UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Improving Transmission Incentives) Docket No. PL19-3-000

JOINT COMMENTS OF PUBLIC INTEREST ORGANIZATIONS ON THE COMMISSION'S NOTICE OF INQUIRY

Pursuant to the Federal Energy Regulatory Commission's (Commission) March 28, 2019 Notice of Inquiry (NOI) in the above-referenced proceeding, the undersigned Public Interest Organizations (PIOs)[1], respectfully submit the following comments on the Commission's scope and implementation of its electric transmission incentives regulations and policy.

I. Introduction and Overview

A. Incentives Have Not Kept Pace with the Transforming Grid

As organizations concerned with the urgent need to develop a modern transmission system capable of quickly integrating the renewable energy resources necessary to combat the climate crisis while growing our nation's economy, we have substantial interests in the Commission's transmission pricing incentives policies and practices. Our comments address many of the questions posed in the NOI, and many of our recommendations are embedded within the answers to the questions.

To summarize, we agree with the Commission's decision to examine and question whether the current incentives framework is producing results. Our answer is that a financial incentive is not, in most instances, the right tool to fix problems with existing transmission policies. A primary interest to our organizations is that very few significant regional or interregional

[1] Acadia Center, GridLab, Natural Resources Defense Council, Sustainable FERC Project, Western Grid Group.

projects have been approved in the last several years, and planning has largely focused on meeting local reliability needs. Additionally, utilities all too often ignore cost-effective advanced technology and other solutions to optimizing capacity and power flows of the existing system.

Furthermore, it is at best unclear as to whether financial incentives of the type and nature the Commission has supported in the last decade are useful for stimulating significant new regional and interregional transmission investment. Under the current planning and cost allocation system, guaranteed incentives simply add additional costs to the project, which, in turn, can undermine the project's attractiveness to the customers who ultimately pay for it.

Instead, it is more likely that other Commission-approved transmission planning and cost allocation policies are providing *disincentives* to meaningful investment that financial incentives alone cannot counteract. For that reason, we encourage the Commission to examine more broadly the barriers to the continuing development and optimization of the bulk power system. Many of these barriers are well-known, including, for example, limited accounting of transmission benefits, the "triple hurdle" required for approval of interregional projects, and the discriminatory status accorded to projects necessary to meet system needs driven by public policy requirements (i.e., planners must only "consider" needs driven by public policy requirements).

B. Statutory and Regulatory Background

Section 1241 of the Energy Policy Act of 2005 (EPAct 2005),[2] codified as section 219 of the Federal Power Act (FPA)[3], directs the Commission to "establish, by rule, incentive-based

[2] Energy Policy Act of 2005, Pub. L. 109-58, sec. 1261 et seq., 119 Stat. 594 (2005).
[3] 16 U.S.C. § 824s (2012).

(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." In 2006, the Commission implemented section 219 by issuing Order No. 679, which established the Commission's basic approach to transmission incentives and enumerated a series of potential incentives that the Commission would consider. The Commission subsequently refined its approach to transmission incentives in a 2012 incentives policy statement, which provided guidance on the Commission's interpretation of Order No. 679 and its approach toward granting transmission incentives but did not alter the Commission's regulations or Order No. 679's basic approach to granting transmission incentives. Notably, while Section 219 requires the Commission to consider transmission incentives, the Commission has independent authority under Section 206 and other provisions of the FPA to address barriers to transmission development that produce unjust and unreasonable rates and undue discrimination.

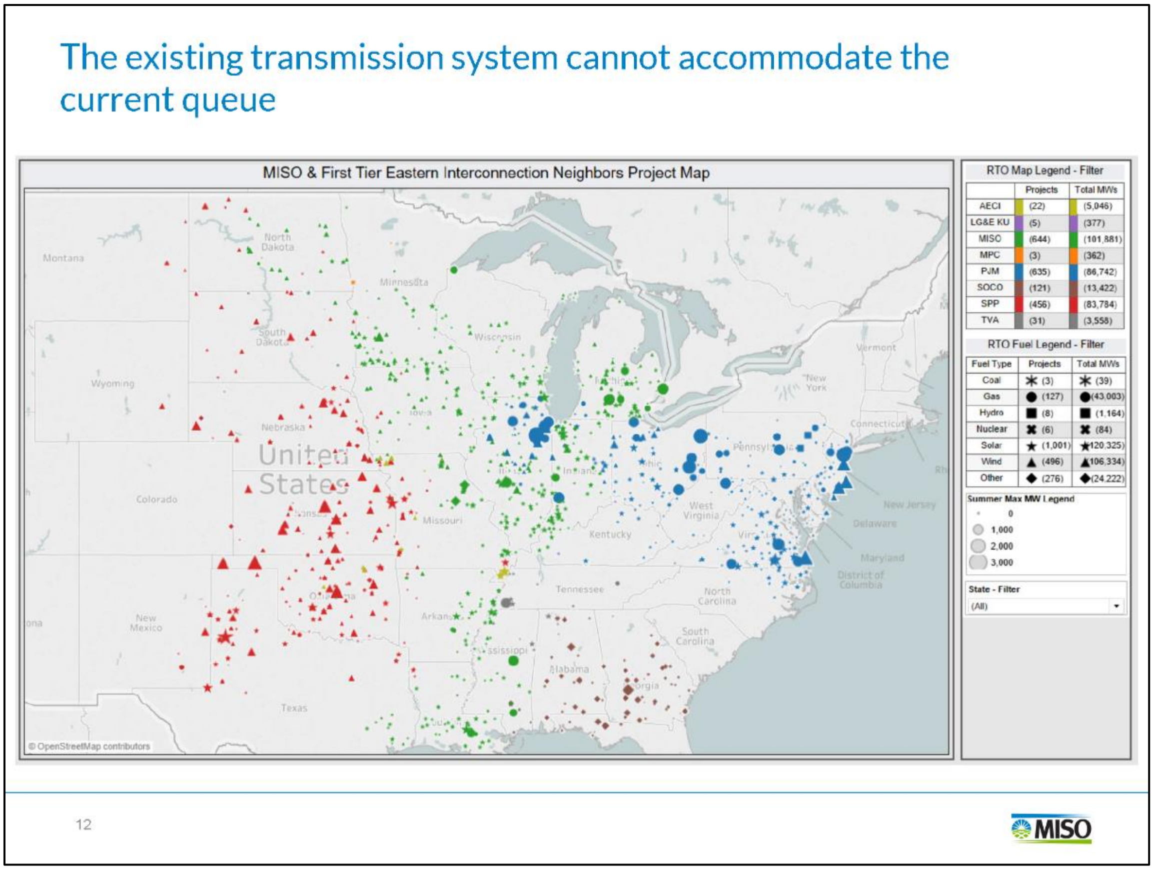
C. The Future Is Now: Pressing Grid Needs and Challenges

In addressing the NOI and its questions, our responses will describe problems with the current inefficient and balkanized power grid, the economic and customer values of an integrated, efficient grid system, and why incentives have fallen short of the Commission's goals. We will examine ways to incent the use of highly-efficient and low-cost operational technologies and grid enhancements and propose alternative incentives – including non-monetary actions – that more directly address and resolve barriers better than the current incentives framework.

Finally, we will emphasize the need for reforms to transmission planning and cost allocation necessary to ensure just and reasonable rates. The nation's electrical transmission system is undergoing a fundamental transformation in several ways. The bulk power system increasingly connects generation sources located farther away from load centers, especially weather-influenced (yet dispatchable) renewable energy resources. Also, the rise of distributed energy resources, especially electric vehicles and other energy storage sources of both load and supply, will add new and variable flows into the system, creating new challenges for a system designed around centralized dispatch. For these and other reasons, the grid increasingly will need to: operate more flexibly than the current system; capture the benefits of large-scale geographic diversity to manage supply integration challenges and costs, while avoiding duplicative and costlier local infrastructure; integrate new technologies to enhance resilience and system coordination; and ultimately link the asynchronous East and West interconnections.

The image below which depicts projects in the interconnection queues of MISO and its Seams neighbors, illustrates the broad geographic distribution of more than 296,000 megawatts (MWs) of energy developments across the eastern interconnection.[4] The image also powerfully demonstrates the rich yet conditional economic development opportunity of renewable energy. Reaching the full potential of renewable energy resources will be dependent on increased transmission capacity from both existing and new infrastructure.

[4] *See* MISO staff, Presentation to the MISO Board of Directors System Planning Committee: Long-Term Resource Adequacy Assessment and Interconnection Queue Update (June 18, 2019), https://cdn.misoenergy.org/20190618%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2003%20Long%20Term%20Resource%20Adequacy%20Assessment354688.pdf (last visited June 26, 2019).



D. Summary of Our Recommendations

The Commission should support financial incentives only in those instances where they actually incent new projects that otherwise would be unlikely to occur. These projects often, but not always, involve the use of advanced or new technology, such as grid efficiency improvement technologies. Critically, any incentives the Commission adopts must reflect cost-causation principles, with benefits commensurate with costs, and all incentives must be shown to be just and reasonable.

The Commission also should use Section 219 and other authorities in the Federal Power Act to support the use of non-financial incentives and other reforms necessary to address the increasingly glaring shortcomings in regional and interregional planning and cost allocation.

Our specific policy reforms supporting these recommendations include:

1. Adopt performance-based and shared-savings incentives for a more efficient use of the existing system and allow new transmission technologies and non-transmission alternatives to compete to achieve such savings at least cost, with transmission owners sharing a small portion of the cost savings from not making larger investments than necessary.
2. Replace the RTO participation adder with an incentive for market participation in the Western Energy Imbalance Market and other sub-RTO markets to encourage the eventual formation of broader regional markets.
3. Reform interregional planning requirements in Order 1000:
    i. Remove the "triple hurdle" approval process.
    ii. Establish cost-allocation standards recognizing the full range of regional and interregional benefits of transmission, including effects on delivered energy costs, allocating the requisite portion of those costs that reflect regional benefits to all customers in all affected regions, regardless of their utilities' contractual status with the new project.
4. Require Order 1000 planning groups to provide historical information on transmission path flows so that developers, regulators and the public understand where new transfer capacity is needed and where existing transfer capacity is underutilized and deny incentives to participants in Order 1000 planning groups that fail to provide information on the utilization of the existing transmission system.[5]

[5] For example, in the Western Interconnection, previously-public information on the historical utilization of transmission paths has been made confidential. Without public access to historical flows on the existing transmission system it is very difficult for: Transmission planners to make

5. Assess the benefits of RTOs, ISOs, and other Order 1000 planning regions joining in a national planning authority to review and consider jointly in a cooperative single planning and cost allocation process, subject to direct Commission approval, proposals to provide high-voltage links among the three interconnections.

II. Answers to Questions in the Notice of Inquiry

Incentives Based on Project Risks and Challenges

Q1: Should the Commission retain the risks and challenges framework for evaluating incentive applications?

Yes, but it should not be the sole framework for evaluating incentive applications. Incentives that can be shown to be just and reasonable and incent needed investment need not be based on either risks-and-challenges or on prospective benefits but can and should incorporate both**.** We discuss the benefits approach in more detail in other answers.

Q2: 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?

Awarding incentives based only on the risks-and-challenges framework inadequately addresses the benefits derived from performance-based approaches which can emphasize and reward efficient solutions employing newer and innovative technologies. These solutions may be better rewarded through a shared savings mechanism based on congestion savings and the

---

a convincing case to potential investors, regulators and facility permitting authorities that new transmission is needed when information on how the current system is being utilized is confidential; generation developers to make sound decisions on the location of new generation when they do not have access to information on historical transmission utilization on all paths in the West where new generation could be located; and the public to accept the need for new transmission if there is little or no public information on whether the existing transmission system is being used efficiently.

aggregation of system benefits. An estimate of production cost savings would be shared between the proposing entity and the customers who would benefit. Coupling the benefits of lower cost and congestion savings would work best for grid operations technologies.

Q3: 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?

Yes, considering risks in calculating a public utility's base ROE and in assessing the availability and level of an ROE adder is still appropriate, but only where the evidence clearly supports an incentive. As the Commission correctly notes, the base ROE includes some degree of risk and challenge. Therefore, any incentives based on risks and challenges should only be reserved for those projects with a materially higher and unusual level of risk or challenge. For example, some incentive might be considered for regulatory risk for interstate lines requiring state by state permitting and approvals, which can diverge widely in both timing and the expectations for project applicants.

Incentives Based on Expected Project Benefits

Q5: 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 can better incentivize transmission by requiring regional planning entities to consider and approve as needed those projects and power management technologies that improve system response, reduce congestion, provide access to rapid and accurate ancillary services, and enhance the dispatch and availability of remotely constrained resources. The benefits of such interregional coordination are far greater than for just one load pocket in a region or one region. This nonmonetary incentive – reforming interregional planning and cost allocation in Order 1000 – would be a powerful tool to drive investment in transmission that provides system flexibility and resilience

General principles should go beyond the alleviation of congestion and include:

- The project enables more efficient use of the existing wires, towers and rights-of-way.
- The project facilitates the development of remotely constrained low-cost resources that might otherwise be stranded.
- The project provides access to complementary renewable energy generation (resources with uncorrelated variability to other variable generation elsewhere in the system) that reduces the need for duplicative balancing or flexible generation within a market footprint.
- The project facilitates a public policy goal such as meeting a carbon reduction standard adopted by a state or combinations of states.
- The project provides resiliency to the system it would not otherwise have.
- All the benefits of transmission should be included as per the WIRES/Brattle report. below.

We agree with the following accounting of transmission benefits by the Brattle Group[6]:

[6] Judy W. Chang, Johannes P. Pfeifenberger, J. Michael Hagerty, Brattle Group, Presentation to the Working Group for Investment in Reliable and Economic Electric Systems: The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments (July 31, 2013), https://brattlefiles.blob.core.windows.net/files/6661_the_benefits_of_electric_transmission_-_webinar_slides_chang_pfeifenberger_hagerty_jul_31_2013.pdf (last visited June 26, 2019).

Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
2. Additional Production Cost Savings	a. Reduced transmission energy losses b. Reduced congestion due to transmission outages c. Mitigation of extreme events and system contingencies d. Mitigation of weather and load uncertainty e. Reduced cost due to imperfect foresight of real-time system conditions f. Reduced cost of cycling power plants g. Reduced amounts and costs of operating reserves and other ancillary services h. Mitigation of reliability-must-run (RMR) conditions i. More realistic representation of system utilization in "Day-1" markets
3. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects b. Reduced loss of load probability or c. Reduced planning reserve margin
4. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses b. Deferred generation capacity investments c. Access to lower-cost generation resources
5. Market Benefits	a. Increased competition b. Increased market liquidity
6. Environmental Benefits	a. Reduced emissions of air pollutants b. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
9. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights, hedging value, and HVDC operational benefits.

Accordingly, the Commission should consider that transmission to high-capacity factor resource areas provides multiple values to the system, and that these values have substantial financial benefits and favorably lopsided cost-benefit profiles. For example, in 2011 MISO found that: "the 17 multi-value projects (MVPs) alone will create $15.5 to $49.2 billion in net present value economic benefits over a 20 to 40-year timeframe. The MVP portfolio provides broad regional benefits commensurate with costs and supports approved state and federal energy policy mandates in the MISO region. In total, the portfolio will deliver benefits in excess of 1.8 to 3.0 times its costs. For retail customers, that translates to $23 in benefits from lowered delivered energy costs for about $11 a year in investment - a 109 percent return."[7]

In addition, multi-value transmission investment can offset a massive number of smaller reliability projects that cumulatively would cost more and could not be completed in the same time frame as multi-value transmission projects. As MISO noted in its summary of the benefits of the 17 MVP projects, MISO considered an alternative plan based on piecemeal resolution of overload issues occurring by the injection of wind into the system. The piecemeal plan would require at **least 650 local transmission projects**, compared with the 17 MVPs.[8]

Finally, at least one ISO has embraced full-benefit accounting in planning. The New York Public Service Commission has required that all public policy projects evaluated in NYISO account for a more complete list of benefits. Accounting for these benefits contributed to the 2018 approval of the NYISO's Western New York and New York AC transmission projects that were bid out competitively and it greatly increases the ability to integrate renewables in upstate New York.[9] Similarly, accounting for this broad range of benefits in other RTOs would facilitate the construction of transmission that would be beneficial to customers. While

[7] MISO News Release, *Transmission Expansion Projects Unanimously Approved*, Dec. 8, 2011, http://capx2020.com/miso/12082011_NR_MTEP11%20MVP%20Approval_f2.pdf.

[8] MISO, *Multi-Value Project Portfolio: Detailed Business Case* at 73 (2011), https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Detailed%20Business%20Case117056.pdf.

[9] Comments of the New York Independent System Operator, Inc. in response to the Proposed Rule Making (December 29, 2014), published in the November 12, 2014, New York State Register, I.D. No. PSC-45-14-00002-P and related matters in the NYPSC's AC Transmission at 2, and Order Finding Transmission Needs Driven by Public Policy Requirements, NYPSC (Dec. 17, 2015).

NYISO looks to the value New York state places on avoided emissions, emissions benefits could be accounted for in multi-state RTOs by using a weighted value in cost benefit analysis and cost allocation decisions, calculated according to the public policies in place in the relevant customers' states.

Q6: How would a direct evaluation of expected benefits, instead of using risks and challenges as a proxy, impact certainty for project developers?

Because current incentives (basis points on ROE) add to the overall balance of project funding that must be financed, they are of little use to transmission development companies. A benefits-based approach allows for performance incentives that allow entities to share the savings projected to be created by the proposed project. A benefits-based approach also rewards efficiency and innovation in transmission solutions and compensation models. For example, performance incentives could allow entities to share the savings projected to be created by the proposed project. Benefits should be forecast on an *ex ante* basis to allow for certainty for the developers and then evaluated on an *ex pos*t basis for the Commission to use in refining its methodology and validating or questioning its approach. Benefits should include the full range of prospective benefits from the proposed project.

Q7: Should transmission projects with a demonstrated likelihood of benefits be awarded incentives automatically? How could the Commission administer such an approach?

As stated in our answer to question 6, we believe that an *ex ante* forecast provides the most useful incentive for developers and encourages efficiency in terms of the selection of both wires and non-wires alternatives. An *ex post* evaluation may be useful in some cases (such as advanced power management technologies), to determine if the forecast was as accurate as could be reasonably expected, though the benefits of new transmission lines accrue over often lengthy decadal time frames so that determining the period in which to evaluate the benefits is difficult.

Q8: 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?

The incentive level should be proportional to the benefits. The Commission may wish to establish some maximum allowed incentive levels for certain types of incentives and limit the downside to consumers. It also would be appropriate to allow an incentive for the benefit of avoided cost, for example the avoided cost of additional generation for balancing or flexibility due to access to lower cost but otherwise stranded generation with a complementary generation shape.

Q9: 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?

Cost-benefit ratios are suitable metrics for establishing incentives based on project benefits, so long as an appropriately wide range of benefits are considered.

Q10: 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 consider basing incentives on an *ex ante* forecast of benefits and can perform an *ex post* evaluation to compare forecast and actual benefits to decide whether to continue a given incentive policy. But to induce action, there should not be *ex post* clawing back of expected revenues. See answer to Question 6.

Q11: 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?

Measurement and verification of benefits would help determine the value of incentives for future projects-and encourage as accurate a forecast of benefits as is possible. Knowing that the forecast will be compared with actual results will discourage over-estimates and reduce the likelihood of gold-plating.

Incentives Based on Project Characteristics

Q12: 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?

Although a project's characteristics may be more easily measured than project benefits and system values, since the characteristics ultimately support meeting the benefits, it is preferable to focus on benefits rather than characteristics. Additionally, a framework based on characteristics might unfairly constrain or limit the range of projects capable of providing system benefits or discourage technological innovation.

Q13: 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?

As noted above, we do not support using project characteristics as a basis for incentives, unless perhaps they are used as a limiting factor on other incentives (e.g., benefits that arise from the use of innovative technologies)

Reliability Benefits

Q17: 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?

We are skeptical of broadly applying incentives to meet reliability benefits. These benefits should be accounted for in a robust planning and cost allocation framework that accounts broadly for system benefits. Reliability-driven projects, whether local or regional, do not appear to face high development barriers – particularly not if they are not part of the full regional planning processes or do not involve regional cost allocation.[10] Reliability benefits should be accounted for in a robust planning and cost allocation framework that accounts broadly for system benefits of regional and interregional projects that provide multiple values beyond reliability. Benefits that enhance system optimization improve access to lower-cost, remotely-constrained resources, improve access to resources with favorable generation shapes (resources having uncorrelated variability with other variable resources over large geographies), reduce GHG emissions, and enhance system reliability. The Commission should encourage investments that provide multiple values and do not narrowly addresses only reliability needs. Many reliability-only investments, particularly local projects that are not part of the full regional planning process, create lost opportunities to provide substantial and multiple additional values, often at no or little incremental costs.

Q20: Should the Commission incentivize transmission facilities that expand access to essential reliability services, such as frequency support, ramping capability, and voltage support?

To the maximum extent possible, grid services (including essential reliability services as a subset) should be procured through market mechanisms, preferable in a co-optimized way in the real time market (and in the day ahead market when necessary). Economic transmission planning processes should be improved to account for potential cost reductions in procuring essential reliability services. Improving transmission assets is an important part of the ERS equation. For example, when the choice is between a costly long-term reliability must-run (RMR) contract and new or upgraded transmission, the better choice for consumers usually is clearly in favor of the transmission asset. Whether incentives would help to stimulate that planning for ERS, as opposed to better economic planning and cost allocation, is unclear. As stated above, an

[10] For a listing of such projects, see MISO, *MISO 2018 Transmission Expansion Plan* at Appendix A (2018), https://cdn.misoenergy.org/MTEP18%20Full%20Report264900.pdf (summarized on page four of the report).

"incentive" may just worsen the cost allocation challenge. If an incentive demonstrably accelerates the transmission solution and reduces or eliminates the cost of the RMR, we would support it, if the assessment of the ERS need includes non-wires solutions and the Commission exercises its authority to provide cost allocation for those non-wires solutions as well.

Q21: If so, how should the Commission assess and measure whether transmission projects expand access to essential reliability services?

See above in response to questions 17 and 20. We are skeptical that incentives would meaningfully stimulate additional necessary transmission investment and recommend instead a more expansive form of economic transmission planning to incorporate ERS cost reduction benefits.

Economic Efficiency Benefits

Q22: Should the Commission tailor incentives to promote projects that accomplish the outcomes of reducing congestion or facilitating access to additional generation?

Yes. Economic efficiency improvements created by transmission operation or expansion warrant incentives, to the extent incentives are demonstrated to help both reduce congestion and connect new resources to load. However, prior to offering such incentives, the Commission should require that the applicant provide a public assessment of current and historical levels of transmission utilization and why new transfer capacity is needed, and why the incentive is necessary to stimulate the investment. For example, in the Western Interconnection, information on the level of usage of existing transmission is not public information. Industry non-disclosure agreements have made previously public historical transmission path flow information confidential. The Commission should not offer incentives to fix "congestion" which has not been publicly documented. For that reason, if the Commission establishes incentives for congestion relief, it should require that the applicant provide a public assessment of current and historical levels of transmission utilization and why new transfer capacity is needed. Economic efficiency should also consider the broad range of benefits that transmission investments can provide (see response to Question No. 5)

Q23: 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?

We propose a methodology above based on shared savings of the benefits. It does not include a bright-line metric, other than the benefits exceeding the costs. It is important to note that with after-the-fact assessments, reductions in delivered energy costs will vary from forecasts and be subject to numerous external factors such as gas prices and demand growth, so clawing back incentives will reduce the regulatory certainty required for investment.

Persistent Geographic Needs

Q26: Should the Commission utilize an incentives approach that is based on targeting certain geographic areas where transmission projects would enhance reliability and/or have particular economic efficiency benefits? If so, how should the relevant geographic areas be identified and defined? What entity (e.g., the Commission, RTOs/ISOs, state regulators, other stakeholders) should designate such areas?

While we question the need for financial incentives to motivate these projects (beyond incentives discussed above, such as those providing additional benefits), non-financial policy incentive reforms are necessary, and the Commission should explore whether to add additional considerations to the planning and cost-allocation process. Broadly speaking, policies should prioritize access to resources that: enhance system optimization; provide access to lower cost remotely constrained resources; provide access to resources with favorable generation shapes, *i.e*. resources having uncorrelated variability with other variable resources over large geographies; reduce GHG emissions; enhances system resilience, improve utilization of the existing grid. See our responses to question 44 and subsequent questions.

Q27: What criteria should be used to define such geographic areas? Procedurally, how should such geographic areas be determined, monitored, and updated?

There have been well-documented cases where geographic areas denoted as renewable energy zones have guided transmission planning decisions, such as in the Texas and California CREZ processes. These identified resource rich areas and identified transmission corridors with appropriate capacities to bring their energy to load centers. In Texas, these lines were afforded system-wide cost allocation in recognition of their power flow benefits to the overall system and the benefits of providing low cost high quality renewable power sources to all Texas customers. In California the Tehachapi transmission project unlocked 4500 Mw of transmission capacity to send wind generation from the Tehachapi wind resource area to loads centers in the Los Angeles basin.

Some criteria for selecting renewable energy zones recommended by NREL are:

- Resource quality
- Topography
- Compatible land use
- Developer interest
- The theoretical renewable energy resource potential (unconstrained by cost or land use issues).[11]

We would add the following characteristics that facilitate system optimization and increase overall project benefits to NREL's list mentioned above:

- Uncorrelated generation shapes to other zones
- Diversified resources available across to-be-connected regions
- Facilitates access to low-cost generation
- Transmission service will enhance system operation
- Decreases the need for reserves on a regional scale

[11] Nathan Lee et al., National Renewable Energy Laboratory, *Renewable Energy Zone Transmission Planning Process: A Guidebook for Practitioners* 6 (2017).

Flexible Transmission System Operation

Q30: Should the Commission incentivize flexibility characteristics and, if so, how should it do so?

The Commission can incentivize transmission providing greater system flexibility by requiring regional planning entities to consider and approve as needed those interregional projects and power management technologies that improve system response, reduce congestion, provide access to rapid and accurate ancillary services, and enhance the dispatch and availability of remotely constrained resources, greater than just for one load pocket in a region. This nonmonetary incentive – reforming interregional planning and cost allocation in Order 1000 – would be a powerful tool to drive investment in transmission that provides system flexibility and resilience.

Q31: How could the Commission define "flexibility" in this context?

Flexibility should be defined as the ability to provide rapid and accurate access to generation and grid services that can provide for uninterrupted and economically-efficient electricity service under a variety of conditions including but not limited to: equipment failures, sabotage, natural disasters, or other contingencies.

System flexibility is best provided by power management technologies in combination with a large scale, interconnected, geographically-diverse set of resources with varying generation shapes uncorrelated both in time and operation. Dispatch of these resources across a regional market and across multiple regional markets can help:

- Smooth out the variability of renewable generation by using the transmission system as a virtual battery, absorbing generation during surplus production in one area and releasing generation from others when the wind stops, or the sun goes down. The ability to take advantage of these resources instantaneously makes the system much more flexible and economically efficient, offsetting the need for duplicative reserves and peaking generation.

- Facilitate the addition of large sources of low-cost remotely constrained renewable resources.

- Accelerate recovery from contingencies or natural disasters by providing alternative means to supply what might otherwise be stranded load.

- Provide access to system resources such as inertia and frequency response and do it rapidly and accurately, taking advantage of the advanced power electronics capabilities in wind and solar inverters. This enhances not only system flexibility, but its resilience and reliability.[12]

- Enhance power flows and relieve congestion.

- Accommodate the introduction of system monitoring and automation technologies that can provide the ability to self-heal in the event of a failure. This facilitates reliable and rapid responses to system changes enhancing flexibility, resilience and reliability.

Security

Q32: Should the Commission incentivize physical and cyber-security enhancements at transmission facilities? If so, what types of security investments should qualify for transmission incentives? What type of incentive(s) would be appropriate?

No. The importance of security is great enough that transmission projects should be required to build-in a high level of security.

Resilience

("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.")

Q36: If the Commission were to grant incentives for measures that enhance the resilience of the transmission system, what incentive(s) would be appropriate?

[12] For a detailed explanation of the ability of renewable generation to provide essential grid services, see Debra Lew & Nick Miller, GE Energy Consulting and Hickory Ledge, Presentation to the Committee on Regional Electricity Policy Coordination, Western Interstate Energy Board: Reliability Implications of our Future Grid (October 24, 2018), https://westernenergyboard.org/wp-content/uploads/2018/10/10-26-18-crepc-wirab-lew-miller-reliability-implications.pdf (last visited June 26, 2019).

The Commission can incentivize transmission that provides greater system resilience by requiring regional planning entities to consider and approve as needed interregional projects that improve system response, reduce congestion, provide access to rapid and accurate ancillary services, and enhance the dispatch and availability of remotely constrained resources, greater than just for one load pocket in a region. This nonmonetary incentive would be a powerful tool to drive investment in transmission that provides system flexibility and resilience.

Financial incentives to introduce system monitoring and automated response technologies or other devices that can change system impedance (flow controllers), or other capacity expanding tools like high capacity conductors may also be appropriate. These could take the form of the proposed "shared savings" proposal we described in our introduction and our answer to questions 37 and 38 below.

Improving Existing Transmission Facilities

Q37: 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.

Improving transmission capacity or efficiency through adoption of upgraded technology and power management technologies that enhance the capability of the existing grid warrants incentives. PIOs recommend that the incentive be based on the savings from avoiding more expensive investment through new standard wires and equipment, with the incentive split between the applicant and customers. Examples of these technologies and management approaches include: dynamic line ratings, power flow control, storage-as-transmission, and topology optimization among others. We also address this question in other responses.

Q38: 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?

Yes, the Commission could determine if the improvements allowed for greater available transmission capacity within the existing right of way, and if that enhancement resulted in reduced congestion, enhanced reliability, resilience, or other benefits (including benefits listed in our answer to Question 5). The Commission could further exclude expenditures for routine maintenance which will be approved by state regulators in rate proceedings. For example, did the improvement harden a facility to withstand credible risks of fires and floods? Did it alter power flows to reduce congestion? Does the improvement facilitate faster redispatch of resources in the event of a contingency? If an improvement resulted in increasing the resilience and flexibility of the regional system in which it is made, it should qualify for either a single measure or a bundled set of measures the incentive for which could be provided through shared savings between the customers and the developer.

Q39: How should a transmission owner seeking this type of incentive demonstrate increases or improvements in the capabilities or operations of existing transmission facilities?

Power flow and congestion revenue rights analysis and considering the changes to LMPs being hedged in the RTO markets are two potential ways to measure system benefits worthy of incenting. As mentioned previously, the cost of avoided replacement facilities could be compared with the magnitude of improved system performance and the resulting financial benefit shared between the applicant and the customers.

Q40: Should the Commission provide a stand-alone, transmission technology-related incentive? If the Commission provides a stand-alone transmission technology-related incentive, what criteria should be employed for a technology to be considered as meriting an incentive? Should the Commission periodically revisit the definition of an eligible technology?

As we suggest in answers to other questions, a technology specific incentive might be useful to accelerate the adoption of such tools as flow controllers, high-capacity conductors and automation, topology optimization, and other technologies that enhance operations and optimization, and maximize utilization of the existing system. Given the relatively low cost of these measures individually, the Commission should consider bundling measures into a portfolio of upgrades to create a more financially beneficial and therefore more effective incentive.

Q41: 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?

Yes, utilities should have the option to include system operations investments as a regulatory asset. This was an important consideration by Public Service Company of New Mexico in its decision to make system improvements to join the Western Energy Imbalance Market[13].

Q42: 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?

Not directly. Monetary incentives have little value for regional planners and should more appropriately be focused on transmission sponsors or developers of the advanced technology. The RTO/ISO is, or should be, required to manage a planning process that identifies and selects a wide variety of transmission system improvements. For example, the CAISO planning process seeks input from stakeholders about potential solutions including new technologies and has mechanisms for evaluating non-wires alternatives including devices like Smartwires technology, high temperature/low sag conductors, storage, and any others. The Commission also should require all Order 1000 regional planning entities to evaluate the costs and benefits of better

[13] Public Service Company of New Mexico, Application of PNM for Approval of an Accounting Order Governing PNM's Investments & Expenditures to Join the Western EIM, New Mexico Public Regulation Commission Docket # 18-00261-UT at 2 (Dec. 20, 2018), http://164.64.85.108/infodocs/2018/8/PRS20254003DOC.PDF (last visited June 26, 2019).

technologies and operating practices (whether alone or in packages), to promote the more efficient use of the transmission system.

The Commission also should establish as a minimum requirement that all grid planning regions evaluate actions that could increase transfer capacities by alleviating System Operating Limits and Interconnection Reliability Operating Limits.

Q43: 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.

Yes, the Commission should include software upgrades, ramping enhancements and other innovative improvements among those measures eligible for incentives, because these improvements in fact are part of the transmission system and are critical to its efficient and reliable operation. Priority should be given to those investments which are breaking new ground. For example, thanks to Department of Energy cost-sharing incentives ($50 million+), deployment of synchrophasors has become widespread in the Western Interconnection. Unfortunately, although utility efforts to use the high quality synchrophasor data in real-time grid operations has lagged badly, the Commission could spur these efforts by examining why utilities (and reliability coordinators) are not acquiring real-time grid management tools that use real-time synchrophasor data. Operation of the system with increased real-time awareness improves reliability and improves the efficiency of the existing transmission system. Relatedly, reliability standards and practices should be updated to require use of these tools.

Interregional Transmission Projects

Q44: 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 is aware of the problems with regional and interregional planning under Order No. 1000 that section 219's incentives cannot solve. Regional and interregional planning is often a misnomer in that regional planning entities often focus their analyses on meeting what are essentially local reliability needs, making only a passing effort at identifying meaningful expansions of the high-voltage interregional transmission network to facilitate flexible integration of low-cost power from remotely constrained renewable generators. For example, the WestConnect planning process often blocks need determinations for interregional transmission projects, and instead merely "rolls up" local reliability needs into a regional plan, which then allows it to assert that no new regional or interregional transmission is needed.[14]

Stakeholders, other than incumbent utilities, largely consider the current interregional coordination process in the Western Interconnection to be a failure. Order No. 1000 interregional planning coordination in the western interconnection involves a single annual meeting. Current financial incentives do not address this problem. They are both too much and not enough – too much in that they add new costs, and not enough in that additional financial incentives do not solve the primary barriers to regional and interregional transmission development. The result is that the lack of interregional planning is contributing to rates that are not just and reasonable and that unnecessarily add costs to both wholesale and retail customers.

---

[14] See WestConnect Regional Transmission Planning, *2016-17 Planning Cycle; Regional Transmission Needs Assessment Report* (2017), https://doc.westconnect.com/Documents.aspx?NID=17749&dl=1.

Since planning among two or more regions with different standards and processes is especially challenging, we encourage the Commission to focus its initial efforts on interregional planning reforms.

Correcting weaknesses in interregional planning is sufficiently urgent enough to warrant a Commission proceeding to rectify them. Requiring meaningful interregional planning and cost allocation reflecting all benefits should be the focal point of these reforms. As we and others have expressed in other comments to the Commission, solutions should include:

1. Remove the "triple hurdle" approval process for interregional projects.
2. Establish cost allocation standards recognizing the full range of regional and interregional benefits of transmission, including effects on delivered energy costs, allocating the requisite portion of those costs that reflect regional benefits to all customers in the region, regardless of their utility's or their own contractual status with the new project. For example, analysis done by NREL in its "Interconnection Seams Study" study forecasts highly favorable cost-benefit outcomes from a high-voltage DC overlay creating a truly national transmission system, especially when accounting for benefits such as access to remote resources, access to resources with favorable load shapes that reduce costs to optimize generation and load balance, and reducing greenhouse gas emissions. For a more complete list of transmission benefits, see our answer to Question 5.
3. Require Order 1000 planning groups to provide historical information on transmission path flows so that developers, regulators and the public understand where new transfer capacity is needed and where existing transfer capacity is underutilized.

4. Assess the benefits of RTOs, ISOs, and other Order 1000 planning regions joining in a national planning authority to review and consider jointly in a cooperative single planning and cost allocation process, subject to direct Commission approval, proposals to provide high-voltage links among the three interconnections.

Unlocking Locationally Constrained Resources

Q47: Should the Commission use incentives to encourage the development of transmission projects that will facilitate the interconnection of large amounts of resources?

No. Monetary incentives will not help to address this question. Instead we recommend the nonmonetary measures we suggest regarding reform of Order 1000 planning and cost allocation. Many remote renewable energy development zones have vast resources requiring significant amounts of transmission services, the connection of which to the electrical system confer valuable operational benefits. An example of the advantages of proactively building transmission to such areas is the Texas Competitive Renewable Energy Zone (CREZ) process in which transmission was prospectively built to zones of high resource potential. Texas is on its way to integrating nearly 30 GW of wind resources with decreasing amounts of curtailment as the state's resource mix undergoes a massive transformation.[15] Annual electricity production cost savings (are) $1.7 billion per year plus another $5 billion in incremental economic development. With a service life of 30 to 50 years, the benefits of the CREZ lines will return their construction cost of $7 billion many times over[16]. Access to these resources

[15] For Americans for a Clean Energy Grid's discussion of the accomplishments of the Texas CREZ experience, see *Texas as a National Model for Bringing Clean Energy to the Grid*, cleanenergygrid.org, https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/ (last visited June 26, 2019).

[16] *Id.*

will decrease consumer costs as well as facilitating operational efficiencies across distant parts of the system. Large scale integration of these abundant resources also has been shown in several studies (NREL *Renewable Electricity Futures* [17], The Wind Diversity Enhancement of Wyoming/California Wind Energy Projects: Phase 2 study,[18] and the National Renewable Energy Laboratory's *Interconnection Seams Study*, which looked at the costs and benefits of linking the two largest interconnections – East and West – with three different transmission connection or overlay design scenarios.[19] The success of this initiative was obtained through unified regional planning and cost allocation not financial incentives.

Q49: 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 geographic area?

The queue is a significant but not the only indicator of potential. Other indicators include the resource capacity of the area in question, the resource capacity factor, the generation's load shape in comparison to expected load centers' demand profiles and renewable energy resource generation shapes.

Order No. 1000 Transmission Projects

Q54: 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

---

[17] *See generally* Michael Milligan et al., Nat'l Renewable Energy Lab. (NREL), NREL/TP-6A20-52409-4, *Renewable Electricity Futures Study, Vol. 4: Bulk Electric Power Systems: Operations and Transmission Planning* (2012).

[18] Jonathan Naughton, University of Wyoming Wind Energy Research Center, *The Wind Diversity Enhancement of Wyoming/California Wind Energy Projects: Phase 2*, 28 (2015).

[19] The U.S. Department of Energy has not published the study yet, but it was presented in detail at Iowa State University at the Trans-Grid X Symposium by NREL's Aaron Bloom. Aaron Bloom, Nat'l Renewable Energy Lab. (NREL), Presentation at TransGrid-X Symposium: Interconnections Seam Study (July 26, 2018), https://cleanenergygrid.org/wp-content/uploads/2018/08/NREL-seams-transgridx-2018.pdf (last visited June 26, 2019).

requests for such incentives under section 205, or should the Commission consider requests for such incentives for non-incumbent transmission owners under section 219?

Financial incentives are not attractive to independent developers because they increase project costs and affect project financing. As we explain elsewhere in these comments, a more effective approach would be to reform regional and interregional planning to account for the full range of transmission benefits, and not just limit analysis to congestion relief and rolling up local reliability needs. Understanding how transmission would benefit larger areas of the system is critically important for a fair consideration of these lines. Financial incentives do little to rectify this situation.

The Commission should also strive to increase the scope of competitive bidding processes for new transmission facilities to increase competition between incumbent and non-incumbent transmission providers.

Transmission Projects in Non-RTO/ISO Regions

Q55: Are there factors that discourage developers of transmission projects in non-RTO/ISO regions from seeking incentives?

Yes, often in non-RTO/ISO regions investors in transmission projects are unable to capture all the benefits of their investment because many of the benefits from the investment flow to owners of other transmission lines. This free rider situation discourages investment in transmission. For example, the deployment of new technologies to block overloads on an underlying lower voltage system can enable significant increases in transfer capacity on the existing very high voltage grid. However, a local utility making such investments will not be able to acquire the rights to the increase in transfer capacity on the very high voltage that their investments have enabled. The mismatch between those potentially making transmission investment and those reaping the benefits of such investments discourages even the evaluation of possible transmission improvements.

Q56: What, if any, additional types of incentives could appropriately encourage the development of transmission in non-RTO/ISO regions?

As we explained in our answer to Question 63, a valuable incentive involves encouraging the movement to larger regional markets and balancing area consolidation in non-RTO areas.

RTO/ISO Participation

Q63: If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?

The RTO Participation Adder is no longer serving its intended purpose. Instead, to encourage the development of more efficient regional markets – the foundation of which is a single large, well-interconnected market region – the Commission should consider reforming the current RTO Participation Adder into one that rewards participation in regional systems that have some but not all the attributes of RTOs.

The Commission's justification for the current RTO Participation Adder is to recognize the benefits of RTOs to customers,[20] and to encourage the continuing involvement in an RTO.[21] However, based on the adders approved by the Commission since the 2012 incentives policy statement, it is unlikely that they are materially affecting a company's decision to either participate in an RTO or (even less likely) join another RTO. The Commission has granted approximately 22 RTO Participation Adders for specific projects since 2012 with an estimated value of $34 million. **See Appendix A of these Comments**. While a significant amount of money, it is small in comparison – less than 0.65% -- to the project value of approximately

[20] Promoting Transmission Investment through Pricing Reform, Order 679, FERC Stats. & Regs. at 158 (2006).

[21] *Pacific Gas and Electric*, 141 FERC ¶ 61,168 at 8 (2014). *See also* Order 679, *supra* note 20 at 167 (stating that the Commission will grant the RTO Participation Adder to organizations that have previously joined an RTO so as not to "create perverse incentives for an entity to actually leave Transmission Organizations and then join another one").

$5.228 billion. More important, it is highly unlikely that the incentive was necessary to incent large companies to remain in CAISO or other RTOs. This existing incentive should be discontinued.

Non-RTO areas have problems related to system balkanization and balancing area conflicts. Pancaked transmission charges and false congestion due to bilateral transmission access contracts confound the cost-effective integration of variable renewable generation across a wide geographical area. At the same time, Order No. 1000 has largely failed at motivating interregional transmission development between and among regional planning authorities (e.g., WestConnect, NTTG)

In the West, for example, there is strong interest in the need for better grid coordination and the creation and expansion of partial regional market platforms such as the Western Energy Imbalance Market (EIM), launched by the CAISO in 2014. The EIM has been an overwhelming success, generating more than $650 million[22] for participants since its inception, and attracting participation from most western states, and the number of EIM entities continues to grow.

The EIM's success has led to the consideration of additional market products such as CAISO Day-Ahead Market Enhancements (DAME) and extending these day-ahead market enhancements to EIM participants (also known by the acronym EDAM). EDAM would permit regional generators to bid surplus power into the next day's market for a specified hour, especially benefitting hydroelectric producers who can use this tool to provide flexibility services in support of variable renewable generators. These interim steps to efficient regional

[22] For a description of Western EIM benefits by participant, see *Western Energy Imbalance Market - Benefits*, westerneim.com, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx (last visited June 26, 2019).

markets are valuable trust builders for a region just becoming accustomed to closer market coordination.

All of this background is to support the idea that participants joining such new regional markets such as the EIM should qualify for a financial inducement like the RTO membership incentive to motivate new transmission to complement and support regional market enhancements. This incentive can increase as progress continues toward forming a regional RTO.

An incentive might be useful to a company's bottom line by offsetting the costs of relinquishing transmission rights. Currently, EIM participants have no transmission access charges because they agreed to use transmission paid for but unused within the hour for real time transactions. This is not the case for a day-ahead market product that would require both unit and transmission commitment in the hour. Transmission rights will have to be identified and compensated in a cost-effective way for such a market to work. A market participation incentive could offset at least some of the perceived costs of relinquishing transmission rights, more closely approximating the operation of an RTO. As benefits accrue, market participants – both publicly and investor owned – could be expected to become more comfortable with full regional market development, potentially leading to a much-needed western regional market, as was experienced in the evolution of the Southwest Power Pool.[23]

[23] In 2007, SPP began operating its real-time Energy Imbalance Service (EIS) market. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards. In March 2014, SPP implemented its Integrated Marketplace, which that includes a day-ahead energy market, a real-time energy market, and an operating reserve market. *See Electric Power Markets: Southwest Power Pool*, ferc.gov, https://www.ferc.gov/market-oversight/mkt-electric/spp.asp (last visited June 26, 2019).

This incentive would be particularly useful in non-RTO areas, such as the western interconnection. However, to support the objective of more efficient use of the grid, this incentive should only be extended to those western EDAM participants who allow dispatch over their wires up to reliability limits (e.g., System Operating Limits, Interconnection Reliability Operating Limits) and do not limit use the transmission system for market dispatch by factors other than grid reliability (e.g., contract path limits, TTC/ATC).

Advanced Technology

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

PIOs believe that advanced technologies are often individually inexpensive and as such individually are not attractive to utilities seeking cost recovery from state commissions. Additionally, often the deployment of advanced technologies provides benefits to parties beyond those making the investment. There has been no effective way for investors to capture such free rider benefits. Therefore, we believe that performance-based incentives compensated through shared savings provides a better option. See also answer to Question 69.

Q68: Do NERC reliability standards affect the willingness of transmission developers to enhance existing transmission facilities by deploying new technologies because of concerns these technologies may increase the risk of standards violations?

To the extent that this is the perception, the Commission should require NERC to address these concerns and find ways to motivate and encourage innovation and use of new technologies. This is particularly true for new technologies that increase the level of available transmission capacity for transmission facilities or the overall system. Concerns about NERC compliance risk, whether due to an argument about new technology risk or resistance to embracing newer technologies, should not be accepted as an excuse to avoid making changes that increase the available transmission capacity, particularly for new technologies that can do so while minimizing additional capital costs and implementation time as compared with adding conventional transmission assets.

Q69: Are there any types of transmission incentives that could better encourage deployment of new technologies? If so, please describe them.

Within any framework of purely financial incentives, we encourage the Commission to focus on motivating advanced transmission technologies to optimize the capacity, management, and control of energy on the grid, especially the vast existing network. Phase angle regulators, application of dynamic line rating (DLR), storage-as-transmission, power flow control, high voltage direct current (HVDC) hardware, local generation such as solar to relieve congestion and other solutions will be necessary to reliably and efficiently maximize the grid values of high levels of variable renewable energy resources, demand management, and other considerations.

Many of these technologies are inexpensive compared to new lines and providing significant additional transmission capabilities. For example, one high-value solution to increasing line capacity is DLR, which assesses available line capacity based on changing weather and other conditions. A large transmission line's capacity can increase significantly when ambient temperatures are cooler or wind speeds are higher. Yet most of the time utilities rate their lines based on worst-case on worst-case weather conditions. Windy conditions, especially in combination with lower ambient temperatures, can increase line capacity by 40% or more.[24] [25] DLR thus can allow the lines to accommodate more energy without overheating, which means

[24] Jake Gentle et al., *Increasing Transmission Capacities by Dynamic Line Rating Based on CFD*, https://watttransmission.files.wordpress.com/2017/11/2015_awea_dlr_validation_final.pdf (last visited June 26, 2019).

[25] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, *Dynamic Line Rating Systems for Transmission Lines: Topical Report* (2014), https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf.

that more low-cost power can be delivered to customers. DLR can support the need to make faster operational decisions based on more rapidly changing conditions, especially as the nature and mix of generation sources changes.

Current incentives are inadequate to encourage the use of these technologies by utilities and transmission operators.[26] A June 2019 Department of Energy Report to Congress on DLR and other advanced transmission technologies found that:

> The U.S. currently lags behind other countries in the deployment of some advanced transmission technologies, such as DLR. One of the variables is the difference in regulatory environments; the U.S. provides transmission owners little incentive to deliver more power over existing lines or to reduce transmission congestion.[27]

More generally, within any framework of a framework of purely financial incentives, we encourage the Commission to focus on motivating advanced transmission and technologies to optimize the capacity, management, and control of energy on the grid. Many of these technologies are so inexpensive that by themselves, current incentives are inadequate to encourage their use by utilities and transmission operators. One solution would be to bundle a portfolio of cost-effective non-wires measures together to qualify for a combined incentive, and to focus the incentive's purpose not on expansion but on operational efficiencies that better use

[26] For a recent analysis and proposal of how to integrate these resources, see Rob Gramlich, WATT Coalition filing in FERC docket PL 19-3, and Rob Gramlich, Working for Advanced Transmission Technologies Coalition, *Bringing the Grid to Life: White Paper on the Benefits to Consumers of Transmission Management Technologies* (2018) https://watttransmission.files.wordpress.com/2018/03/watt-living-grid-white-paper.pdf.

[27] U.S. Department of Energy, *Dynamic Line Rating* at iv (June 2019).

existing transmission infrastructure, increase transfer capacity, alleviate congestion and enhance reliability.[28]

We support the WATT Coalition proposal for a shared-savings approach to provide transmission owners with an incentive in cases where consumers would benefit from quantifiable congestion reduction.[29] This proposal draws on elements from policies established in Australia and Great Britain (RIIO). Critically, in the Australian model, receipt of the incentive is based on those projects that satisfy a "Service Target Performance Incentive." The approach has successfully deployed several new technology projects on both existing and new lines.[30] Examples of these technologies and management approaches include: dynamic line ratings, power flow control, storage-as-transmission, and topology optimization among others. The projects range in size from $34,000 to $3.1 million (US dollars).[31] Australia's program is administratively workable because the grid operator and regulator approve a bundle of small projects together. This could present an advantage over RTOs performing a study on every small deployment.

Non-ROE Transmission Incentives

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

---

[28] *Id*.

[29] Ofgem, Great Britain's gas and electricity regulator, has adopted similar performance-based requirements. *See* Melissa Whited et al., Western Interstate Energy Board, *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (2015), https://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

[30] Australian Energy Regulator, *TransGrid Transmission Determination 2015-16 to 2017-18: Attachment 11 – Service Target Performance Incentive Scheme* 14 – 15 (2015), https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20TransGrid%20transmission%20determination%20-%20Attachment%2011%20-%20service%20target%20performance%20incentive%20scheme%20-%20April%202015%20fixed.pdf.

[31] *Id.*

Q71: Should the costs of unsuccessful Order No. 1000 proposals be recoverable through regulatory asset and deferred pre-commercial cost recovery incentives? If so, what costs are appropriate for recovery?

No. the Commission should not subsidize unsuccessful projects and the cost exposure to such project sponsors is modest.

Mechanics and Implementation
Duration of Incentives

Q85: 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?

Whether to withdraw or modify an incentive will depend on project-specific circumstances, including considerations such as changes to the project's scope, size, or timing. Since retracting an awarded incentive likely would inject financial uncertainty in project finance decisions, FERC should carefully define the circumstances under which withdrawal or modification is appropriate.

Q86: Should there be a process of measurement and verification (or audit) to determine if the expected benefits accrued to consumers?

As noted in our responses to Questions 6, 7, and 10, the Commission should evaluate the value of performance-based incentives forecast as an *ex ante* incentive in an *ex post* evaluation.

Q87: If so, how should measurement and verification take place and over what time period?

The duration of benefit analysis is difficult to determine as benefits accrue over long time frames and incentives are valuable only prospectively. The Commission should explore further the evaluation time frames for varying types of incentives. This will at least establish some certainty on the part of the applicants about what their exposure to a negative determination would be and the Commission should provide an avenue of appeal through which applicants may challenge these evaluations and substitute additional analysis. Such a process will increasingly fine tune the scale and evaluation duration of performance-based standards without delaying the provision of an incentive to a worthy project. Finally, by scaling the incentive to a portion of the potential shared savings the Commission would be incenting efficiency over gold plating.

Q88: Should the Commission consider eliminating an incentive if the project fails to realize its anticipated benefits?

No. Such an action would nearly assure that most developers would decline the incentive, since it would amount to a significant project risk. It contradicts the concept of a risk incentive.

Q89: Should there be reporting on projects' expected benefits compared to results, and over what time period?

This is difficult to determine and may differ depending on the measures being incented and the type of incentive offered. Benefits may be spread out over decades and could be subject to change based on factors way beyond the transmission developer's control.

One approach would be to compare actual results with expected benefits to improve the process for estimating benefits over time. The Commission should recognize there will almost certainly be large discrepancies between forecasted and actual benefits because of changes in technology and costs (for example solar and batteries).

Metrics for Evaluating the Effectiveness of Incentives

Q98: What metrics should the Commission use in measuring the effectiveness of incentives, e.g., if certain milestones are reached or only if a transmission project is built and energized?

Metrics should clearly be related to and quantify progress toward the expected outcomes. For example: What were the line miles planned versus line miles built? Did the time it took to build the asset match that which was anticipated? Did the cost per mile budgeted approximate the cost per mile as built? The Commission could require reporting of the measured progress by each entity so that their performance can be compared with each other.

In Great Britain, Ofgem's performance-based framework for setting network price controls (Revenue = Incentives + Innovation + Outputs (RIIO)), and experience in Massachusetts with a "dashboard" reporting format shows evidence that performance reporting provides incentive for improved performance. Once performance can be defined well, measured adequately, and compared, then the Commission could consider adding financial incentives.[32]

Q100: Should the Commission require that incentive recipients provide additional data through Form FERC-730? If so, what additional information should be provided?

Yes. Current Form 730s are short and provide very little information. It should require the information in Question 101 below, plus more information itemizing the project costs, the received or awarded benefits and incentives in dollars, and detailed progress updates. In addition, the Commission should create a complete tracking system to provide the type of information we include in Appendix A to these Comments, with all the required information.

Q101: For each transmission project, should the Commission require additional data such as the primary driver of each transmission project (e.g., reliability needs) and the risks entailed in its development (e.g., number of permits required, siting challenges)?

Yes. Improved reporting on transmission project needs, status, and cost tracking is necessary to improve transparency of transmission planning and costs. Currently little data exists that is reported consistently across regions, both for projects that go through the full regional planning process as well as the many locally-planned projects that are not subject to the full regional planning process.

Q102: If a transmission project is abandoned, should the Commission require additional data such as the reasons that it failed (e.g., lack of financing, inability to obtain permits, the need for the transmission project did not materialize or was addressed through other means)?

[32] *See* Whited et al., *supra* note 29 (although written for state regulators, this handbook's concepts are equally relevant for the Commission).

Yes. These data will be important to help evaluate future project proposals in similar circumstances.

Q103: Should the information on annual transmission spending associated with projects that received transmission incentives be broken down by transmission project?

Yes; it is a reasonable approach to understanding the effectiveness of some incentives.

Q104: How burdensome would such information requirements be? To ensure that any reporting is not unduly burdensome, should the Commission adopt some type of reporting threshold, such as a voltage, mileage, or dollar threshold, to limit the transmission projects on which it collects information?

Completing the forms is a reasonable and low-cost expense in return for the value of hundreds of thousands or millions of dollars in incentives. All incentives should be comprehensively reported annually in a user-friendly data format, and capable of downloading in comma-separated values.

Conclusion

The current electrical system is changing dramatically. New variable renewable generation resources with different attributes than those that have fed the legacy system are emerging as major sources of American energy. These variable renewable resources lower the cost of power for consumers, geographically balance the grid, and can provide essential ancillary services to the system. This evolving system holds great promise for creating a lower cost, more flexible and resilient grid of the future. The keys to capturing these myriad benefits are transmission expansion to remote areas rich in renewable energy, grid upgrades, system modernization and the introduction of new technologies. Current financial incentives have not succeeded in significantly expanding transmission expansion on a national level. Both RTO and non-RTO planning regions have fallen short by failing to identify and encourage interstate and interregional transmission. Current incentives also do not encourage the use of technologies that improve the more efficient use of existing transmission infrastructure and rights-of-way. New approaches to incentives, including performance-based incentives and shared savings structures, and reforms to the RTO Participation Adder, are needed to capitalize and accelerate the introduction of new technologies. Furthermore, non-monetary policy incentives, such as reforming regional and interregional planning and cost allocation under Order No. 1000, remain critical gaps, and so we encourage the Commission to move forward with its pending Order No. 1000 inquiry and expand it to include the issues addressed in these Comments.

Respectfully submitted,

Deborah Donovan
Massachusetts Director & Senior Policy Advocate
Acadia Center
31 Milk Street, Suite 501
Boston, MA 02109-5128
(617) 742-0054
ddonovan@acadiacenter.org

Carl Zichella
Director of Western Transmission
Climate and Clean Energy/Nature Programs
Natural Resources Defense Council
111 Sutter Street, 20th Floor
San Francisco, CA 94104
(415) 875-6119
czichella@nrdc.org

Ric O'Connell
Executive Director
GridLab
426 17th Street, Suite 700
Oakland, CA 94612
(415) 305-3235
ric@gridlab.org

John N. Moore
Senior Attorney and Director
Sustainable FERC Project
20 North Wacker Drive, Suite 1600
Chicago, IL 60606
(312) 651-7927
Moore.fercproject@gmail.com

Kate Maracas
Managing Director, Western Grid Group
7730 78th Loop NW
Olympia, WA 98502
(360) 688-1105
kate@westerngrid.net

CERTIFICATE OF SERVICE

I hereby certify on this 26th day of June 2019, I served a copy of the foregoing upon each person designated on the Official Service List for this proceeding.

/s/ John N. Moore
John N. Moore

APPENDIX A
FERC-Approved RTO Participation Incentives

2018

Docket	Company	Project Cost	Value of Adder
ER18-1159-000	MISO o/b/o Pioneer	$173.5 million	$867,500
ER18-125-001	NextEra Energy	$181 million	$905,000

2017

Docket	Company	Project Cost	Value of Adder
ER17-419-000	PJM Interconnection	$197m	$985,000
EL17-52-000	Republic Transmission	$49.8m	$249,000
EL16-47-000	PG&E	$1.76 billion	$8,800,000

2016

Docket	Company	Project Cost	Value of Adder
ER16-453-000 ER16-453-001	PJM o/b/o Northeast Transmission Development	$146 million	$730,000
ER15-2239-000 ER15-2239-001	NextEra Energy West	$42.288m $24.539m	$211,440 $122,695
EL16-68-000	DesertLink	$144 million (from Project Sponsor Selection Report)	$720,000

2015

Docket	Company	Project Cost	Value of Adder
ER15-572-000	NYISO o/b/o NY Transmission owners	$1.02 billion $ 98.3 million $66 million $121 million $262 million	$5,100,000 $491,500 $330,000 $605,000 $1,310,000
ER15-2114-000	PJM o/b/o Transource WV	$59.5 million	$297,500

APPENDIX A
FERC-Approved RTO Participation Incentives

ER15-1682-000	TransCanyon DCR	$300 million	$1,500,000

2014

Docket	Company	Project Cost	Value of Adder
ER14-1661-000	MidAmerican Transco Central CA Transco	$78.5m	$392,500
EL14-51-000	PG&E	$78.5m	$392,500

2012

Docket	Company	Project Cost	Value of Adder
ER12-2554-000	Transource Missouri	$64.8 million $380 million	$324,000 $1,900,000
ER12-2701-000	PG&E	$782.8 million in capital projects in 2012 $836.9 million in capital projects in 2013	$3,914,000 $4,184,500

FERC Orders that Grant RTO Adders but no Specified Projects

2017

Docket	Company	Company Formation
ER16-2716-000 ER16-2716-001	NextEra Energy MidAtlantic	PJM Order 1000
ER16-2717-000 ER16-2717-001	NextEra Energy Midwest	MISO Order 1000
ER16-2719-000 ER16-2719-001 ER16-2719-002	NextEra Energy New York	NYISO Order 1000
ER16-2720-000 ER16-2720-001	NextEra Energy Southwest	SPP Order 1000
ER17-706-000	GridLiance West	CAISO Order 1000

APPENDIX A

FERC-Approved RTO Participation Incentives

2015

Docket	Company	Company Formation
ER15-2594-000	South Central MCN (now known as GridLiance High Plains)	SPP Order 1000
ER15-2237-000	Kanstar Transmission	SPP Order 1000
ER15-2236-000	Midwest Power Transmission Arkansas	MISO Order 1000
ER15-1809-000	ATX Southwest	SPP Order 1000
ER15-2114-000	PJM o/b/o Transource WV	$59.5 million
ER15-1682-000	TransCanyon DCR	$300 million
ER15-958-000	Transource Kansas	SPP Order 1000

2014

Docket	Company	Company Formation
ER14-2751-000	Xcel Energy Southwest	Southwest Power Pool

Document Content(s)