ensure reliability and reduce congestion.

Incentives remain central to the development of a more robust transmission grid that will improve reliability, strengthen competitive markets, and enable grid operators to better plan for and address disruptive events. The Commission's incentives policy has been successful in this regard because there has been certainty for utilities that capital, once deployed for a project, will continue to receive incentive rate treatment over the life of the asset. Commission policy, therefore, should not adopt any sunsetting of, or potential revision to, ROE incentives once granted.

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[49] The only exception to this policy would be the sunsetting of the operational excellence adder discussed in Section IV.B which, by design, sunsets each time the Commission evaluates and assesses the operations of transmitting utilities.

F. Incentives and ROE Levels

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 be based on how the Commission sets base ROE?

In Order No. 679, the Commission stated that it would provide ROEs at the upper end of the zone of reasonableness for transmission investments that meet the requirements of section 219.[50] The Commission acknowledged commenters' arguments that transmission incentives need not be cost-based and therefore could justifiably be above the upper-end of the zone of reasonableness.[51] Nonetheless, the Commission stated that it "believe[d] that a return within the zone" would be "adequate to attract new investment and consistent with the intent of Congress in section 219."[52] To attract the level of transmission investment that will be needed to build the greater grid of the future, however, the Commission should revise its policy of limiting a transmitting utility's total ROE at the upper bound of the base ROE's zone of reasonableness.

The transmission investments that result from the Commission's incentives provide direct consumer benefits by ensuring reliability, enhancing the resiliency of the transmission grid, reducing congestion, facilitating state policy initiatives, and bringing new generation resources to market. These investments have enduring value for consumers that, over the long run (*i.e.*, over the life of a facility), will provide significantly greater benefits than any incremental costs associated with a total ROE that may exceed the base ROE's zone of reasonableness. By tying available incentives to the base ROE's zone of

[50] Order No. 679 at PP 91, 93.

[51] *Id.* at P 93.

[52] *Id.*

reasonableness, Commission policy unnecessarily limits the potential consumer and reliability benefits that section 219 was intended to incent. Even if the Commission determines that some upper bound is necessary or warranted, incentive-driven ROEs should be able to exceed the upper bound by some amount. For example, the Commission could adopt a policy that enables a transmitting utility to exceed the upper end of the zone of reasonableness but cap the exceeded amount by 100 basis points.

V. COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to, and the parties request the Secretary to include on the official service list, the following persons, who shall also be authorized to receive notice in this docket:

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** Persons to be included in the Commission's service list are identified by an asterisk. ITC respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.203(b)(3), to allow for the inclusion of more than two persons on the service list in this proceeding.*

VI. CONCLUSION

Transmission is only a small part of consumers' delivered energy cost—generally about 11% nationally. Yet, the majority of the interstate transmission grid was constructed more than 30 years ago and has received only incremental investment since. Today, 70% of transmission lines and large power transformers are more than 25 years old, and this aging transmission system forces customers to pay for increasingly expensive power while keeping cleaner and cheaper alternatives out of the market. Power outages and power quality disturbances alone cost the economy about $100 billion annually.

Unless this aging grid is addressed, the basic reliability of the system will be increasingly at risk, as electricity demand in this country is expected to rise 25% by 2030. The Commission, through its incentives policy, has the opportunity to drive investment in the nation's transmission infrastructure to ensure a more reliable, resilient, and consumer-facing grid of the future. The incremental costs of transmission incentives will be far outweighed by the economic benefits that accrue to consumers as a result of a stable and highly-efficient transmission system.

WHEREFORE, for the reasons articulated above, ITC respectfully requests that the Commission incorporate ITC's proposals into its incentives policy.

Respectfully submitted,

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