UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL COMMENTS OF
ALLIANT ENERGY CORPORATE SERVICES, INC. AND DTE ELECTRIC COMPANY

Alliant Energy Corporate Services, Inc. ("Alliant Energy") and DTE Electric Company ("DTE Electric") (collectively, "Certain TDUs [Transmission Dependent Utilities]") hereby submits these comments in response to the Notice of Inquiry ("NOI") issued by the Federal Energy Regulatory Commission ("FERC" or the "Commission") in the above-captioned proceeding on March 21, 2019.[1] Certain TDUs support the Commission's assertion that, given the significant changes that have taken place in the electric industry, including transmission planning, development, operations, and maintenance, the time is right to reconsider its transmission incentives policy. Certain TDUs provide answers to some of the questions posed in the Transmission Incentives NOI to assist the Commission in its assessment of whether its current policies meet statutory obligations, and whether there is a need to add, modify, or eliminate certain policies or regulatory requirements.

I. COMMUNICATIONS

Alliant Energy and DTE Electric requests that all communications, correspondence, documents, and other materials related to this proceeding be addressed to the following persons:

[1] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, 166 FERC ¶ 61,208, Docket No. PL19-3-000 (March 21, 2019) ("Transmission Incentives NOI").

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II. BACKGROUND

As part of the Energy Policy Act of 2005 ("EPAct 2005"),[2] Congress amended the Federal Power Act ("FPA") to include new section 219,[3] and directed the Commission to utilize transmission incentives "to help ensure reliability and reduce the cost of delivered power by reducing transmission congestion."[4] The Commission, in response, issued Order No. 679[5] that established the Commission's fundamental principles for implementing transmission incentives. Later, the Commission refined its approach via the 2012 Policy Statement,[6] which provided additional guidance regarding the Commission's interpretation of Order No. 679 and how it grants incentives, but did not alter any of the Commission's regulations or the foundational principles of Order No. 679.

The Commission asserts in the Transmission Incentives NOI that, because of the time that has elapsed since the passage of Order No. 679 and the 2012 Policy Statement, it is necessary to "seek

[2] Energy Policy Act of 2005, Pub. L. No. 109-58, sec. 1261 *et seq.*, 119 Stat. 594 (2005).

[3] 16 U.S.C. § 824s (2005).

[4] Transmission Incentives NOI at P 1.

[5] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006) ("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).

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

comment from stakeholders on the scope and implementation of the Commission's transmission incentives policy."[7] The industry has experienced significant developments in the way transmission is planned, developed, operated, and maintained. The Transmission Incentives NOI, therefore, seeks feedback from stakeholders as to how these developments should or should not change the ways in which the Commission implements section 219 of the FPA as required by EPAct 2005, while still maintaining the requirements of FPA sections 205 and 206 to ensure just and reasonable rates, charges, terms, and conditions that are not unduly discriminatory or preferential.

III. EXECUTIVE SUMMARY

Certain TDUs support transmission investment that provides benefits to customers through effective and purposeful planning. Additionally, Certain TDUs recognize the evolution of the electric grid requires continued investment in new technology to maintain grid reliability and resilience, and to meet changing customer demands. While Certain TDUs do not, as a rule, disagree with the idea of transmission incentives to support the needed evolution of the electric grid, it does not support transmission incentives that provide little benefit to transmission customers. To further these objectives, these comments suggest that the Commission adopt a comprehensive benefit-cost analysis that considers benefits to customers, project costs, project need, and the project's associated risks and challenges. Taking all of these factors into consideration allows for a thorough evaluation of whether and to what degree transmission incentives should be awarded based on the overall value of the project. The Commission's base posture should therefore not be simply *what* incentives should be granted for transmission projects; rather, the Commission should first determine *if* transmission incentives should be granted for certain transmission projects, then, examine the circumstances of the project to provide those transmission incentives that best ensure the completion of the project.

Certain TDUs, as transmission dependent utilities, understand the cost burdens associated with

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[7] Transmission Incentives NOI at P 2.

the Commission's current transmission incentives policy. Because customers ultimately pay for the additional costs associated with transmission incentives, the Commission should provide them the opportunity to understand the "what" and "why" of these additional costs. Transmission developers should therefore bear the burden associated with demonstrating a project's need, its benefits, and why it should be awarded any additional transmission incentives. As part of the comprehensive benefit-cost analysis, all parties – the transmission developer, customers, and the Commission – are provided a forum in which they can understand the overall value of a transmission project and whether additional financial incentives are needed to ensure the project's completion.

Additionally, with respect to specific transmission incentives, Certain TDUs delineate between project-based incentives (e.g. abandoned plant) and policy-based incentives (e.g. participation in an Independent System Operator ("ISO") or Regional Transmission Organization ("RTO")). Project-based incentives are those limited to the life of a project and should be awarded for those projects that are particularly risky and valuable to the transmission system. Certain TDUs oppose any characteristics-based project incentives that favor one particular type of project over another. The Commission should be agnostic to the type of project being constructed as long as there is a demonstration of high value. On the other hand, policy-based incentives are those awarded to a transmission owner's entire rate base as a means of furthering some specific long-term policy. If the Commission seeks to achieve a specific policy goal (e.g. participation in an ISO/RTO), Certain TDUs support finite return on equity ("ROE") adders to incent entities to pursue necessary actions and behaviors that would otherwise put investors at risk, yet balances cost impacts to customers.

In sum, Certain TDUs proffer that by adopting a comprehensive benefit-cost analysis, the Commission will 1) provide a demonstration of project need and associated benefits; 2) provide cost transparency for transmission developers and customers; 3) reduce the need for transmission incentives because risk and benefits are now properly monetized; and 4) get the "right" projects built without discriminating between specific project types. If properly structured, this new transmission incentive policy will avoid over-building the transmission system, reduce the amount of unnecessary dollars distributed to transmission owners for low-risk projects, and ensure the continued reliability and resilience of the transmission grid at reasonable cost to customers.

IV. COMMENTS

Certain TDUs respectfully request that the Commission consider the responses provided herein to certain questions posed in the Transmission Incentives NOI as it reexamines its broader transmission incentives policy. The transmission development and construction paradigm has shifted in the intervening years between issuance of the Commission's Order No. 679, the 2012 Policy Statement, and now. Specifically, interest in and development of transmission projects has dramatically increased in the past decade. For example, over the last ten years the Midcontinent Independent System Operator, Inc.'s ("MISO") regional transmission expansion plan ("MTEP") has included 3,171 new projects – a total of over $25 *billion* in transmission infrastructure.[8] MISO has also added a stakeholder group - the Competitive Transmission Developers - that currently contains 29 members[9] whose focus is the development of new transmission projects in MISO.[10] There is obviously no lack of motivation by entities to construct new transmission; instead, the relevant question is *who* should construct (and earn a return) on these projects, and who pays for the projects.

As part of its policy reexamination, the Commission must consider that transmission infrastructure construction is an attractive business to transmission owners, independent developers, and investors, and an operational necessity for ISOs and RTOs. The Commission must therefore first consider whether

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[8] *See* MISO Transmission Expansion Plans for the previous ten years as found on the MISO website at https://www.misoenergy.org/planning/planning-test/mtep-2017/#t=10&p=0&s=FileName&sd=desc.

[9] *See* https://cdn.misoenergy.org/Current%20Members%20by%20Sector95902.pdf for the most current list.

[10] In response to this new sector and new opportunities for other entities to participate in the construction of transmission, transmission owners in certain states have been advocates for establishing an incumbent utility's Right of First Refusal to protect the incumbent's ability to construct transmission that is in high demand.

transmission incentives are actually needed to construct certain transmission projects. Only then should FERC consider how to ensure that available transmission incentives actually drive desired behaviors (i.e. construction of specific types of projects) resulting in benefits to customers. Appropriate transmission investment maintains system reliability, achieves state and federal public policy goals, and provides value to electric customers. Certain TDUs support the use of incentives that bring quantifiable and meaningful benefits to customers and the electric grid, and are necessary to complete such projects.

A. Incentives Based on Project Risks and Challenges

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

Risks and challenges are a relevant metric when evaluating incentive applications; however, these are not the only criteria the Commission should consider. Importantly, benefits to customers, project costs, and project need are other critical factors that must be a part of the Commission's transmission incentive evaluation process. Considering *all* of these factors – risks, challenges, benefits, costs, and needs – is necessary to enable the Commission to perform a thorough evaluation of whether and to what degree a transmission incentive should be awarded.

Related to risk, the Commission first needs to determine for whom it is measuring risk: is the Commission concerned about the risk to investors, Transmission Owners, or customers? As discussed above and in previous pleadings, there is no lack of interest in transmission development.[11] While this by no means implies that entities do not face project-specific risks associated with transmission construction (e.g. siting hurdles or environmental regulations), the Commission needs to decide if it should be concerned that 1) transmission infrastructure will not get built, or 2) what gets built provides sufficient value to customers. The risk definition adopted by the Commission should be directly related to that of investors and shareholders of the transmission developer. Incentives should not be provided for transmission owners assuming risk on behalf of customers, yet no risk is assumed by investors and/or

[11] *See Comments of Alliant Energy Corporate Services, Inc.*, Filed in Docket No. AD19-12-000 (May 28, 2019), p.3.

shareholders.

Second, the Commission must evaluate the underlying issues associated with what motivates transmission build in the first place. Is the project needed? Does the project provide significant benefits? Does the project serve a public policy purpose? It is Certain TDUs' position that all of these factors, to an extent, motivate developers to pursue certain projects. When determining if a transmission incentive should be granted, the Commission must consider how a specific project achieves one or more of these goals. Low-risk/low-reward projects do not warrant transmission incentives because such projects are by their nature an incentive to transmission developers due to the lack of risk. For example, projects normally approved in an ISO/RTO annual reliability assessment planning process (e.g. MISO's MTEP or PJM Interconnection, LLC's ("PJM") Regional Transmission Expansion Plan ("RTEP") processes) do not warrant incentives because such projects do not either pose significant risk to transmission owners or provide benefits at a level significant enough to warrant incentive treatment.

Certain TDUs do not object to the Commission's policy of providing transmission owners with incentives to encourage particular projects and/or to meet specific Commission policy goals, when there is a demonstrated need. Certain TDUs encourage adoption of project-specific evaluations as opposed to blanket authorizations. A policy of blanket authorization does little to drive desired behaviors, and may instead encourage overbuild and adds unnecessary costs to consumers. A project-specific evaluation, on the other hand, encourages entities to pursue specific transmission projects that meet specific operational needs or policy goals. Additionally, such a rubric provides the Commission with greater flexibility should operational needs or policy goals change faster than the Commission's administrative rulemaking proceedings. Certain TDUs support a shift away from the narrowly-focused risks and challenges framework for evaluating transmission incentives, to a broader framework that includes risks and challenges as inputs into the Commission's evaluation of value (i.e. benefits in excess of costs) and the corresponding necessity of granting transmission incentives on a project-by-project basis.

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?

As stated above, risks and challenges cannot be the sole proxies for determining benefits. Instead, the Commission needs to consider a variety of inputs for determining the overall value to customers, including costs, measurable and defined benefits, and project need. Not all projects that are "risky" and/or "challenging" are worth constructing; the Commission should incorporate the value (or lack thereof) the project provides to the grid and/or customers as a means of granting transmission incentives. A transmission owner or developer should not be incentivized to pursue a project that is considered especially risky or challenging *only* because it can obtain certain transmission incentives for that project. Because the current "risks and challenges" framework neglects to include a demonstration of commensurate customer benefits, the Commission's current policy encourages projects that would otherwise not be pursued. The Commission's transmission incentive policy should encourage transmission developers to construct high reward-to-cost projects that result in lower overall costs for customers, as required by section 219 of the FPA.

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?

If an existing base ROE already incorporates a project's risks and challenges, the Commission should consider whether additional ROE incentives are necessary. The Commission, in its final determination of an overall ROE, needs to ensure that incentives do not duplicate or double count risks that have already been considered when determining the base ROE. The Commission should also ensure any awarded project management incentives (e.g. Construction Work In Progress ("CWIP") or abandoned plant) are considered before granting ROE adders.

In addition, the Commission should consider, at minimum, the following risk factors when determining a base ROE for a transmission owner: the size of the transmission owner's construction program; its business model and financial structure; whether it is part of a diversified public utility holding company structure; geographic diversity; if it possesses any power supply obligations; and, the state regulatory environment in which it operates. If a transmission owner operates a fleet of generation facilities, the Commission may also consider the characteristics of that fleet (e.g. age of generators, fuel type, etc.) as part of its risk evaluation. Additionally, since the Commission, in some cases, awards base ROEs to groups of transmission owners,[12] as part of its evaluation of transmission incentives to individual transmission owners, the Commission should recognize the different risk profiles of transmission owners in that group. For example, the Commission should consider if transmission owners with high equity levels warrant a lower ROE due to reduced leverage. While RTO-wide base ROEs are a useful starting point, the Commission should allow the Base ROE of each individual transmission owner to be adjusted to reflect such differences such as an entity's capital structure.

B. Incentives Based on Expected Project Benefits

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

The Commission should include a transmission project's expected benefits as part of its determination to grant transmission incentives. To be effective and transparent, the Commission needs to examine proposed transmission projects in a holistic manner: a consideration of risks, challenges, benefits, and need would provide a thorough understanding as to the value of a transmission project and what, if any, incentives should be granted to ensure that project's completion. Considering only some and

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[12] Specifically the New England Transmission Owners ("NETOs") and the MISO Transmission Owners ("MISO TOs"). (*Order on Initial Decision*, Opinion No. 531, 147 FERC ¶ 61,234 (June 19, 2014) ("NETO Order")(Order granting New England Transmission Owners a Base ROE); and, *Order on Initial Decision*, Opinion No. 551, 156 FERC ¶ 61,234 (September 28, 2016) ("MISO TO Order") (Order granting MISO Transmission Owners a Base ROE).)

not all of these factors could lead to superfluous build and unnecessary added costs to customers. Importantly, this approach supports the goals of section 219 by encouraging transmission build that is *prudent* for the system and customers.[13]

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?

The Commission should adopt a benefits approach that incorporates bright-line criteria in addition to general principles. The bright-line criteria should be a specific metric by which benefits should exceed costs before a transmission project qualifies for consideration of transmission incentives (e.g. a project must demonstrate that customers will receive, at minimum, $1.50 in benefits to every $1.00 spent).[14] This minimum baseline allows the Commission to eliminate projects from consideration of transmission incentives that may be required for standard operations or lack any substantial benefit to customers. The Commission would then apply broad general principles in deciding if and what transmission incentives should be awarded to the proposed project. Certain TDUs are generally supportive of risk-reducing incentives for projects that demonstrate significant risks and/or challenges with construction, while transmission incentive adders would be reserved for entities that support specific Commission policies (e.g. RTO participation). The Commission would evaluate each proposed project in totality – risks, challenges, need, cost, and benefits – to incent construction of high-risk/high-reward projects to both customers and investors/shareholders.

[13] 16 U.S.C. § 824s (2005), Part b.4.B. ("The rule shall … allow recovery of … all prudently incurred costs related to transmission infrastructure development.")

[14] Attachment FF – "Transmission Expansion Planning Protocol" – of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff (the "MISO Tariff") states that "The Transmission Provider shall employ a benefit to cost ratio test to evaluate a proposed Market Efficiency Project. <u>Only projects that meet a benefit to cost ratio of 1.25 or greater</u> … shall be included in the MTEP as a Market Efficiency Project and be eligible for cost sharing [emphasis added]." (Section II.B.1.c) It is Certain TDUs' position that, in order for a project to receive an incentive, the project developer should demonstrate that the project has a sufficiently high benefit-cost ratio, where "sufficiently high" means in excess of the minimum, which, in the case of MISO, is 1.25. Therefore, a benefit-cost ratio of at least 1.50 would be necessary to qualify for transmission incentives.

New York's Reforming the Energy Vision ("REV") initiative is an example of how the Commission could integrate the consideration of expected benefits into a prescribed methodology that provides full transparency to stakeholders concerning how a project was evaluated, including specific cost and benefit metrics.[15] Chapter 7 of the Benefits Cost Analysis ("BCA") Handbook details four types of benefits (bulk system, distribution system, reliability/resiliency, and externalities) and four types of costs considered (program administration, utility-related, participant-related, and societal)[16] for various grid projects proposed in New York. Chapter 7 further mathematically defines how each benefit and cost is calculated so that all stakeholders understand the process and, most importantly, the outcomes. The BCA Handbook also has a built-in update mechanism to ensure specific data elements are reviewed and updated as needed, providing New York regulators the flexibility to adjust expected costs and benefits as policies and priorities evolve.[17] Certain TDUs do not necessarily recommend adopting New York's REV procedures; rather, highlighting REV demonstrates that such a benefit-cost approach to evaluating transmission projects is possible.

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

Certain TDUs want to ensure that the right transmission projects are built. To do so, the Commission should provide clarity as to what specific aspects of a project will be evaluated, and include a high benefit-cost ratio for both low-risk and high-risk projects. The Commission's current risks and challenges framework is but one aspect of a more robust evaluation. If left to their own devices, transmission owners may only pursue low-risk projects that may or may not yield high expected benefits. Utilizing a benefit-cost ratio that incorporates risks and challenges along with other criteria provides a reasonable metric to determine that the right transmission infrastructure is built.

[15] Benefit Cost Analysis Handbook, Version 1.1, August 22, 2016. ("BCA Handbook")

[16] *See* BCA Handbook, Chapter 7 - "Benefits and Costs Methodology," pp. 35-71.

[17] BCA Handbook, p.1.

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

Certain TDUs do not support automatic incentives for transmission projects under any circumstances. Section 219 of the FPA requires the Commission to balance the need for transmission investment with consumer costs.[18] Automatic incentives contradict that responsibility. A mere demonstration of "benefits" does not warrant an incentive; rather, the Commission should consider the project's need, costs, risks, and challenges in addition to the benefits that accrue in totality to determine if a project warrants a financial incentive. Consideration of these factors will better determine which projects require and which projects do not require an incentive. For example, a low-risk project that still demonstrates some level of benefit to consumers should not be granted an incentive because the components of the project would fail to demonstrate a need for any incentives.

Additionally, the Commission should not grant an incentive unless an applicant can demonstrate that the entire package of requested incentives is commensurate with risk to both investors and customers, will not unnecessarily increase customer costs, and is needed to get the project built. The Commission has previously acknowledged that all incentives must be considered together as a "package":

> Consistent with Order No. 679-A, the Commission will continue to require applicants seeking incentives to demonstrate how the *total package of incentives requested* is tailored to address demonstrable risks and challenges. Applicants 'must provide sufficient explanation and support to allow the Commission to evaluate each element of the package and the interrelationship of all elements of the package. If some of the incentives would reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE' [emphasis added]."[19]

Therefore, the Commission must consider the need for an incentive, the risk of the project, its benefits, and the impact of the resulting overall ROE (inclusive of all requested and granted incentives) on customer costs before rendering a final decision on a requested incentive. Awarding incentives automatically

[18] 16 U.S.C. § 824s (2005).

[19] Order No. 679–A, FERC Stats. & Regs. ¶ 31,236 at P 27.

ignores the impact to customers and is contradictory to the mandates of section 219 of the FPA; that is, the Commission should balance the reliability of the system with the cost impacts to customers before making a determination.[20]

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?

While Certain TDUs advocate for the use of a benefit-cost approach to granting transmission incentives, it cautions the Commission from using expected benefits as the only means by which it grants incentives. For example, Certain TDUs could support granting transmission incentives to a project that reaps high expected benefits relative to cost and is extremely risky. These types of projects may not be pursued or constructed because of the risks and challenges associated with the project, although this has not been a problem in the MISO footprint. Certain TDUs would not support granting transmission incentives to a project that reaps high expected benefits relative to cost but is low risk. These types of projects are frequently pursued because transmission developers can reap hefty financial rewards with little risk. In both instances, the determining factor is *not just* the expected benefits of the project; the determination of a transmission incentive is based on a holistic review of the benefits, costs, risks, and challenges of the project.

Additionally, Certain TDUs favor risk-reducing incentives over ROE adders. Risk-reducing incentives are like insurance – a payout that would otherwise not be needed, and is only necessary should something go wrong. ROE adders are financial rewards to transmission developers without any real association with risk. Certain TDUs would support ROE adders for specific projects, but not as a mechanism for an entity's entire rate base.[21] Further, Certain TDUs suggest that the type of transmission

[20] 16 U.S.C. § 824s (2005) Part a.

[21] Transmission incentives related to projects are separate from transmission incentives that seek to achieve a specific policy priority and applied to an entity's entire rate base, as discussed later in these comments. (*See* Responses in Part N.ii. below.)

incentive is less important than the projects that receive incentives. As discussed in the previous paragraph, a project that demonstrates higher risks along with higher expected benefits should receive incentives over the project that is of lower risk.

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?

The Commission should adopt a minimum benefit to cost ratio of at least 1.50 to 1 on a net present value basis over the life of the underlying project assets. A benefit-cost ratio sufficiently in excess of 1:1 is needed to account for the inherent uncertainty in transmission planning and warrant an incentive for the project. This benefit-cost ratio would not be static since the Commission could adjust the ratio for a number of reasons. For example, the ratio could be adjusted if uncertainty associated with the benefit calculations is high (i.e. a higher ratio may be required if the benefits received are more uncertain than a typical project). The benefit-cost ratio could also be adjusted to account for any direct financial incentive provided as a cost (i.e. a post-incentive benefit-to-cost ratio).

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?

The Commission should apply incentives to those costs submitted as part of the benefit-cost estimates submitted in its application for incentives. To encourage investment and accurate cost estimation, discourage low- ball cost estimates, and protect customers from significant cost over-runs, any granted incentives would apply only to the costs approved as part of the initial incentive application. If a transmission developer incurs additional costs above those provided in the initial cost estimate and seeks to have any granted incentives applied to those costs in excess of the initial cost estimates, the transmission developer can submit another application for incentives that would allow the Commission and interested stakeholders to determine if the additional costs were prudently incurred, provide benefits to customers, and are worthy of incentives. Allowing incentives to apply to the cost estimate provided in the initial application gives certainty to transmission developers and investors, while requiring an additional application for any cost over-runs protects customers from costs that might have been imprudently incurred.

In some cases, like with larger transmission projects, it may be necessary for the Commission to require informational filings from transmission developers, including at the completion of a project, to relay information associated with the actual costs incurred for the project. Requiring informational filings as part of the incentive process allows the Commission and other interested stakeholders to know the *actual* costs incurred during the construction of a project, and if those costs still justify the expected benefits. Access to this information protects consumers from significant cost over-runs that may impact the initial benefit-cost analysis; ensures transmission developers are transparent about construction costs; and, protects customers' interests related to the project's final benefits and costs.

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?

For those projects located in an ISO/RTO, FERC should require transmission developers to include ISO/RTO-specific benefits in its request. For example, if an ISO/RTO seeks to minimize congestion in a certain area for operational purposes, the transmission developer would point to that ISO/RTO priority as a benefit to consider when granting incentives.[22] All costs associated with the construction of a project should be incorporated into the benefit-cost analysis for purposes of determining if and to what degree transmission incentives should be awarded (e.g. costs related to siting approvals, regulatory approvals, materials, etc.).

Regarding verification, as discussed above, any cost over-runs experienced by the time the project

[22] For example, Attachment FF of the MISO Tariff utilizes Adjusted Production Cost ("APC") to identify economic benefits from the proposed construction of a Market Efficiency Project.

goes into service can receive incentives if the project developer files an application that demonstrates the additional costs were prudently incurred and provide benefits in a manner similar to the initial incentives application. Such an approach ensures that cost estimates are made in good faith; investors continue to receive the returns granted before construction began; and, customers are not saddled with the costs associated with unnecessary over-runs. In addition, as noted above, for certain projects, the Commission may require informational filings to ensure transparency of final project costs and that benefit thresholds remain intact. Certain TDUs want to encourage appropriate transmission construction, but not in a way that overly burdens customers at the expense of investor returns.

C. Incentives Based on Project Characteristics

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?

Section 219 of the FPA requires the Commission to establish "incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[23] Adoption of a project-based framework for evaluating transmission incentive characteristics is instrumental to ensuring transmission construction actually benefits consumers. A project-based evaluation allows the Commission to evaluate all aspects of the project before determining what, if any, incentives should be awarded. A project-based evaluation would require transmission developers to demonstrate the project's need, associated risks, challenges, and benefits – all of which provide transparency to stakeholders and allows for a thorough examination of how the project "benefit[s] consumers" as required by section 219.

[23] 16 USC 824s (a).

Certain TDUs posit that a project-based framework would result in different outcomes than that which has been seen historically: a comprehensive project-based approach would avoid costly and unnecessary granting of transmission incentives under the Commission's current policy. Certain TDUs emphasize its support for transmission incentives that are necessary to constructing high-risk/high-reward transmission projects because it believes such projects ensure reliability and reduce transmission congestion to the ultimate benefit of electricity consumers as required by section 219. However, transmission incentives must be prudently applied and not granted for standard transmission projects that provide little benefit to consumers. A project-based approach to granting transmission incentives accomplishes this by providing a transparent, comprehensive process that allows incentives to be awarded to valuable projects.

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?

The Commission should establish general principles that incorporate certain bright-line criteria for identifying and evaluating project characteristics it considers when determining transmission incentives. Providing general principles for how incentive applications will be evaluated allows for transmission developers to tailor requests to the specific project at issue. General principles to be evaluated would assure that project need, benefits, costs, risks, and challenges are all considered, along with any additional policy goals the Commission deems necessary of pursuit. Transmission developers would, however, bear the burden of demonstrating how/why specific project characteristics warrant a transmission incentive or increase the risk associated with construction of the project. A project's unique characteristics are just another input into the Commission's examination of a project's overall value.

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?

The Commission could establish general project characteristic categories (i.e. use of advanced technologies, congestion reduction, ISO/RTO-specific needs, etc.) against which it measures the proposed project. If that project meets a certain threshold number of categories, the Commission would be more likely to grant that project a transmission incentive. Importantly, the project characteristic criteria would be but one factor in the Commission's assessment of a project's need for a transmission incentive. The Commission would still need to demonstrate its value to the transmission grid and customers via a thorough benefit-cost analysis.

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

Certain TDUs do not advocate for a reversal of the Commission's current risks and challenges framework; instead, it is seeking to expand the Commission's procedures to include other considerations in its determination of granting transmission incentives. Adopting an approach that incorporates a project's unique characteristics would provide greater certainty to transmission developers as well as transmission customers. The benefit-cost approach recognizes that all transmission projects are different – in need, cost, associated risk, and benefit – and awards incentives based on the entirety of the proposal. Utilizing a cost-benefit approach to awarding transmission incentives on a project-by-project basis allows all affected stakeholders to see the benefits of a project and why said project should receive transmission incentives, if any. Certain TDUs' proposal would narrow the use of transmission incentives to those projects that provide benefits in significant excess of costs (at least 1.5:1.0). A significantly risky project that demonstrates significant benefits would be awarded transmission incentives that are tailored to that specific project. Transmission developers would know the base threshold that a project needs to meet before applying for transmission incentives.

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

No; transmission projects should not be awarded incentives automatically as no two transmission projects are the same. Before granting an incentive, the Commission must carefully consider all factors of a transmission project, including technical and cost factors; the perspectives of stakeholders (including those that will be responsible for paying the costs associated with the project); and, the overall transmission policy currently in effect before granting any transmission incentives.

D. Reliability Benefits

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?

The Commission does not need to tailor or create incentives to promote reliability projects. The North American Electric Reliability Corporation ("NERC") already possesses that responsibility.[24] Any incentives tailored to address reliability needs duplicates the actions in which NERC already engages; the Commission, therefore, should not provide an incentive to transmission owners to comply with mandated standards. Further, enhancing the reliability of an already-reliable system is not a prudent use of investor or customer dollars.

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

It is Certain TDUs' opinion that there are very few instances that merit reliability transmission incentives. NERC continuously evaluates emerging reliability risks and establishes baseline requirements for Transmission Owners to meet. Transmission Owners should not be rewarded transmission incentives for pursuing projects that need to be completed in order to meet minimum NERC requirements.

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?

Should the Commission choose to tailor incentives to reward reliability benefits, he Commission

[24] NERC's responsibilities include "develop[ing] and enforce[ing] Reliability Standards; annually assess[ing] seasonal and long-term reliability; monitor[ing] the bulk power system through system awareness; and educat[ing], train[ing], and certifi[cating] industry personnel." *See* "About NERC" at https://www.nerc.com/AboutNERC/Pages/default.aspx.

should undertake a similar evaluation of customer value for the proposed project. Reliability improvements can manifest in myriad ways. Instead of providing a transmission incentive for projects that "enhance reliability," the Commission should encourage transmission developers to seek the optimal transmission solution to an identified problem. Adopting this approach to transmission incentives would encourage transmission developers to seek the solution that provides the greatest benefit to customers at a reasonable cost.

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

Certain TDUs question the rationale of incentivizing the construction of transmission facilities that expand access to essential reliability services because there is no clear understanding of what behavior or policy is being pursued. Utilities are already tasked with ensuring reliability as part of standard operations. For example, the Commission already requires that generators provide certain essential reliability services[25] without an incentive because there is recognition that these services are indeed *essential* to the efficient operation of the grid. The Commission should not incentivize entities to provide services necessary to the base operation of the grid. Incentivizing a "high-level of reliability" could encourage over-building the transmission system without demonstrating commensurate benefits.

E. Economic Efficiency Benefits

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

ISOs/RTOs already have well-established and routine transmission planning processes in place that specifically focus on transmission solutions that reduce congestion where the estimated benefits of a

[25] *See, e.g., Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (June 16, 2016).

project outweigh the cost. Further, the Commission already promulgated Orders[26] that require ISOs/RTOs to promote reliability projects. For example, more recently, in July 2011, the Commission issued Order No. 1000 to address certain issues related to transmission planning and cost allocation. In that Order, the Commission noted a number of projects that would be available for competitive bidding processes, including projects that enhanced economic efficiency.

Since the publication of Order No. 1000, ISOs and RTOs have implemented FERC-compliant processes that encourage the development and construction of projects that produce significant economic efficiency benefits.[27] As there is already a FERC process in place to encourage economic efficiency projects, Certain TDUs are opposed to creating another financial incentive for projects that reduce congestion or facilitate access to additional generation. The competitive bidding processes FERC established in Order No. 1000 are sufficient for ISOs/RTOs to attract needed investment. The relevant hurdle to constructing economically-driven projects is cost allocation and the establishment of appropriate cost allocation mechanisms. Without fair and transparent cost allocation mechanisms, much-needed transmission projects (i.e. those that are high-risk/high-reward) are abandoned because of disputes over who will pay.

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?

The Commission should first establish a meaningful benefit-cost analysis to demonstrate the

[26] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, No. 12-1232, 2014 WL 3973116 (D.C. Cir. Aug. 15, 2014); *see also*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[27] For example, MISO implements a comprehensive congestion planning process regularly. Market Efficiency Projects ("MEPs") are the result of these studies that examine both low voltage and high voltage projects. Providing incentives for these projects would not drive any new construction behavior; instead, such a proposed policy will only stand to increase customer costs.

project's need based on the overall value to customers. Instead of establishing bright-line metrics for transmission projects to receive transmission incentives, Certain TDUs suggest that overly risky, costly, or challenging projects be competitively bid. Utilizing bright-line economic efficiency metrics should not be the deciding factor as to whether a project is awarded a transmission incentive. If a project is overly risky, a competitive bidding process will appropriately monetize that risk by considering the added costs associated with the project. After a bid has been selected, the transmission developer can seek risk-reducing incentives for the project, but not be eligible for transmission incentive adders as such a request would skew the underlying benefit-cost analysis.

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?

Certain TDUs caution against encouraging transmission projects that facilitate the interconnection of additional generation outside of a formal interconnection process. It is Certain TDUs' position that the Commission must maintain a strong link between those that pay for granted incentives and those that benefit from transmission development. That is, the Commission must adhere to the "Cost Causation" principle.[28] Should the Commission choose to encourage transmission that facilitates the interconnection of generation outside of formal generation interconnection processes, the Commission must be aware they could be promoting a policy that results in significant cost shifting between customers. For example, in MISO, new generators connecting to the grid are only responsible for those transmission costs identified in the formal generation interconnection process. Transmission targeted to connect new generation and developed outside of the formal generation interconnection process, would not result in the primary beneficiaries (i.e. new generators) sharing in these costs. Allowing new generation favored

[28] As defined in *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("…it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.")

status to transmission is neither just nor reasonable, and is unduly discriminatory.

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?

Certain TDUs reiterate their opposition to incentivizing transmission projects that facilitate the interconnection of additional generation outside of a formal interconnection process; however, if the Commission chooses to establish benefit metrics, it is important that the metrics are defined and narrow in scope. Certain TDUs recommend that the Commission provide the opportunity for each individual region, including ISOs and RTOs, to create their own region-specific benefits metrics that reflect the regional characteristics of the operating region. Allowing for regional flexibility ensures that the Commission is committed to recognizing the various operational needs and incorporating those needs into its decision-making process.

F. Flexible Transmission System Operation

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

The transmission grid has become more dynamic with the inclusion of new technologies (including renewable energy resources, battery storage devices, and other non-wires alternatives). Devices that have flexible operating characteristics increase reliability, allow for more variable renewable energy production, and optimize utilization of the system. Oftentimes, the flexibility required to overcome a transmission issue is of short duration – may be a few hours throughout the year. Traditional wires solutions assume the issue is present every day of the year, and are constructed to operate every day of the year, instead of a few hours a year. Ultimately, the grid operates more efficiently and customers see savings through lower operational costs when flexible, non-wires alternatives are considered to address certain transmission issues.

Certain TDUs are particularly supportive of non-wires alternatives (to the extent they comply with NERC standards) as solutions to transmission issues because of their cost effectiveness. For example, Certain TDUs support Distributed Energy Resources ("DERs") because of their flexibility and the benefits they provide to the system and customers. Other non-wires alternatives, such as batteries or Static VAR Compensators, should also be considered as viable and cost-effective solutions when these technologies meet NERC requirements. The Commission could also consider other flexible resource options like dynamic line ratings, which allow for seasonality and load changes; and, load management options such as Demand Response through aggregation of load management or DER management. The goal for all of these non-wires alternatives is efficient asset utilization.

Like any other proposed solution for transmission issues, DERs, energy storage devices, or other non-wires alternatives should be evaluated based on a benefit-cost ratio. If these alternatives can demonstrate materially better benefits achieved to costs incurred, such alternatives should be approved by the Commission and considered for incentive treatment, if requested. The Commission should encourage transmission providers and owners to consider non-wires alternatives to transmission issues where they provide benefits to the grid and to customers through better asset utilization.

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

The Commission should not provide an additional incentive for flexibility if a traditional benefit-cost analysis is used. Such an approach identifies those solutions that have the highest benefit ratio. It is incumbent upon transmission owners to find the best value solution to identified issues, including the evaluation of integrating new technologies or local load/distribution options. Certain TDUs request that the Commission, during its evaluation process, be agnostic as to what constitutes a "best solution." Construction of new transmission should not be the default solution to solve a transmission-related problem; a process that includes the evaluation of non-wires alternatives should be part of any solution set. If non-wires alternatives were considered but rejected, that information should be provided in any transmission project application. Certain TDUs are concerned that transmission owners are biased towards new transmission construction for reliability or constraint problems, when what is needed is the project that provides the best value for customers, which can be a non-wires solution. As a transmission dependent utility, it is Certain TDUs' expectation that transmission providers and owners identify best value solutions for customers at all times.

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

The Commission should avoid specific characteristics-based incentives because a given characteristic may or may not create benefits, depending on the project. For example, "flexibility" is a broad and somewhat nebulous term; attempting to define it narrowly may ultimately limit how it is considered in a benefit-cost analysis and hinder the development of a needed project. The Commission should instead adopt a policy that evaluates projects and their characteristics on a case-by-case basis.

G. Security

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?

A secure grid is essential for transmission owners and operators, as well as generation owners and operators, and Certain TDUs support prudent physical and cybersecurity enhancements that ensure a safe and secure grid. However, entities should not be financially rewarded for engaging in standard practices that allow the grid to provide safe and affordable electricity to consumers.

Alliant Energy submitted comments in response to a recent Technical Conference co-hosted by the Commission and the U.S. Department of Energy ("DOE").[29] In that proceeding, Alliant Energy stated its opposition to providing incentives to physical and cyber security enhancements at transmission facilities. Alliant Energy, along with DTE Electric, reiterates that position in the instant proceeding.

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?

[29] *Security Investments for Energy Infrastructure Technical Conference*, Docket No. AD19-12-000 (March 28, 2019); *see also Comments of Alliant Energy Corporate Services, Inc.*, Filed in Docket No. AD19-12-000 (May 28, 2019).

Certain TDUs reassert its opposition to the creation of a "security" transmission incentive. The Commission should avoid including investments for "security" purposes that are simply baseline measures that need to be deployed (i.e. those investments associated with NERC standard compliance). Certain TDUs continue to assert the Commission's need to adopt a benefit-cost analysis for purposes of granting transmission incentives. Utilizing a benefit-cost approach would allow transmission owners and developers to pursue projects that utilize innovative features or new technologies that exceed baseline security requirements as long as those projects have a high benefit-to-cost ratio via a transparent process. Those proposed projects that have a high benefit-to-cost ratio would be granted priority for obtaining a transmission incentive over projects with a lower benefit-to-cost ratio, regardless of the characteristics that give rise to the benefits and costs.

H. Resilience

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

Certain TDUs do not believe transmission projects that enhance resilience should be eligible for incentives. The Commission previously suggested that transmission projects be given incentives for "reliability-enhancing attributes."[30] In other forums, the Commission has discussed "resilience" as an attribute worthy of financial incentives.[31] The definition of "resilience" as currently contemplated by the Commission[32] is such that there are multiple avenues by which a system can enhance its "resilience," including through reliability measures, new technologies, or non-transmission alternatives. Certain TDUs are concerned that if the Commission pursues a "resilience" incentive that generally targets reliability-

[30] *See* Transmission Incentives NOI at section II.B.1.

[31] *See Security Investments for Energy Infrastructure Technical Conference*, Docket No. AD19-12-000 (March 28, 2019).

[32] *See Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures*, 162 FERC ¶ 61,012 (January 8, 2018) at P 23, *citing* the National Infrastructure Advisory Council's *Critical Infrastructure Resilience Final Report and Recommendations* at 8 (September 8, 2009): "The Commission understands resilience to mean: '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.'"

enhancing attributes, for example, the result could lead to a project receiving multiple incentives for the same characteristic, while raising costs unnecessarily. Instead of focusing on individual attributes, the Commission should adopt an approach that looks at a proposed project's attributes in totality to determine if the benefits exceed the costs of construction before awarding any transmission incentives.

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

Certain TDUs do not support a "resilience" incentive because the benefits of such an incentive are already captured by other processes and standards with which transmission owners must comply. For example, NERC's reliability standards, ISO/RTO planning for contingencies, and transmission planning to account for future needs could all be considered an element of "resilience" that does not need financial incentives for completion because they are necessary for the day-to-day operations of the grid. The Commission should refrain from pursuing transmission incentives that reward transmission owners and developers for investing in basic, routine projects that are required for the daily grid operation and for projects that capture region-specific benefits in current transmission planning processes.

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

Similar to its position regarding the definition of "flexibility," Certain TDUs reiterate their position that FERC should avoid adopting a specific characteristics-based incentive approach since a given characteristic may or may not create benefits. Instead, each project and its specific characteristics need to be evaluated holistically. Like "flexibility," "resilience" is a broad and somewhat nebulous term; attempting to define it may ultimately limit how it is considered in a benefit- cost analysis and harm the consumers who pay for transmission projects.

I. Improving Existing Transmission Facilities

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.

Certain TDUs continue to assert that use of a properly-constructed and transparent benefit-cost analysis will incentivize construction of the "right" solution to a transmission project that utilizes the necessary technologies to maximize the value of that project to customers. Utilizing a benefit-cost analysis that examines *all* possible solutions for a transmission issue can incent transmission owners to consider non-wires alternatives and existing infrastructure, including technologies that enhance the capacity, efficiency, and operation of the transmission grid like dynamic line ratings. If a benefit-cost analysis is properly implemented, projects that enhance the operation of the transmission grid by utilizing existing infrastructure can be measured against the default choice of building new infrastructure in a manner that chooses the most valuable project for the grid and grid customers.

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?

The Commission should distinguish between those incremental improvements to the grid that merit an incentive and those maintenance-related expenses that transmission owners should make in its ordinary course of business. A distinction can be made by examining the penetration and frequency of use of the technology in general operations. Technologies that are widespread and highly regarded as necessary (either through best practices or NERC standards) would *not* qualify for an incentive since they are part of the ordinary course of business. New technologies that are not widely adopted nor possess any NERC or FERC compliance standards would need to demonstrate their use and value to the grid when requesting an incentive, but should be eligible for such an incentive.

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

Certain TDUs suggest that a transmission owner seeking a new technologies incentive should compare the project using the technology to a "best alternative project" that would not utilize the technology in an effort to demonstrate the benefits and value associated with the new technology. If the benefit-cost ratio of the project that utilizes the new technology is significantly greater than that of the "best alternative project" that does not utilize the technology, the Commission would consider awarding an incentive for that project. Importantly, the Commission should not foreclose the opportunity for stakeholder input where projects that purport to use new technologies are considered for incentives. Any awarded incentive will have a cost impact on transmission customers; therefore, those customers should be afforded the opportunity to comment on proposed new technologies and be provided a demonstration of benefits and value before the Commission renders a decision regarding an incentive.

40. Should the Commission provide a stand-alone, transmission technology-related incentive? If the Commission provides a standalone 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?

Certain TDUs support incentivizing new technologies through various means, but does not believe that eligible technologies should be given an automatic incentive. Again, Certain TDUs are not opposed to characteristic-based transmission incentives, and encourage the Commission to instead adopt a comprehensive benefit-cost analysis for approving projects and any associated transmission incentives. As part of that analysis, transmission developers would still be required to demonstrate the technology's need and associated benefits. Similarly, as "new" technologies become "standard" technologies for day-to-day business operations, the Commission should periodically revisit the definition of an eligible technology so that entities do not receive incentives for technologies that are now deemed "maintenance-related" or "standard." If the Commission's policy is to incent innovation, maintaining financial incentives for technologies and practices that are no longer "innovative" only serves to add costs to customers without supporting a stated policy or providing commensurate benefit.

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?

Certain TDUs offer that, to the extent costs are reflected in operations and maintenance ("O&M") categories and formula rate cost of service rates, regulatory asset treatment is not warranted. Allowing regulatory asset treatment would serve three purposes: 1) to spread the cost recovery of the asset over a longer period of time; 2) to allow for increased review of the costs prior to inclusion in rates; or, 3) to allow for another opportunity earn a return. However, such regulatory asset treatment is not necessarily beneficial to customers, and, in some cases, redundant to already existing processes. Customers are already provided a reasonable opportunity to challenge the prudency of costs through audit protocols. These steps will not necessarily incent specific behaviors as the Commission intends, but may increase costs to customers in the long run. The Commission should therefore not pursue regulatory asset treatment as a means of incenting new technologies. Should the Commission authorize such regulatory asset treatment, then it is appropriate that the regulatory asset be included in rate base as the transmission owner will have made the investment but not yet recovered the costs from customers.

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 could require ISOs/RTOs to adopt better grid management technologies or other technologies by initiating a rulemaking proceeding. However, with the lag time of a rulemaking proceeding, the Commission could first require informational reports for how the ISO/RTO is best utilizing its assets. From there, the Commission could either compile a "best practices" for ISOs/RTOs or proceed with a formal rulemaking that would include mandates and compliance requirements that ensure ISOs/RTOs consider all options available to promote efficient use of the transmission system and improve market performance.

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.

Certain TDUs support the use of performance-based ratemaking to ensure that ROEs reflect cost-saving measures associated with the deployment of software upgrades, technologies for faster ramping, or other non-wires alternatives that enhance the transmission system. For example, utilizing technology that reduces the total cost of transmission services could be shared between the customer and the transmission owner without increasing overall ROEs. Transmission Owners would be incentivized to reduce cost as opposed to the current system that rewards adding rate base. No matter what efforts are employed by transmission owners to better utilize the existing system, Certain TDUs encourage the Commission to require that the actions taken are transparent so that transmission dependent utilities, transmission providers, and customers can associate the costs incurred with the benefits received.

J. Interregional Transmission Projects

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?

The Commission should not favor one type of project over another (i.e. interregional transmission projects vs. regional transmission projects). The Commission should establish a policy that is agnostic to project type (e.g. interregional, regional, economic efficiency, public policy) and focus on the project's specific risks and benefits. Creating category-specific incentives instead of evaluating transmission projects holistically and on a case-by-case basis could lead to certain projects being built in favor of more necessary projects simply because of the financial incentives made available. The Commission's transmission incentive policy should be based on a proposed project's risks and benefits and specific characteristics to ensure that projects are being built to enhance the grid and efficiently serve customers, and to avoid haphazard transmission incentive awards.

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?

Certain TDUs again caution the Commission against adopting policies that favor one type of project over another. Should the Commission choose to pursue a policy that encourages interregional transmission projects via transmission incentives, it should do so on the basis of a benefit-cost analysis similar to that discussed throughout these comments.

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

Certain TDUs again assert that classification as an interregional project does not alone merit a transmission incentive. The project developer should be required to prove its need through a demonstration of reliability, economic, or other benefits. Establishing a policy based on need and benefits accrued avoids favoring one type of project over another and the potential for added, unnecessary costs.

K. Unlocking Location-Constrained Resources

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?

The Commission should avoid creating an incentive that seeks to "unlock" location-constrained resources. ISOs and RTOs already engage in interconnection processes that identify transmission needed to facilitate the interconnection of resources in an efficient manner, as well as reoccurring comprehensive congestion studies. Should the Commission choose to create such an incentive to "unlock" location-constrained resources, it should adhere to a policy that encourages projects with a high benefit-to-cost ratio and in accordance with the concept that beneficiaries pay, allocating these costs directly to the resource owner that benefits from the transmission project. Location-constrained resources do not face interconnection hurdles because of where they are sited; instead, the problem is ensuring that the resource owners that benefit from the new transmission pay the associated costs.

If the Commission chooses to create an incentive that encourages transmission development to location-constrained resources *outside of already-established processes*, those who pay for the transmission project and those who benefit from that same transmission project could be misaligned. Also, as previously stated, constructing transmission is not the problem; the problem is ensuring a cost allocation scheme that properly conforms to the "Beneficiaries Pay" principle. Certain TDUs therefore request that the Commission forego adopting an incentive that targets transmission development to location-constrained areas.

L. Ownership by Non-Public Utilities

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

The same rules should apply to non-public utilities as to public utilities. Non-public utilities should be provided the same opportunity to compete in bidding processes for transmission projects, and should comply with the same proposed requirements of demonstrating a project's need, risks, challenges, and benefits when seeking transmission incentives. The Commission should not provide incentives for joint ownership arrangements. Such arrangements are based on the financial interests of the companies involved as opposed to the transmission siting decisions made by ISOs and RTOs.

M. Order No. 1000 Transmission Projects

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

The Commission should not create nor automatically grant a new incentive for transmission projects selected in a regional transmission plan for purposes of cost allocation. Granting additional incentives on top of a selected bid negates the purpose of a competitive bidding process. For example, if a transmission developer wins a bid for a transmission project because, among other things, it is the lowest cost proposal, but then seeks transmission incentives that no longer make the bid the most attractive (at least in terms of cost), the competitive nature of the bidding process is lost. The Commission could allow the opportunity for transmission developers to request and for the Commission to grant risk reducing incentives to transmission developers that win a competitive bid. Risk reducing incentives do not necessarily increase the overall cost of a project, but provide safeguards to transmission developers that pursue risky projects. To make the competitive bidding process more efficient, a specific set of expected incentives upon which all bidders could rely when preparing project bids would be desirable. The ISOs/RTOs can take responsibility for defining the set of expected incentives prior to beginning the bidding process.

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

Certain TDUs do not support automatic incentives for any transmission projects. As stated throughout these comments, the Commission should require projects 1) meet a specific benefit-cost ratio (i.e. 1.5:1), and 2) be a high-risk and challenging investment to both investors and customers in order to qualify for any incentive. Transmission projects that are the result of a competitive bidding process should not be a determinant as to whether incentives are warranted; instead, the entirety of the project's need, benefits, risks, costs, and challenging should determine if and to what extent incentives should be granted.

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?**

Certain TDUs posit that non-incumbent transmission developers should have the same opportunity to seek risk reducing incentives as those allowed to incumbent transmission developers. The Commission should not interfere with regional competitive transmission processes by encouraging bid distortions through after-the-fact transmission incentive adders. Risk reducing incentives, however, can be sought by non-incumbent transmission developers. Certain TDUs do not take a position as to whether such incentives should be sought under section 205 or section 219 of the FPA; rather, Certain TDUs are concerned with ensuring transparent processes so that customers benefit from the best lowest cost solution to resolve specific grid issues.

N. ROE-Adder Incentives

i. Transmission-Only Companies

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?

In Order No. 679, the Commission stated that "Transcos' for-profit nature, combined with a transmission-only business model" provides the benefits of "enhance[d] asset management and access to capital markets and provides greater incentives to develop innovative services."[33] As the customer of a Transcos for over a decade, Certain TDUs are not persuaded by these assertions.

As previously stated, transmission owners currently do not face financing problems. Whether the transmission owner is a Transco or not has little or no impact on a transmission owner's ability to secure financing for transmission projects in the current investment environment. Easy access to capital *reduces* the perceived risks associated with the Transco model, that is, providing an ROE that is "sufficient to attract investment"[34] and not warrant a transmission incentive adder. As evidence, ITC Midwest was in operation between 2007 and 2015 without receiving the Transco Adder,[35] yet still able to attract sufficient capital for projects during that period. The Commission's underlying reasoning in Order No. 679 for

[33] Order No. 679 at P 224.

[34] *Id.* at P 221.

[35] *See ITC Holdings Corp.*, 121 FERC ¶ 61,229, at PP 39-45 (2007). Certain TDUs recognize that the denial of ITC Midwest's request for the Transco Adder was not a substantive rejection, but rather because "ITC Midwest has not demonstrated that its proposed 13.88 percent ROE is within the range of reasonableness," and not because ITC Midwest was ineligible for the incentive. (*Id.* at P 39) However, Certain TDUs note that ITC Midwest operated and found capital from the time of the decision - December 3, 2007 - through March 31, 2015, when the Commission approved a 50-basis point adder for ITC Midwest. *See Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,252 (March 31, 2015) ("In this order, we conditionally accept ITC Midwest's request to implement the Transco Adder, subject to it being reduced to 50-basis points and applied to a base ROE that has been shown to be just and reasonable." P 2.)

creating a Transco Incentive Adder therefore should have been the reasoning for *not* creating a Transco Incentive Adder: because Transcos do not compete with other affiliates for capital, there is little concern that these entities will be unable to find sufficient capital.

With respect to the incentive for the development of "innovative services," Certain TDUs, who are the customers of Transcos, have not been the recipient of any particular "innovative services" that would warrant a transmission incentive adder. For example, in Alliant Energy's experience, most of ITC Midwest, LLC's ("ITC Midwest") efforts have been overhauling the already existing transmission system after its subsidiary, Interstate Power and Light ("IPL") sold its transmission assets to ITC Midwest in 2006. ITC Midwest's investments in overhauling the existing system have been significant, but could not be classified as "innovative" to the point of necessitating an added return. Most of ITC Midwest's investments would be classified as part of the normal course of business, requiring an adequate return on investment, but not a transmission incentive adder. Similarly, in DTE Electric's experience with its transmission owner, ITC*Transmission* ("ITCT"), most ITCT projects address core reliability needs to meet NERC standards, load interconnections, or asset renewal. All of these categories of projects are in the normal course of business and should not be incentivized.

As part of its evaluation, the Commission should determine what and how a Transco Adder supports long-term policy goals, if at all. Certain TDUs contend that there is no long-term policy goal associated with the Transco Adder and it should be eliminated. If the Transco incentive remains, any entity seeking the incentive must provide evidence that demonstrates specific benefits that would not otherwise accrue to customers under another ownership model.

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?

The Transco Adder should not be awarded to Transcos that are affiliated with a market participant. Order No. 679 defined a Transco as "a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility."[36] Order No. 679 sought to provide flexibility when examining various business models to determine if an entity qualified for a Transco Adder and the magnitude of the awarded incentive. Certain TDUs offer that an affiliated Transco does not possess the characteristics sought by the Commission detailed in Order No. 679.[37]

Alliant Energy's subsidiary, IPL, jointly filed a complaint at FERC with other ITC Holdings Corporation's ("ITC Companies") customers in April 2018.[38] The April 2018 Complaint argued that because the ITC Companies were acquired by an entity that possessed generation assets, the ITC Companies could no longer be considered an "independent transmission company" as defined by the Commission and therefore should no longer receive the Transco Adder.[39] In its ruling, the Commission found the ITC Companies' level of independence was reduced when it was acquired by Fortis, but not completely eliminated.[40] The October 2018 Order found that with respect to investment planning, capital formation, and business structure, the ITC Companies' "demonstrate some level of independence"[41] that warranted retention of the Transco Adder. The Commission, however, found that because the level of independence was reduced, the Transco Adder should also be reduced – from 50-basis points to 25-basis points.

Commissioner Glick dissented from the majority ruling, noting that the Commission's incentive policy "must balance the need for new transmission facilities with its obligation to ensure rates that are just and reasonable and not unduly discriminatory or preferential [footnote omitted]" and that any

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[36] *See* Order No. 679 at P 201.

[37] *Id.* at P 224. ("By eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed.")

[38] *See Complaint of Consumers Energy Company, et. al.*, in Docket No. EL18-140-000 (filed April 20, 2018).

[39] At the time, ITC Midwest was receiving an additional 50-basis points for qualification as a "Transco." (*See Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,252 (March 31, 2015).

[40] *Consumers Energy Company et al. v. International Transmission Company et. al.* Order on Complaint. 165 FERC ¶ 61,021 (October 18, 2018) ("October 18 Order") at P 68.

[41] *See* October 2018 Order at PP 69-71.

awarded incentives "must incentivize transmission owners to develop and operate their facilities in a manner that provides consumers with *sufficient benefits to justify the extra costs they must pay*."[42] Alliant Energy agreed that the ITC Companies fail to demonstrate sufficient benefits associated with the added costs of receiving a Transco Incentive Adder. As with any transmission incentive, Certain TDUs support a demonstration of benefits when incurring added costs. When a previously-classified Transco is acquired by an affiliated market participant, the Transco should bear the burden to demonstrate that 1) it maintains adequate independence from the affiliated market participant, and 2) the Transco provides benefits that outweigh the costs associated with the incentive adder. Failure to make these demonstrations should result in the elimination of the Transco Adder.

The current implementation of the Commission's Transco incentive policy does not fulfill any policy need. As such, the ITC Companies continue to receive an additional 25-basis points for classification as a "Transco" despite now competing for capital with generation assets – a Transco characteristic lauded by the Commission in Order No. 679. A Transco cannot be affiliated with other market participants and still maintain its semblance of "independence." The Commission's attempt to encourage independent transmission companies is unnecessary because the current environment experiences no competition for capital in the industry and interest in constructing transmission projects remains high amongst a variety of entities. As part of its reexamination, the Commission should therefore eliminate the Transco Adder and, if found necessary, create other transmission incentives that encourage FERC's long-term public policy goals.

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

Certain TDUs reassert their opposition to the continuation of the Transco Adder and believes it should be completely eliminated for the reasons discussed above. As the Transco Adder is a policy-driven incentive, there is no rationale for it to be awarded on a project-by-project basis should the Commission

[42] October 2018 Order, Glick Dissent at P 2 [emphasis added].

determine that it should be retained.

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

Certain TDUs again reassert their opposition to the continuation of the Transco Adder and believes it should be completely eliminated. Should the Commission perceive some continued value associated with granting the Transco Adder, it should *not* apply to any assets a Transco purchases or acquires. The Transco model was developed to encourage investment in *new* transmission, not assets that are already in the ground.[43] The Commission's stated policy goal of encouraging independent transmission companies because it "eliminate[s] competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment" allows Transcos "to develop innovative services."[44] Acquisition of existing transmission assets does not further the development of "innovative services;" instead, it only serves to increase the Transco's rate base.

ii. RTO/ISO Participation

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

The Commission should revise its implementation of the RTO Participation Transmission Incentive Adder ("RTO Adder"). Both the RTO Adder and the Transco Adder are policy-based incentives as opposed to project-based incentives. The RTO and Transco Adders seek to induce specific actions by Transmission Owners and Developers that is outside the realm of transmission construction (and its associated risks). As the Commission reviews its entire transmission incentive policy, it needs to ensure that it does not conflate *policy* incentives with *project* incentives. Transmission customers should not be responsible for the costs associated with the individual business decisions of a transmission developer that do not serve a specific policy objective.

62. Should the Commission consider providing incentives other than ROE adders

[43] *See* Order No. 679 at P 202 and P 226.

[44] *See* Order No. 679 at P 224.

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?

The Commission needs to maintain a distinction between transmission incentives that encourage specific behavior choices and further long-term policy goals (i.e. joining an ISO/RTO) and those transmission incentives that support appropriate transmission development. Conflating the two different types of transmission incentives will merely increase costs to customers without providing demonstrable benefits. Should the Commission determine that there is continued value in encouraging ISO/RTO participation, it should retain its policy of providing a transmission incentive adder.

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

Should the Commission decide to continue its policy of providing a transmission incentive adder for ISO/RTO participation, it is Certain TDUs' position that an appropriate level for such an adder is no greater than 25-basis points (as opposed to the current provision of 50-basis points). The reduction would reflect the low-risk associated with joining an ISO/RTO as the transmission planning and processes have matured. Also, ISOs/RTOs have absorbed more responsibilities (e.g. NERC compliance) that further reduce the burden on transmission owners. Therefore, as ISOs/RTOs provide increased value to transmission owners in various ways, transmission owners' risk associated with ISO/RTO membership is reduced, prompting a need for a reduction in the adder.

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

It is Certain TDUs' position that policy incentives should be finite. If, in this case, the purpose of the RTO Adder is to incent *joining* an ISO/RTO, a transmission incentive in perpetuity does not provide benefits commensurate with the intended goal. The benefits provided from ISO/RTO membership have increased over time, reducing the need for the adder as transmission owners reap multiple benefits for the same action.[45] Additionally, at this point, entities that have joined ISOs/RTOs face a significant penalty for leaving that ISO/RTO, as well as incurring the risk associated with no longer reaping the administrative, planning, and compliance benefits of ISO/RTO participation. A perpetual transmission incentive adder, therefore, does not factor into an entity's decision to continue ISO/RTO participation as much as the financial penalty or switching costs associated with leaving. FERC should provide an incentive for policy-based actions over a finite and typically shorter-term than those incentives that are awarded for the life of a project.

Certain TDUs support ISO/RTO participation because of the benefits accrued by having access to centralized organized markets. Given the Commission's intended goals of encouraging a transmission owner to *join* an ISO/RTO, Certain TDUs would propose a generic sunset provision (e.g. five or ten years depending on the ISO/RTO) for new entrants. For existing members, Certain TDUs envision a grandfathering provision that allows for the RTO Adder to sunset after a period of time. Certain TDUs recommend that the Commission allow ISOs/RTOs - via their respective stakeholder processes - to determine an appropriate sunset provision for both new entrants and existing participants. Because ISOs/RTOs have different characteristics and provide varying services to its members, benefits provided to consumers are not and should not be assumed to be uniform. A case-by-case approach to a sunset date for the RTO Adder would balance regulatory certainty sought by transmission owners with costs incurred by transmission customers.

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

Transmission incentives that are not project-based (i.e., the Transco and RTO Adders) are counter to Certain TDUs' basic premise that the highest benefit-to-cost ratio projects should be constructed in

[45] MISO performs an annual Value Proposition that quantifies the regional benefits it provides through "enhanced reliability, more efficient use of the region's existing transmission and generation assets, and a reduced need for new asset." From 2007 through 2018, MISO's Value Proposition estimated that it provided the region an estimated $24 billion in cumulative net benefits. *See MISO Value Proposition* at https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/.

spite of higher transmission owner risk per dollar of rate base. If FERC determines that there is specific, non-project-related policy actions needed, those actions and how to incent them should be addressed outside of the project-based incentive process. The RTO Adder is not a project-based incentive and should thus not be applied on a project basis.

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?

Section 219 of the FPA requires that the Commission "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization,"[46] but does not require voluntary participation. Reiterating the position that ISOs/RTOs operate in different environments, the voluntary nature of the ISO/RTO in which a transmission owner is participating could be a factor in determining the length of time an RTO Adder can be collected by ISO/RTO participants. If transmission owners are required to participate in an ISO/RTO, the length of time those transmission owners collect the RTO Adder should be shorter than for those transmission owners that do in fact volunteer to participate in such an organization. Because the statute requires an incentive for RTO/ISO participation, the voluntary nature of participation is a condition imposed at the discretion of the Commission; however, the Commission should consider the voluntary nature of participation when approving the duration of this incentive adder.

iii. Advanced Technology

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

Certain TDUs encourage the Commission to consider the benefits associated with a new technology transmission incentive before creating one. Certain TDUs supports encouraging deployment of technologies that will provide benefits to the grid (and ultimately customers), but cautions against blanket

[46] 16 U.S.C. § 824s.Transmission infrastructure investment.

incentives that fail to consider benefits to customers. The Commission should also define what qualifies as "new" and for how long such an incentive would apply (i.e. the life of the project or until technologies are no longer considered "new" but "standard"). Provision of a perpetual transmission incentive when technologies become standard or obsolete does not align with Certain TDUs' perspective that customers be the main beneficiaries of transmission incentives.

O. Non-ROE-Adder Incentives

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

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?

Certain TDUs support continued use of CWIP and abandoned plant as an incentive, and potentially as an automatic incentive for competitively bid projects only. Certain TDUs do *not* support granting 100% abandoned plant as an incentive, however, because transmission developers need to incur some portion of project risk. An automatic 50% abandoned plant incentive fairly balances the risk associated with a project between the developer and consumers.

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?

Certain TDUs do not support the recovery of costs associated with unsuccessful Order No. 1000 proposals as those costs are part of doing business. Transmission developers receive a return on investment when a project is successfully completed because of the risks associated with developing that project (including unsuccessfully bidding to construct a project). Providing an incentive to transmission developers to recover costs associated with an unsuccessful bid only encourages non-viable bids to be part of a competitive bid process.

ii. Hypothetical Capital Structure

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?

The Commission should eliminate the policy that allows transmission owners to utilize a hypothetical capital structure as a transmission incentive. First, an entity's capital structure is not a very transparent metric that properly reflects risk. Second, an entity's capital structure has no relationship to a project's risk. If the Commission adopts a project-by-project approach to granting transmission incentives, awarding a transmission developer a hypothetical capital structure does not consider the *project's* risk. Additionally, granting a hypothetical capital structure to a transmission developer is an indefinite and systemic incentive without demonstrable benefit. The Commission should focus its efforts on awarding risk-reducing incentives that carefully consider the project's risk to ensure that incentives are tailored to ensure maximum benefit at the lowest cost.

iii. Accelerated Depreciation

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

Certain TDUs take no position as to whether or not transmission owners should utilize accelerated depreciation. However, should an entity choose to use accelerated depreciation as part of its project, then the effects of accelerated depreciation should be utilized as an input into the benefit-cost calculation. Accelerated depreciation – like other transmission incentives – should not be included in an after-the-fact manner as an incentive because doing so would distort the results of any benefit- cost calculation, with the potential of increasing customer costs.

P. Duration of Incentives

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?

Certain TDUs strongly encourage the Commission to provide the flexibility to eliminate or modify transmission incentives based on material changes to the transmission project or circumstances of the transmission owner. As it relates to transmission projects, a transmission incentive would be reviewed if the estimated benefit- cost ratio significantly changes for any number of reasons (e.g. increased costs due to siting challenges or vendor problems). The transmission developer would be responsible for reporting any material change to the transmission project via an informational filing. Interested parties would be afforded the opportunity to challenge the project's new benefit-cost ratio inclusive of any associated transmission incentives previously granted by the Commission. The Commission would then need to conduct a new, formal analysis to ensure that the project still maintains a base level of benefits to customers. Incentives could be eliminated if found to no longer be necessary, or if the Commission finds that elimination of such incentives increases the customer benefits over the base threshold.

As transmission incentives relate to transmission owners, Certain TDUs encourage the Commission to continue to allow petitions for declaratory order or complaints when interested parties have evidence of a material change in the company's position to warrant reexamination of a company-wide incentive. As discussed previously in these comments,[47] Certain TDUs were parties to a complaint that sought to rescind the Transco Adder of the ITC Companies.[48] The complaint alleged, and the Commission found, that the circumstances of the ITC Companies after acquisition by Fortis warranted a reduction in the incentive adder the ITC Companies received for being an independent transmission company. Though the Commission did not eliminate the Transco Adder, Certain TDUs appreciate that the Commission was willing to undertake a review of the circumstances under which the ITC Companies were operating and if those circumstances warranted a transmission incentive adder. Certain TDUs support continuing the Commission's ability to reexamine the circumstances under which an incentive is granted when raised by stakeholders.

[47] Refer to the responses provided in Section N.i. of these comments.

[48] *See* October 18 Order at P 68.

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

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?

The benefits associated with granting incentives on a case-by-case basis include transparency and ensuring appropriate transmission infrastructure is built. Establishing an automatic approach based on an established threshold may provide additional certainty to transmission developers, but will prohibit other interested stakeholders the opportunity to understand why such incentives were granted and what associated benefits will be experienced. Certain TDUs posit that the Commission's base posture should not be *what* incentives should be granted for transmission projects; instead, it should be *if* any transmission incentives should be granted. Transmission developers should bear the burden associated with demonstrating a project's need, and also why a project should be awarded any additional transmission incentives. Transmission customers ultimately pay for these added costs; transmission customers thus have a right to understand the "what" and "why" of such additional costs.

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

Certain TDUs do not believe that any transmission incentives should be awarded automatically. As part of the proposed case-by-case approach to granting transmission incentives for which Certain TDUs continues to advocate, the Commission should consider each project on a stand-alone basis. Automatic incentives usually result in excessive costs to customers without commensurate benefit. Since each project is unique, the Commission needs to consider all aspects of the project before determining what, if any, transmission incentives are applicable.

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

Certain TDUs support the Commission's continued use of the case-by-case approach to evaluating and granting incentives, but suggests the current implementation of this approach can be improved. The

Commission's mandate is to ensure "just and reasonable" rates under the FPA,[49] which, in practice, should strike a balance between providing transmission developers a fair rate of return and protecting customers from excessive and unreasonable costs. To ensure a proper balance, Certain TDUs recommend the following improvements to the Commission's evaluation process.

- Require transmission developers to provide a comprehensive demonstration of the project's need and why the incentive is necessary in order for the project to be constructed.
- Require applicants to provide a comprehensive benefit-cost analysis to demonstrate the project's value to customers (as discussed throughout these comments).
- Evaluate the requested incentives in the context of current policies and priorities. For example, if the Commission adopts a policy to incent better utilization of current assets, it should consider how a proposal and its associated requested incentives further such a policy.
- Adopt a process to perform a benefit-cost analysis that includes the requested incentives to demonstrate how those requested incentives (including risk-reducing incentives) alter the previously-accepted benefits ratio. If the Commission decides that one or more transmission incentives are warranted, conducting an updated benefit-cost analysis will provide interested parties a thorough understanding of the benefits associated with the project as well as the requested incentives.

As a result of these suggested enhancements transmission developers and customers will possess reasonable transparency into a project's benefits and associated costs – an important factor FERC should consider when approving any transmission project – and ensure that it conforms to the FPA's "just and reasonable" standard.

R. Interaction between Different Potential Incentives in Determining Correct Level of ROE Incentives

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?

The Commission should abandon any policy that attempts to broadly categorize highly complex transmission projects. Certain TDUs propose that the Commission adopt a benefit-cost analysis, requiring transmission owners and developers to demonstrate a meaningful showing of need, risks, challenges, and benefits before any transmission incentives are awarded.

[49] 16 U.S.C. § 824d (a).

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?

Order No. 679-A established the Commission's policy to evaluate "the interrelationship between any incentives" to determine whether a project passes the Commission's nexus test.[50] Current Commission policy provides little transparency in understanding how that interrelationship is examined.[51] Certain TDUs suggest that the Commission continue to evaluate transmission incentive requests on a case-by-case basis and include, as part of its evaluation, an analysis of the estimated quantified impact of the requested incentives on both the requesting transmission developer and customers. Such an approach would require the Commission to do an updated benefit-cost analysis that includes the requested incentives to demonstrate how such incentives alter the quantifiable benefits to customers. The Commission, the proposing transmission developer, and customers are provided greater transparency as to the impact of transmission incentives, and granted the opportunity to fully vet a project's value. For example, an amended benefit-cost analysis could provide customers with an idea of how providing CWIP to a transmission project affects the life cycle and year-to-year costs that are paid. Adopting a policy that considers the impact of transmission incentives on a project's costs and benefits creates transparency.

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?

The Commission should maintain its current policy that the total ROE may not exceed the upper end of the zone of reasonableness so that customers are protected from unjust and unreasonable rates. Ideally, if the Commission properly constructs its transmission incentive policy, there would be no need for

[50] *See* Order No. 679-A at PP 20-27.

[51] *See, generally,* 2012 Policy Statement.

a cap on the total ROE as most of the incentives awarded would be risk-reducing incentives. The current policy that allows an ROE to move around within some pre-determined range does not accurately reflect the benefits associated with a project. The Commission's ultimate policy should seek to mitigate a project's risk through available risk-reducing incentives as opposed to granting multiple transmission incentive adders. If the Commission chooses to establish an upper bound on an allowable total ROE, it should continue to use the zone of reasonableness as determined in a base ROE proceeding, utilizing the generally accepted FERC-approved methodology.

S. Bounds of ROE Incentives

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

The Commission should retain full discretion when determining the appropriate level of ROE incentives for a specific transmission project. As discussed throughout these comments, Certain TDUs support a transmission incentive policy that considers the unique characteristics and circumstances of each individual transmission project, calculating the benefits of that project, and ensuring that the costs incurred provide the greatest value to customers. Awarding blanket or automatic incentives to transmission projects does not encourage appropriate transmission build; instead, blanket or automatic incentives results in an inefficient, invaluable, or over-built system that causes financial harm to customers. Retaining the discretion to evaluate transmission projects on a case-by-case basis to determine the appropriate level of ROE incentives ensures that transmission developers are incurring prudent costs that result in prudent and valuable transmission build.

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?

The Commission should avoid blanket authorizations for ROE adders because such a policy would foreclose the Commission's ability to fully vet the need for the incentive. If transmission developers face minimal obstacles to obtaining financing or constructing the project, Certain TDUs question the purpose of incentive adders in the first place. Certain TDUs suggest that incentive adders are actually a *disincentive* for transmission developers to reduce costs because there is no sensitivity to benefit-cost analyses.

The Commission needs to decide if the purpose of transmission incentives is to simply encourage steel in the ground, or encourage thoughtful build-out of the electric grid. As a transmission dependent utility, Certain TDUs want transmission owners to build the high-reward projects so that customers obtain maximum benefits. The Commission's current policy encourages transmission owners to pursue projects that may or may not provide customers substantial benefit. Alternatively, Certain TDUs do not want to hinder transmission owners from pursuing transmission incentives that reward construction of extremely risky but very valuable projects. Utilization of benefit-cost analyses when determining ROE incentives allows the Commission to tailor ROE incentives adders (if any) to the specific proposals without being constrained by arbitrary and costly bounds.

V. CONCLUSION

In closing, Certain TDUs respectfully request that the Commission take these comments into consideration when acting on the Transmission Incentives NOI.

Respectfully submitted,

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June 26, 2019

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010, I hereby certify that I have, on this 26th day of June, 2019, caused a copy of the foregoing Comments of Alliant Energy Corporate Services, Inc. and DTE Electric Company to be sent to each person designated on the official service list compiled by the Secretary of the Commission in Docket No. PL19-3-000.

__/s/ Cortlandt C. Choate, Jr.___

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