UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL COMMENTS OF THE
AMERICAN WIND ENERGY ASSOCIATION

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") March 28, 2019 Notice of Inquiry ("NOI") in the above-referenced proceeding, the American Wind Energy Association ("AWEA")[1] submits the following initial comments on the Commission's scope and implementation of its electric transmission incentives regulations and policy. Much of this nation's existing transmission infrastructure is inefficient and balkanized, falling short of ensuring reliability/resilience, lowering costs for customers and meeting public policy goals. Thus, it is critical for the Commission to ensure a regulatory environment that incents transmission infrastructure—aligning it with the present and future needs of the grid.

While we appreciate the Commission opening an examination of its transmission incentive policies, and believe that incentives have a role to play in encouraging the deployment of capital and accelerating infrastructure development, they represent only the tip of the iceberg with respect to the country's transmission policies that need to be carefully scrutinized if the

[1] AWEA is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA's more than 1,000 member companies include wind turbine manufacturers, component suppliers, project developers, project owners and operators, financiers, researchers, utilities, marketers, customers, and others.

Commission truly wants to incentivize badly-needed new transmission infrastructure.[2] Indeed, it is more likely that shortcomings in the Commission-approved transmission planning and cost allocation policies are providing *disincentives* to meaningful investment, and that financial incentives alone cannot counteract these issues. Accordingly, we encourage the Commission to examine more broadly the barriers to the continuing development and optimization of the bulk power system.

As detailed below, there are specific areas in which AWEA believes enhanced incentives by themselves, or coupled with broader reforms, can potentially improve the transmission system, particularly regarding more effective use of existing transmission assets. AWEA encourages the Commission, consistent with these comments, to undertake a rulemaking to address these issues where incentives can incrementally improve transmission infrastructure, and to evaluate transmission policy more broadly in areas where incentives alone may be insufficient.

I. INTRODUCTION

AWEA agrees with the Commission's decision to examine and question whether transmission infrastructure can be catalyzed by looking at and considering reforms to the current incentives framework. Additional incentives can theoretically serve to incentivize marginal transmission investments in building new transmission lines forward (i.e., investments that might not be viable but for one or more financial inducements). However, AWEA notes that potential transmission investments are not typically sidelined by inadequate rates of return. Rather, in most cases, substantial private capital is already available for new transmission development, even at current rates of return, and it is other barriers that stand in the way of the projects.

[2] *See*, *e.g*. Russell Gold, *Building the Wind Turbines Was Easy, the Hard Part Was Plugging Them In*, Wall Street Journal (June 22,2019), https://www.wsj.com/articles/building-the-wind-turbines-was-easy-the-hard-part-was-plugging-them-in-11561176010.

Therefore, even at their most efficacious, increasing or altering incentive rates will not fully unlock much-needed transmission investment on their own, particularly for new transmission lines.

In most cases, the impediment to transmission development is the complex and uncertain process for transmission permitting, planning, and cost allocation. For example, very few significant regional or interregional transmission projects have been approved in the last several years (even with the Order No. 1000 reforms)—expansion planning has largely been focused on meeting local reliability needs. It does not appear that financial incentives of the type contemplated in this NOI are even capable of stimulating significant new regional and interregional transmission investment, due to the fact that the planning and cost allocation processes are the main hurdles. Therefore, AWEA urges the Commission to consider transmission reform policies holistically, as shifting financial incentives in isolation would simply increase the price tag for transmission—without accelerating development or enhancing competition. Simply put, short of reform in the areas of 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 the project and make it harder to get over these hurdles.

Before providing our recommendations pertaining to this inquiry, AWEA believes it is, therefore, worth briefly examining non-financial actions that could address and resolve these barriers more effectively than an incentives framework. Many of the current transmission hurdles and their fixes are well known; but they are worth repeating, as they are the key reforms *in any* evaluation of transmission policy, incentive-based or otherwise:

- Transmission planning and cost allocation should consider the broad range of benefits each proposed project provides (economic, reliability and public policy) in an integrated fashion.[3]
- Transmission providers should meaningfully plan for projects that advance public policy requirements on an equal footing with economic and reliability projects.[4]
- Interregional planning requirements should be synchronized across regions and within the regional planning processes.[5]
- Planning should be probabilistic and proactive to address realistic long-term scenarios.[6]
- Transmission planning and generation interconnection processes should be harmonized.[7]

The NOI correctly identifies several subjects where Commission-led incentive reform could significantly improve access to low-cost resources while improving reliability, primarily incentives related to improving the existing transmission system.[8] In addition, there are other

[3] At present, regions can categorize projects into a single bucket, and evaluate benefits narrowly. In fact, most (if not all) transmission projects do provide a range of benefits, both on today's grid and throughout their lifespan. Accordingly, benefits determinations should fully consider all projected project benefits.

[4] Several regions consider economic and reliability transmission projects sequentially, with public policy projects considered later (although this is by no means universal). As noted above, benefits should be considered holistically, and projects that can simultaneously address more than one category – including public policy, on a coequal basis - should be prioritized.

[5] Order No. 1000 introduced formal structure into interregional transmission planning. However, in practice not a single interregional line has actually been built under the Order No. 1000 framework. In large part, this is due to the "triple hurdle," in which interregional lines have to secure two separate regional approvals as well as an interregional approval. There is no present requirement that any of these processes use shared assumptions, benefits assessments, or modeling. The Commission should consider every option at its disposal to ensure that regions and interregional processes are harmonized to the greatest extent possible. This will ensure that projects are consistently evaluated throughout the planning process while reducing cumbersome red tape and accelerating the load and resource diversity benefits of interregional transmission.

[6] Load growth, resource types and locations, and policy considerations are not static, and many states are engaging in significant energy commitments through statutory reforms. Transmission planning should be optimized so that projects that will reliably and economically support both today's grid and the grid of the future will move forward.

[7] At present, transmission planning and generation interconnection processes move on separate tracks. This can lead to significant generation queues that are out of sync with planned transmission; in turn, this can lead to significant upgrade costs for interconnecting generators. Identifying areas where transmission will be needed and deploying cost-effective transmission expansion accordingly can allow customers to access cheaper power more quickly and enhance system reliability.

[8] Grid operators have noted that transmission expansion is integrally tied to improving system resilience *See, e.g., Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7, Comments of New York Indep. Sys. Operator, (Mar. 9, 2018) at 4 ("Resiliency that goes beyond traditional measurements of reliability includes measures that could assist in more expeditious recovery from disruptive events. *In this way, resiliency is closely linked to the importance of maintaining and expanding interregional interconnections, the building out of a robust transmission system*, and the evaluation of additional resources, resource capabilities, and services in critical areas, such as energy storage, that could support rapid recovery from system disturbances.") (emphasis added), Comments of Southwest Power Pool, Inc. (Mar. 9, 2018) at 4 ("The construction of new transmission facilities pursuant to modern design standards enhance the robustness of the system.").

areas, such as with respect to interregional lines and access to locationally constrained resources, that incentives, if coupled with the broader reforms noted above, could provide support for the build out of new transmission lines. In other words, additional reforms would largely be needed to make the incentives truly effective for moving new transmission projects forward.

Below is a list of areas in which incentive reform, particularly coupled with further reforms, could provide incremental benefits for improving the current state of transmission infrastructure:

- A benefits-centric incentives framework as the norm, with potential use of risk-based incentives in limited circumstances.
- Performance-based and shared savings incentives for technological enhancements to existing transmission infrastructure.
- Incentive-seeking parties should be able to use a range of benefits, including but not limited to:
  - Providing economic benefits resulting from increased transfer capability between regions or balancing authorities;
  - Producing reductions in curtailment frequency or scale, where curtailed resources would reduce the cost of delivered power;
  - Enabling more efficient use of existing wires, towers and rights-of-way;
  - Forward-looking upgrades or development that will reduce or eliminate anticipated future congestion;
  - Satisfying federal and/or state policy requirements, such as meeting a renewable portfolio standard;
  - Facilitating the development of remotely constrained low-cost resources that might otherwise be stranded;
  - Providing access to complementary renewable energy generation;
  - Reducing the need for duplicative balancing or flexible generation within a market footprint;
  - Supporting interregional projects; and
  - Providing reliability and resiliency to the system that would otherwise not be present.

Finally, AWEA notes that the Commission should support financial incentives only in those instances where they are likely to *actually* incent new projects or encourage expansion of existing assets – or, put differently, where a project would be unlikely (or significantly less likely) to move forward without it. Any incentives the Commission adopts should also reflect cost causation principles, with benefits commensurate with costs.

II. BACKGROUND

Section 1241 of the Energy Policy Act of 2005 added Section 219 to the Federal Power Act.[9] The legislative history indicates that Section 1241 "directs FERC to issue rules on transmission pricing policies that provide a return on equity that attracts capital for investment in grid improvements and advanced transmission technologies."[10] The statute states that Congress intended FERC to promote capital investment to all transmission facilities, regardless of ownership, to provide a ROE attracting new investment, and to encourage steps to increase the capacity and efficiency of existing transmission facilities and improve those facilities' operations.

The Commission then issued Order No. 679[11] in 2006, with the stated aims of "bolster[ing] investment in the nation's aging transmission infrastructure, and … promot[ing] electric power reliability and lower[ing] costs for consumers, by reducing transmission congestion."[12] Order No. 679 introduced an incentives framework, in which incentives would "be applied in a manner that is rationally tailored to the risks and challenges faced in constructing new transmission… [E]ach applicant must demonstrate that there is a nexus between the incentive sought and the investment being made."[13] In 2012, the Commission evaluated its experience with incentives under Order No. 679, and issued a policy statement refining its criteria, but continuing the use of the incentive/risk "nexus" framework.[14]

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[9] 16 USC 824s.
[10] S. Rep. No. 109-78 at 50 (2005), https://www.congress.gov/109/crpt/srpt78/CRPT-109srpt78.pdf.
[11] Promoting Transmission Investment through Pricing Reform, 116 FERC ¶ 61,057 (2006).
[12] FERC Press Release (Jul. 20, 2006), https://ferc.gov/media/news-releases/2006/2006-3/07-20-06-E-3.pdf.
[13] Order No. 679 at P26.
[14] Promoting Transmission Investment Through Pricing Reform, 141 FERC ¶ 61,129 (2012).

AMERICAN WIND ENERGY ASSOCIATION

III. COMMENTS AND RESPONSES TO SPECIFIC NOI QUESTIONS[15]

A. Incentives Framework

1. Incentives Based on Project Risks and Challenges

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

AWEA believes that the current risk-based framework has proven ineffective. The present requirement to show that a project faces specific risks or challenges is in tension with the statutory objectives of "promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce"[16] and "provid[ing] a return on equity that attracts new investment in transmission facilities."[17] This framework has not encouraged implementation of lower-risk projects, even where the projected benefits may be substantial, while the (nominally) available incentives have rarely helped to push riskier projects to completion.

Incentives should not necessarily be awarded solely based on either risks-and-challenges or on prospective benefits, but can and should incorporate both, as discussed below. AWEA believes a benefits-based framework is appropriate in most circumstances, but that the risks-and-challenges approach may be relevant only for certain types of incentives.

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

[15] AWEA does not attempt to respond to every question in the NOI. Additionally, AWEA generally supports the comments offered by the Public Interest Organizations ("PIOs") and the WATT Coalition, and incorporates parts of those comments herein.
[16] FPA 219(b)(1).
[17] FPA 219(b)(2).

for other reasons?

Incentives based only upon risks and challenges fail to account for the benefits derived from performance-based approaches, and tend to neglect lower-risk transmission investments. The Commission should instead emphasize and reward efficient solutions employing newer and innovative technologies. These solutions may better be rewarded through a shared savings mechanism (potentially including performance-based incentives) focusing on avoided costs of more expensive alternatives and the aggregation of system benefits. Ideally, an estimate of avoided costs for other transmission or system congestion solutions would be combined with an estimate of expected benefits using a broad analysis, and the benefits then be shared between the proposing utility or other market participant (receiving the incentive) and the customers who would benefit (receiving reliability and/or economic benefits).

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, but only where the evidence clearly supports an incentive. FERC correctly notes that the base ROE includes some degree of risk and challenge. Therefore, any incentives based on risks and challenges should 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 or interregional lines requiring multiple stages of planning, permitting, and approvals, as these aspects can diverge widely in both timing and the expectations for project applicants.

2. Incentives Based on Expected Project Benefits

Q4: 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 NOI offers two alternatives to the current risks-and-challenges framework – first, emphasizing project benefits "related to reliability and reductions in the cost of delivered power by reducing transmission congestion"[18] and incentives based on project characteristics (as a proxy for benefits).[19] AWEA supports a shift to a benefits-centric incentives framework as the norm. To implement such a framework, direct examination of expected benefits from proposed projects seeking an incentive is necessary. As noted below, the benefits assessment should be holistic rather than limited in scope.

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?

General principles should absolutely include a demonstration of the reduction of congestion costs. However, general principles should also go beyond congestion reduction and evaluate a broad range of benefits, including:

- Whether the project enables more efficient use of the existing transmission system, including wires, towers, rights-of-way, and substations or other bulk power system elements;
- Whether the project facilitates the development of location-constrained low-cost resources that might otherwise be stranded. Such resources would, in many cases, provide significant economic and reliability benefits to customers;
- Whether the project provides access to renewable balancing 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 or across balancing areas;
- Whether the project facilitates a public policy goal, such as meeting a carbon reduction standard or renewable portfolio standard adopted by a state or combination

[18] NOI at P16.
[19] NOI at P18.

of states. The Commission should presume that state policy goals will be met, and its evaluation should include economic benefits of transmission projects that are consistent with- and may be driven by - state policy attainment;[20] and

- Whether the project provides resiliency to the system it would not otherwise have.

Available evidence strongly suggests that transmission investment leads to significant benefits – often more than double its cost.[21] AWEA believes that the accounting of transmission benefits by the Brattle Group for WIRES provides an excellent basis for a holistic evaluation of benefits, including dispatch, reliability, market, and environmental benefits.[22]

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

Current incentives (basis points on ROE) add to the overall balance of project funding that must be financed, rendering them of little use to transmission development companies. Shifting to a benefits-based approach allows for performance incentives that enable entities sponsoring a proposed project to share the savings projected to be created by the proposed project. To be effective, benefits should be forecast on an *ex ante* basis to allow for certainty for the developers, and subsequently evaluated on an *ex post* basis. A benefits-based approach also rewards efficiency and innovation in transmission solutions and compensation models. For example, performance-based incentives could allow entities to share the savings projected to be

[20] This approach would be consistent with the Commission's stated approach toward state policies in Order No. 1000. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 at P203 (2011)("[T]he reforms adopted below are intended to ensure that the local and regional transmission planning processes support the development of more efficient or cost-effective transmission facilities to meet the transmission needs driven by Public Policy Requirements, which will help ensure that the rates, terms and conditions of jurisdictional service are just and reasonable.").

[21] *See* MISO MVP 2017 Triennial Review at 4 (Sept. 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf (benefit:cost ratio ranging from 2.2 – 3.4); SPP Value of Transmission Report at 5 (Jan. 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf (benefit:cost ratio of 3.5).

[22] *See* https://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf at p.v, Table ES-1 (listing eight categories, and numerous subcategories, of benefits).

created by the proposed project. Benefits should be forecast on an *ex ante* basis to allow for certainty for the developers and evaluated on an *ex post* basis. They should include the full range of prospective benefits from the proposed project, as discussed in the Brattle/WIRES report noted above.

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

As noted above, an *ex ante* forecast would provide the most useful incentive for developers and would encourage efficiency in terms of the selection and implementation of any transmission system improvement (including non-wires alternatives). An *ex post* evaluation may be useful to determine if the forecast was as accurate as could be reasonably expected, though transmission system benefits often accrue over extended time frames. This means that determining the period over which to evaluate the benefits is difficult, and may require a case-by-case (or at least project type-by-project type) approach.

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?

Here, the benefits level should be proportional to the project costs, established as a percentage of the total predicted costs. It also would be appropriate to allow an incentive for the benefit of avoided cost. For instance, the avoided cost of additional generation for balancing, or flexibility due to access to lower-cost but otherwise stranded generation with a complementary generation profile should be considered benefits that ensure reliability and reduce the cost of delivered power.

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, and the Commission and many utilities are obviously familiar with cost-benefit analysis in the context of transmission planning. AWEA reiterates that such an analysis should include a broad range of benefits.

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, as well as an *ex post* evaluation to compare forecast and actual benefits. This information should be used to evaluate future incentive requests, but retroactive reductions or pay-backs of benefits are likely to provide a disincentive for many projects.

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 – and will be considered in any future incentive application - will discourage over-estimates and reduce the likelihood of gold-plating.

3. 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?

A project's characteristics may be more easily measured than project benefits and system values, but since the characteristics ultimately support meeting the benefits, AWEA believes that 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, AWEA generally does not support using project characteristics as a basis for incentives. A limited incentive for interregional lines may be appropriate, but as noted in the Introduction, significant reform of the interregional planning process is vitally important in its own right. AWEA believes that a characteristic-based interregional incentive is unlikely to be effective in the absence of such reforms.

B. Incentive Objectives

1. 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?

Reliability-only benefits should be accounted for in a robust planning and cost allocation framework, and do not seem appropriate for a dedicated, standalone incentive. There has not been insufficient transmission to address reliability needs. The obligation to serve and roll the cost into transmission rate base and earn a rate of return, coupled with NERC compliance, has provided a sufficient incentive, and no new financial incentive is needed.

However, other categories of benefits that enhance system optimization (for instance, by improving access to lower-cost, locationally constrained resources, by improving access to resources with favorable generation profiles that increase system diversity, and reducing GHG emissions), virtually by definition enhance system reliability and *also* support meeting reliability standards. AWEA supports evaluating reliability benefits in the context of a broad benefits assessment in which numerous potential benefits are evaluated, as discussed above. This approach would help to prevent the piecemealing of reliability-only transmission investments, and maximize overall benefits by co-optimizing reliability and other benefits.

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

Grid services (including essential reliability services as a subset) should be procured through market mechanisms whenever possible, preferable co-optimized with the real time market (and also the day-ahead market when necessary). Improving transmission assets is an important part of the supporting essential reliability services. For example, when there is a choice between a costly long-term reliability must-run (RMR) contract and new or upgraded transmission, the best choice usually is the transmission asset. Reducing transmission constraints to allow *other* resources to deliver essential reliability services (and other grid services, including energy, reserves and flexibility) is already reflected in the transmission planning process. Whether incentives would help to stimulate that planning is a question FERC should explore further. If an incentive could demonstrably accelerate deployment of the transmission solution and reduce or eliminate the cost of inflexible options such as RMR or persistent redispatch of higher-cost generation, the Commission should seriously consider it. However, the assessment of the reliability need should include non-wires solutions, and FERC should exercise 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?

As noted above, we lack sufficient information to know whether enhanced financial incentives could meaningfully stimulate additional necessary transmission investment for essential reliability services, beyond the implicit incentives embedded within a planning process that already tends to favor reliability-based projects.

2. 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 projects warrant incentives both for reducing congestion and for connecting new resources to load. However, the Commission should require the applicant or relevant transmission provider to release a public assessment of current and historical levels of transmission utilization. This assessment would indicate why any new transfer capacity is needed, and why an incentive is necessary to stimulate the investment. 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. FERC should not offer incentives to fix "congestion" which has not been publicly documented. For that reason, should the Commission establish 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. If a non-utility entity seeks incentives for transmission investment, the Commission should eliminate barriers to access any necessary flow and congestion information, which could inform analysis of potential benefits and the scope of the appropriate incentive (if any).

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?

As noted above, AWEA supports a methodology based on shared savings of the benefits. It does not include a bright line metric, other than the benefits exceeding the costs. With *ex post* assessments, reductions in delivered energy costs will vary from forecasts and are subject to exogenous factors such as gas prices and demand growth, so clawing back incentives will reduce the regulatory certainty required for investment.

Q24: 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?

Yes. Incentives for accessing additional generation could be valuable for remotely constrained variable generation, when combined with broader transmission policy reforms. The declining cost of this generation and the ability to use complementary resources for both balancing and resilience provide significant benefits in cost and reliability that would otherwise be lost if they cannot interconnect to the grid. Scaling projects to meet current and *future* needs can, over longer time horizons, magnify the benefits by reducing the cost of future capacity expansions in existing rights of way. However, AWEA believes that this should be a central aim of transmission policy, and that incentives alone cannot support necessary transmission development aimed at additional generation absent reforms to planning and cost allocation.

Q25: 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?

The Commission could scale the incentive to match the expected level of benefit, adding additional compensation for projects satisfying more than one criterion.

3. 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?

Broadly speaking, policies should prioritize access to resources that enhance system optimization and provide access to lower cost remotely constrained resources.

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

Geographic areas denoted as renewable energy zones have been used to guide transmission planning decisions, such as in the Texas and California CREZ processes. These identified resource rich areas and identified transmission corridors with appropriate capacities told bring their energy to load centers. Some criteria for selecting renewable energy zones recommended by NREL are: resource quality; topography; compatible land use; developer interest; and the theoretical renewable energy resource potential (unconstrained by cost or land use issues) is the base layer for this process.[23] The Commission should consider adopting renewable energy zones as part of its overall transmission policy, including incentives.

Q28: Should the relevant geographic areas be defined on an ex ante basis and/or should the transmission developer have the burden of demonstrating that the relevant transmission project falls within a geographic region that has an acute need for transmission?

Geographic areas can be established *ex ante* by analyzing the generation profiles in a given area, as per NREL analysis of western wind and solar resources,[24] the quality and temporal

[23] Renewable Energy Zone Transmission Planning Process: A Guidebook for Practitioners Nathan Lee, Francisco Flores-Espino, and David Hurlbut | National Renewable Energy Laboratory, Golden, Colorado 2017

[24] *See* National Renewable Energy Laboratory, *Western Wind and Solar Integration Study*, https://www.nrel.gov/grid/wwsis.html.

availability of the resource for balancing and reliability, and improved regional power flows (as per MISO MVP projects).

4. 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 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 or one region. This non-monetary incentive 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.

5. Security/Resilience

Q34: Should transmission projects that enhance resilience be eligible for incentives based upon their reliability-enhancing attributes?

A modernized, integrated, and expanded transmission system is naturally a more flexible and resilient system; incentives specifically intended to accomplish greater resilience should be justified on a case-by-case basis.

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

The Commission can incentivize transmission that will provide 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 or one region. This non-monetary 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 traditional incentives or a proposed "shared savings" proposal.

6. 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.

Incentives to improve the use of existing transmission could be the most immediately impactful policy shift for the Commission to undertake through this proceeding. Congress provided specific statutory direction to the Commission to encourage better use of the existing system,[25] but this instruction has not been not been effectively implemented to date. In part, this may be because technologies capable of significantly improving the existing transmission system at relatively nominal cost (versus new lines) had not been fully demonstrated at the time the Commission issued its prior incentive orders and policy statement. Expected congestion cost

[25] 16 USC 824s(b)(3))

savings should be measured up front and shared between customers and the transmission owner using a "benefits" framework.

Dynamic Line Rating ("DLR") is a technology that is ripe for broader deployment. As the Department of Energy has indicated, "DLR technologies enable transmission owners to determine capacity and apply line ratings in real time. This enables system operators to take advantage of additional capacity when it is available."[26] DLR typically consists of a combination of hardware and software. While results can be variable depending upon specific transmission topology, the DOE report – based upon test deployments in Texas and New York - found that "Relative to static ratings, the DLR system released, on average, 30%-70% greater real-time capacity."[27] A more recent collaboration between DOE and PJM Interconnection found that the use of DLR on a single line would save customers more than $4 million per year in congestion costs.[28] However, this technology has not been broadly deployed, despite the potentially significant reliability and economic benefits. Other technologies identified in the NOI, including topology optimization,[29] energy storage, and power flow control, can further improve the utilization of existing transmission.

Another technology is the use of high-temperature conductors. High-temperature conductors can transfer twice the amount of power under the same conditions as conventional ACSR (Aluminum Conductor Steel Reinforced) type of conductors that are in use today.

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[26] Available at https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf.
[27] Available at https://www.smartgrid.gov/files/SGDP_Transmission_DLR_Topical_Report_04-25-14_FINAL.pdf at vi.
[28] Available at https://insidelines.pjm.com/pjm-finds-opportunities-in-new-dynamic-line-rating-technologies/.
[29] Available at https://www.brattle.com/news-and-knowledge/news/brattle-study-for-national-grid-shows-topology-optimization-can-help-relieve-major-transmission-constraints-in-great-britain.

AWEA supports the comments of the WATT Coalition regarding a potential framework for assessing benefits, identifying incentives, and deploying technology and operational measures to achieve this key statutory goal.

> *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?*

A technology-specific incentive might be useful to accelerate the adoption of such tools as flow controllers, high capacity conductors and automation, 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. For instance, dynamic line rating coupled with software improvements could support significant enhancements in the use of existing transmission assets. To the extent that the Commission believes that any particular technology or combination of technologies requires further record support before being eligible for an incentives, a technical conference or other mechanism may be appropriate to ensure that complete, up-to-date information is available to the Commission, and that useful technologies can be adopted as rapidly as possible.

> *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.

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?

Incentives have little value for regional planners and should more appropriately be focused on transmission sponsors or developers (to the extent they are used at all). The RTO/ISO is or should be required to manage a planning process that identifies and selects a wide variety of transmission system improvements.

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.

The Commission should include software upgrades, ramping enhancements and other innovative improvements among those measures eligible for incentives. Priority should be given to those investments which are breaking new ground.

7. 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?

As noted above, incentives may be appropriate for interregional lines in some circumstances; however, significant reforms to planning and cost allocation are needed before incentives could make a meaningful difference. Accordingly, the Commission should focus first on a suite of non-monetary incentives to motivate necessary investment in interregional projects. The specific types of non-monetary actions that serve as virtual incentives include:

a. Establish cost-allocation standards recognizing the full regional benefits of significant interregional 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; and

b. Establish performance-based metrics for new projects and allow new transmission technologies and non-transmission alternatives to compete to achieve such metrics at least cost, with transmission owner sharing a small portion of the cost savings from not making larger investment than necessary.

Q46: If the Commission were to grant incentives for interregional transmission projects, what incentive(s) would be appropriate?

The Commission should consider non-financial incentives. For example, the Commission could consider a planning preference, such as easier bar for the determination of need or the requirement that these lines be included in an enhanced interregional planning under a reformed Order 1000.

8. 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?

Monetary incentives will not help to address this much. Instead we recommend the nonmonetary measures we suggest regarding reform of Order 1000 planning and cost allocation, including integrated benefits assessments and meshing of reliability, economic, and public policy planning processes.

Q48: If so, what metrics could the Commission consider when evaluating whether a transmission project facilitates the interconnection of generation?

Incentives 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.

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 one 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.

9. 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 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 generally not attractive to independent developers because they increase project costs and affect project financing. 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.

C. Existing Incentives

1. RTO/ISO Participation

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

The Commission's encouragement of participation in independent system operators (ISOs) and regional transmission organizations (RTOs) has proven their benefits. AWEA's members are active participants in energy, ancillary services, and capacity markets, as well as the transmission planning processes which – thanks to ISO/RTO membership – encompass what were once multiple smaller balancing authority areas. Accordingly, AWEA requests that the Commission continue to incent current ISO/RTO members to remain in markets. As noted below, an enhanced incentive may be appropriate for the first several years of RTO membership, as a means of encouraging additional transmission owners to join. Additionally, some level of adder for membership in market elements without full RTO membership - such as the Energy Imbalance Markets offered by CAISO and proposed by SPP – would be consistent with Congressional direction in section 219.[30]

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

As noted above, AWEA believes the current RTO incentive has generally been effective, and that the benefits of organized markets support retaining it for current RTO members. However, the Commission should also consider an enhanced RTO adder for new transmission owners in ISOs/RTOs. Such an incentive might provide an enhanced adder for a limited period of time (for example, the first five years of membership), at which point it would revert to the standard adder.

2. **Advanced Technology**

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

As noted above, AWEA supports the implementation of incentives to improve the use of existing transmission facilities; most of the opportunities available to do so would use advanced

[30] *See* 16 USC 824s(c)(directing the Commission to provide for incentives to each utility that "joins a Transmission Organization). At 16 USC 796(29), "Transmission Organization" is defined to mean "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities."

technologies. Additionally, advanced technologies can be used for new, long-haul transmission lines. To the extent that advanced technologies are a "characteristic" of a transmission project, AWEA believes that focusing on the benefits of the advanced technology would be a more appropriate focus for the Commission. We believe that performance-based incentives compensated through shared savings provides a better option than focusing on the technology itself.

AWEA also believes the Commission should consider a proposal by the WATT Coalition that would provide for performance-based incentives designed along the lines of a program in operation in Australia. 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.[31] 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 existing transmission infrastructure, increase transfer capacity, alleviate congestion and enhance reliability.[32]

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

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

[31] For a recent analysis and proposal of how to integrate these resources, see: *A Proposal to Improve Grid Operations through Advanced Transmission Technology Deployment Incentives,* WATT Coalition Discussion Paper, Rob Gramlich, April 24, 2019.

[32] Id.

AWEA believes that the Commission should continue its non-ROE adder incentives, including regulatory asset treatment, construction work in progress (CWIP), abandoned plant recovery, and accelerated depreciation. The ability to establish a regulatory asset and lodge certain capital expenditures and incentives *before* a transmission project is operational is particularly valuable for non-incumbent transmission developers, who do not have an accepted rate on file. These incentives have been fairly successful and frequently used by transmission developers.

IV. CONCLUSION

WHEREFORE, AWEA respectfully submits its initial comments and requests that the Commission consider this input as it evaluates future refinements to its incentives policies, as well as broader improvements to its transmission policies.

Respectfully submitted,

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