BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL COMMENTS OF AMERICANS FOR A CLEAN ENERGY GRID

I. Introduction

Pursuant to the Notice of Inquiry issued in this docket on March 21, 2019,[1] by the Federal Energy Regulatory Commission ("Commission"), Americans for a Clean Energy Grid ("ACEG") is pleased to submit its initial comments. ACEG represents a diverse and informal coalition of stakeholders focused on the need to expand, integrate and modernize the high-voltage grid in the United States. In ACEG's view, enhancing the bulk power grid is a threshold precondition without which the achievement of numerous other vital national goals will not be possible. ACEG counts among its participating sponsors, partners, and supporters a full range of transmission stakeholders. The ACEG coalition includes multi-state utilities that develop, own, and operate transmission, trade groups that include transmission owners and transmission equipment manufacturers among their members, industrial consumers with clean-energy goals, renewable energy trade groups and advocates, advocacy groups for renewable energy, environmental advocacy organizations, and energy policy experts. ACEG seeks to educate the public, opinion leaders, and public officials to the needs and potential of the transmission grid and is pleased for that reason to have the opportunity to submit comments in this proceeding.

ACEG submits that the United States requires a highly reliable, resilient, interconnected, and affordable electric power system embodying transparent and competitive bulk power markets to optimize its economy for the benefit of all Americans. Simultaneously, it must allow a market-driven and policy-driven transition to a decarbonized electricity generation sector and therefore a clean energy economy to optimize the US environment and fulfill its responsibility to mitigate

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

global climate change. It must also accommodate an array of distributed resources, new customer options, and adapt complex system management tools based on torrents of real-time data. And it must do so even as our society and economy become ever more electrified in critical digital functions dependent on high power quality.

To meet these needs, the U.S. high-voltage power grid must be significantly improved in capacity, interconnection, reach, scope, technology, coordination, and protection from accidental and deliberate damage. New technologies can contribute cost-effectively to meeting these challenges but cannot substitute for the need to build or add transmission capacity where it is lacking. Although in rare instances the opportunity to eliminate connections to the grid might be a rational option for some small consumers, it is never likely to be feasible for consumers in densely populated areas, large consumers requiring high-voltage energy, or consumers without the technical and financial capability to maintain their own power supply and island themselves with adequate power quality. The backbone high-voltage transmission grid will therefore not only remain vital, but will require further expansion, integration, and modernization.

We applaud the Commission for launching this Inquiry into transmission incentives. It is an important step toward fulfilling the Commission's fundamental responsibility to create the policy and regulatory environment within which this future for the interstate high-voltage transmission grid can be realized. No other governmental authority at any level has greater authority, competence, or obligation to foster this future version of the electric transmission system in the United States. This Notice of Inquiry and any subsequent rulemakings or policy statements will go to the heart of that responsibility, identifying the incentives that should be adopted to induce such progress both by regulated entities and independent actors. ACEG is therefore very pleased that the Commission has signaled in this proceeding its own recognition that the transmission system in the United States requires improvement and seeks to identify policies that would provide the needed incentives to induce private actors to accomplish that improvement.

II. Summary

ACEG provides the following comments that roughly follow the outline of the Notice of Inquiry, addressing sequentially the proposed approach to incentive policy, the objectives that should be targeted by incentive policy, the efficacy of rate-of-return incentives applying to regulated transmission companies, and the process for implementing new incentives.

Fundamentally, to correct these failings, ACEG urges the Commission to open proceedings and act in the near term to:

- Expand the limited definition of benefits achieved by transmission investment for the grid and for electricity markets beyond economics and reliability to include resilience, ability to serve demand for sustainable energy, ability to meet public policy requirements, and other benefits detailed below;
- Address seams issues between and among transmission planning regions by requiring regional planners to adopt a simplified combined regulatory process as a "one-stop shop" for interregional or multi-regional transmission project proposals; and
- Adopt policies to encourage implementation of low-cost, high-benefit new transmission technologies on existing systems.

Over the longer term, as the Commission reviews and revises its various policies related to transmission, the Commission should:

- Broaden its vision and willingness to act to induce the needed improvements of the transmission grid under all its regulatory obligations and authority;
- Recognize that its historic approach to incentive policy omits the implicit incentives inherent in in transmission planning, cost allocation, and interconnection policies;
- Adjust its incentive policy to provide aid and assurances to state and local jurisdictions that object to transmission development that is perceived to provide little direct benefit, but significant costs or environmental, land use and aesthetic impacts; and
- Consider options to develop policies to overcome the dramatic differences in lead-time for the completion of new transmission lines and generator additions.

ACEG recommends first that the Commission's approach to incentive policy be consciously broadened to encompass the implicit incentives that are inherent in transmission planning, cost-allocation, and interconnection policies. While it is required under Section 219 of the Federal Power Act ("FPA"),[2] the Commission's transmission incentives policy also can be embodied in actions under FPA Sections 205 and 206 and other parts of the Commission's statutory authority. In the absence of planning and cost allocation reforms, incentives tied to ROE collected on operating transmission projects are necessary but not sufficient to induce the various stakeholders and sponsors to take the timely actions required now to add new long lead-time transmission capacity that will be available when needed, to integrate that capacity to allow bulk power markets to be fully transparent and efficient across the nation, and to modernize the transmission system with emerging technologies.

Existing incentives to transmission providers do not help at all in getting a new project accepted for planning, sited, permitted, or its costs allocated, because they do not motivate the decision-makers involved. Yet those are among the key hurdles to the expansion, modernization, and integration the grid requires. The promise of future ROE incentives when a project is complete and operating may increase a project sponsor's determination to achieve ultimate success, but does not make it more likely because it may not fully offset the barriers to multi-state and interregional projects posed by the multi-regional planning processes using differing standards, multi-jurisdictional siting and permitting processes, and determined local landowner opponents. The Commission should envision its entire structure of regulation as creating the proper balance of incentives and disincentives for regulated entities, market participants, and other authorities to take the actions required to further the public interest. A narrow review of specific financial rewards to developers of working transmission assets does not encompass the breadth of inducements to positive action on transmission that the Commission can and should create within its authority.

ACEG thus reviews the objectives that the Commission should design incentives to achieve. Without disagreeing with any of those the Notice of Inquiry ("NOI") posits, ACEG focuses in on those objectives that would have the greatest impact on improving the transmission system and achieving its full potential benefits. There are significant obstacles to the development of an

[2] 16 U.S.C. § 824s.

optimum interstate transmission grid that could be overcome if there were adequate incentives in Commission policies for key stakeholders, including but not limited to regulated transmission utilities.

A principal recommendation that ACEG makes in these comments is that the Commission broaden its limited definition of the benefits transmission systems achieve, because it is delivery of those benefits that warrants incentives. While economic efficiency and reliability are fundamental attributes any transmission investment should possess, there are a host of additional benefits to the public from the transmission system that are enjoyed by all electricity consumers in the region. All are served by energy priced in that broad regional and indeed interregional market, and benefit from the effects of lower cost energy brought to any portion of that market. All benefit if the new transmission offers cleaner air in the region and if it offers the potential for public policy objectives to be achieved. ACEG believes the Commission should identify all the benefits transmission brings, recognize the breadth of the beneficiaries, and allow that analysis to modify the cost-benefit ratio that is applied to judging transmission projects. Increasing the benefits relative to the costs in itself will encourage transmission investments.

A second major focus of ACEG in recognizing the need for incentives is the continuing problem of building interregional transmission up to and including stronger transmission links between the two major interconnections (and when possible, the Electric Reliability Council of Texas ("ERCOT")). This problem persists because the Commission's own regional market structure with Regional Transmission Operators and Independent System Operators in much of the country have focused exclusively on transmission planning within their regions and not on the broad opportunities for better energy system economics, reliability, and sustainability by building stronger connections between and among them. The answer is to adopt a simplified combined regulatory process for interregional or multi-regional transmission project proposals that would assure them no greater procedural hurdles than intraregional projects face.

Third, adjustments to the Commission's policies and practices can provide an incentive to address hostility to interstate transmission development where that hostility is most effective – in state and local regulatory jurisdictions. Especially in localities that perceive little or no direct benefit from a transmission project, but perceive significant environmental, land-use, and aesthetic penalties from the transmission line crossing overhead, Commission assurances about cost-allocation priorities and Commission support in spreading the costs of all studies and impacts regionally would be a significant incentive to achieve more timely and more positive regulatory action outside the Commission's own purview.

Incentives will not accomplish much if they do not address a fundamental quandary: new transmission projects take about five times as long to put into service as do the new generating assets that are in demand today. When it only requires two years to develop a solar, wind, or natural gas generating plant, but at least ten for the new transmission line that delivers their energy to the load hundreds of miles away, the transmission investments must go <u>first</u> and cannot be dependent on financial support from the future generators who do not need to begin work for another eight years. The Texas CREZ projects are the poster-case of how this can be done. But how to duplicate that success at the federal level is a different and difficult challenge.

Incentives can also help on existing systems that could gain significant capacity, efficiency and operational effectiveness through installation of new technologies, but do not get developed because the economics of new technology roll-out can conflict with the traditional return on rate-based assets business model. ACEG follows its coalition partner, Working with Advanced Transmission Technologies Coalition ("WATT"), in advocating a detailed fix.

To be clear, ACEG believes that certain "traditional" incentives, applied consistently and geared towards achieving the greatest level of net benefits to consumers, are a necessary component of a broader policy to incentivize needed transmission. These existing incentives include the RTO and Transco adders to return on equity, which can be fully justified through the prism of promoting needed behaviors and business models and achieving benefits for consumers. The RTO adder, for instance, supports the growth and stability of RTOs, which is a necessary precondition for regional planning and cost allocation. The Transco adder supports a transmission only business model in which capital is fully utilized to support transmission investment and ensures that there are voices within the industry fully committed to addressing challenges inherent to transmission development. These adders are vital to future investment and should be maintained. In general, ACEG believes the Commission should value stability for existing incentives that have provided the backbone conditions for transmission development in the past.

In short, ACEG does not dispute that the Commission's ROE incentive policies have been warranted and remain beneficial. However, given the urgent need for proactive grid investment, these existing incentives may prove inadequate to achieve the broader objectives the Commission itself identifies. This is because ROE incentives simply do not apply to many of the stakeholders whose decisions shape and define the grid and its benefits to consumers but who are potentially influenced by Commission Policies. Therefore, it is time for the Commission to adopt a broader policy focused on promoting proactive and holistic grid planning and cost allocation rules that will provide the greatest level of benefits to consumers and support our nation's policy goals.

III. The Commission's Approach to Incentive Policy Should be Broad Based.

Webster's New Collegiate Dictionary defines "incentive" as "something that incites or has a tendency to incite to determination or action." The Commission should use the inquiry opened in this proceeding to examine the full range of its authority for steps that could "incite determinations or actions" by transmission owners and **all** others that would lead to the enhancement of the transmission grid.

Transmission incentive policy is only one regulatory tool for driving needed grid development; other regulatory reforms should be made in parallel. In the face of the multi-faceted challenges confronting the transmission grid, ACEG submits that the response sought by the Commission by embedding incentives into its policies should be broadly conceived and implemented. This should include maintaining incentives that have proven to support beneficial investment, like the RTO and Transco adders, while also addressing the range of issues that continue to present roadblocks and could be ameliorated by modifications of other Commission policies. The Commission bears lead responsibility for the bulk power system's planning, economics, operational practices, and relationship to the retail distribution systems that deliver most of the power to ultimate consumers. Incentives and disincentives are embedded and implicit in all of the Commission's rules and practices.

The Commission should therefore examine its opportunities to advance the healthy growth and modernization of the grid from a broad perspective, recognizing that the regulations the Commission adopts can drive needed actions by any or all stakeholders in the future of our electric delivery system, including actions by customers, state authorities, distribution utilities, equipment manufacturers, generators, and also the Commission's regulated regional transmission organizations and independent system operators. While this inquiry arises from the Commission's concern about the effectiveness of its actions under its authority in Section 219 of the FPA, the Commission is clearly able to consider modifications of its policies under other sections of the FPA that could have the effect of driving transmission grid enhancements.

The rates set by the Commission for transmission, and the Commission's practices in allocating the costs that those rates recover, can have the effect of creating monetary incentives or disincentives for customers to seek "non-transmission alternatives." Owners and operators of transmission should not be put into conflict between what is best for the public interest and what best serves their investors. Rate policies should clearly be structured so that transmission owning or operating companies charging Commission-approved rates are not only made whole but are incented to optimize their systems and services.

Non-monetary incentives and disincentives are also implicitly present in the Commission's policies for planning transmission additions and for managing interconnection of new resources. Where there is a multi-year queue of generators awaiting transmission services there is an effective disincentive for development of what may be the highly cost-effective generation. Where a highly cost-effective transmission project cannot obtain siting approval from state and local authorities, Commission policies can potentially provide incentive by ensuring that the benefits in those states and localities are demonstrated to exceed the allocated costs. All stakeholders in the transmission of electricity should be induced by Commission policy to take the actions that support the optimum development and use of the grid, including entities the Commission does not directly regulate.

The Commission's authority to require planning and allocate costs of transmission investments should reflect the full range of identifiable benefits that flow from those investments. It should include the Commission's authority to review and adopt standards set by the North American Electric Reliability Corporation. The Commission should examine **each** of its actions and decisions with regard to its electricity jurisdiction from the perspective of whether that action or decision incites movement toward or away from a more integrated, extended, secure, sustainable, and modernized power grid as a key element of affordable, reliable and resilient electricity service. Finally, the Commission should recognize that removing a disincentive to engage in a positive action is a powerful means of providing an incentive to do so.

The Commission should not see its statutory authorities under the FPA or other acts as somehow being "siloed" in ways that require separate and independent proceedings and regulations, such that any policy explicitly aimed at providing incentives for needed interstate transmission improvements can only be justified if it is somehow specifically authorized by the provisions of Section 219 of the FPA. This broad view is clearly supported by the intent of Congress in enacting Section 219 of the FPA in 2005. Congress called for the establishment of rules promoting "reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of such facilities."[3] Congress further required that FERC "encourage the deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities."[4] The adopted rule was mandated to provide incentives for electric utilities to join a Transmission Organization[5] (defined in the statute to include both Regional Transmission Organizations and Independent System Operators[6]). Congress thus anticipated benefits to the public from regional transmission organizations that warranted incentives to participating utilities. Congress explicitly authorized performance-based rate treatments,[7] but did not specify what elements of system performance would warrant such incentives. ACEG submits that the Commission should take a broad view of the characteristics of performance that

[3] 16 U.S.C. § 824s(b)(1).
[4] 16 U.S.C. § 824s(b)(3).
[5] 16 U.S.C. § 824s(c).
[6] 16 U.S.C. § 824o(a)(6).
[7] 16 U.S.C. § 824s(a).

transmission systems might ideally exhibit and should define the metrics and provide incentives for such performance.

In the comments that follow, ACEG submits that the Commission should adopt policies that would lead to:

- Consideration of the many benefits of transmission, several of which are not currently recognized in the planning or cost allocation processes, to allow the reallocation of costs to beneficiaries that not currently paying for real benefits they receive at the expense of other customers;
- Significant new interregional transmission capacity for purposes of improved reliability and resilience and achieving the deliverability of non-dispatchable but least-cost resources, especially those currently remote from transmission capacity;
- Significant interconnections between the Eastern and Western interconnects, and potentially also between them and ERCOT if jurisdictional issues are clarified satisfactorily;
- Mitigating the burdens and natural reluctance on the part of states, communities, and landowners to accepting new transmission rights of way;
- Fostering anticipatory transmission projects to regions with proven low-cost energy-generating resources that cannot reasonably be expected to be developed until transmission capacity is committed, financed, and under construction; and
- Upgrading existing transmission capacity or performance with new technologies.

The transmission system in the United States currently suffers from a number of constraints that block progress toward the expanded, integrated, and modernized grid of a more sustainable future. The Commission should adopt transmission policies not only to achieve a better outcome for customers, but also to correct currently unjust, unreasonable and unduly discriminatory results in the electricity markets the Commission regulates as a function of its failure to require or induce transmission providers to improve their capacity and services. ACEG submits that the current transmission situation effectively presents unjust, unreasonable, and unduly discriminatory terms and conditions for access to transmission services that could be corrected if the Commission were to adopt policies that include implicit incentives for better performance by various concerned interests. Specifically:

- The Commission can move expeditiously to correct substantial disparities among regions and balancing areas in transmission planning standards and practices;
- The Commission could swiftly identify and recognize for planning and cost allocation all regional and interregional benefits of transmission projects to which at least some costs of transmission should be attributed, avoiding a situation where some beneficiaries escape any responsibility for the costs of a project creating benefits they enjoy;
- The Commission has recognized that transmission incentives are appropriate for projects that achieve lower delivered costs by reducing congestion, but could also formally recognize in this proceeding that a total lack of transmission capacity from regions with abundant low-cost generating resources is the ultimate form of transmission congestion;
- The Commission could create specific incentives for transmission capacity to be planned and built in anticipation of generation that requires a much shorter lead-time to be on line;
- The Commission could require meaningful interregional (and indeed national) transmission planning in light of analyses demonstrating high potential benefits for consumers; and
- The Commission could create a business environment where transmission owners and operators consistently opt for technologies with the greatest net benefit to consumers, rewarding their better performance and not merely their investment.

This inquiry offers an excellent opportunity to begin addressing these issues and should be viewed as launching an effort that may broaden into additional proceedings. ACEG recognizes that addressing these issues may take the Commission into issues that were addressed initially in its Order No.1000,[8] and understands that there has been reluctance to reopen some of those issues. At this point, however, ACEG urges the Commission to examine these issues and opportunities to address them from the perspective of incentives policy, and to make changes in the regulations adopted in Order No. 1000 as may be necessary to ensure that the transmission development goals of Section 219 of the FPA and Order No. 1000 are both met.

---

[8] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶61,051 (2011); *order on reh'g,* Order No. 1000-A, 139 FERC ¶61,132; *order on reh'g and clarification,* Order No. 1000-B, 141 FERC ¶61,044 (2012); *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d 41 (D.C. Cir. 2014).

ACEG also appreciates the Commission's inquiry[9] as to whether the "project risks and challenges" framework adopted in Order No. 679[10] should be retained, and respectfully submits that such a framing is now clearly too narrow, because it focuses exclusively on given proposed projects, when the true "risks and challenges" the grid faces and the consuming public experiences with regard to transmission are societal and multi-regional if not national. The Commission should focus on enhancing the capacity and function of the entire electric grid, not piecemeal project segments. It should recognize that the benefits provided by the grid as a whole are far more than the sum of the benefits linked to the individual transmission lines. The individual parts of the grid, when operated together in an integrated system, provide broad economic, affordability, resilience, and environmental benefits that cannot be readily quantified and assigned at an individual project level. Therefore, the Commission should adopt as a result of this proceeding a new holistic approach to assessing the benefits the grid offers to all consumers, recognizing that individual segments contribute to those benefits beyond their specific linear paths, and beyond the service areas of individual utilities, and adopt policies that support those systemic benefits.

If the Commission determines to maintain a risks and challenges approach to awarding incentives, it should identify risks and challenges on a regional basis, and to reward transmission projects that contribute to meeting these challenges at the least cost. The failure to develop an improved high-voltage transmission system creates risks that consumers throughout and beyond that region will pay unreasonably high prices for energy, that the assurance of reliability will be degraded, that the restoration from an outage will be less effective, that public policy goals for controlling pollution will not be met. Avoiding these risks presents challenges not merely to a given project proponent, but to the consuming public and indeed the national interest.

IV. The Commission Should Identify and Quantify All Transmission Benefits for Cost-Allocation Purposes

In requiring for planning and cost allocation purposes the recognition of only two benefits – delivered energy costs and reliability – the Commission fails to recognize other benefits that

[9] Notice of Inquiry at P 15.
[10] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, 116 FERC ¶61,057 (2006); *order on reh'g,* Order No. 679-A, 117 FERC ¶61,345 (2006); *order on reh'g,* 119 FERC ¶61,062 (2007).

consumers and residents of the market region unquestionably receive. Recognizing those benefits would make it easier for a project sponsor to make a compelling cost-benefit case, and thus serves as an implicit incentive for project sponsors to proceed with confidence. ACEG urges the Commission to remove the artificial limits to the benefits of transmission that are recognized in project approvals and cost allocation. The Commission should require all regions to recognize **all** the identifiable benefits of transmission projects for purposes of planning, and to do so in a consistent and holistic manner.

The NOI explicitly suggests that a new incentives policy might be based on "expected project benefits."[11] It then poses a series of questions (Q4 through Q7) that ACEG answers below. But the NOI's preface to this subsection suggests that such benefits would be limited to "benefits related to reliability and reductions in the cost of delivered power by reducing transmission congestion."[12] This represents an unreasonably confined view of the benefits that transmission confers on consumers and that should thus be considered in building transmission for them and allocating transmission costs to them. For example, Order No. 1000 expanded the examination of transmission benefits to include the value of meeting public policy objectives.[13]

In fact, there are numerous demonstrable benefits of transmission that should not be ignored in evaluating transmission projects for inclusion in regional plans and cost allocation. <u>Requiring planning regions to regularly identify and quantify these benefits, even if some can only be roughly estimated, would constitute a significant incentive to transmission project sponsors because it would increase the benefits of the critical cost-benefit ratio without any increase to the costs</u>. These benefits represent real values to the grid, to consumers, and to the broader society and economy the grid serves, and they are enjoyed in many cases throughout the broader interconnection, market region or interconnection within which the specific project is built. In the same way that regional transmission planners should give due consideration to the potential for demand-side measures and non-transmission alternatives because of the benefits they may offer, they must not ignore any of the benefits a transmission project can offer.

[11] Notice of Inquiry at P 16.
[12] *Id.*
[13] Order No. 1000 at P 203.

Perhaps the most definitive and comprehensive analysis of transmission benefits was that prepared for WIRES in 2013 by the Brattle Group.[14] ACEG urges the Commission to consider this report and to expand the recognized benefits of transmission to be included in any cost-benefit evaluation accordingly. On the following page, ACEG reproduces the table of transmission benefits Brattle listed, including the many categories of benefits identified in the report, analyzed for their estimated monetary value to the extent possible, judged for their overall benefit, and discussed as to how they might be reflected in cost allocation.

Such benefits should be considered both in the process of planning transmission and in the process of allocating its costs to rates. And when they are considered and incorporated in decision-making by regional planners and federal regulators, ACEG submits that State and local authorities too will be unable to avoid at least addressing them and likely unable to deny them, even if they elect to continue ignoring them in many cases. Merely getting such real benefits into the decision-making discussion would be a step forward. In addition, acknowledging additional benefits in project benefit /cost analyses would allow transmission developers more leeway to cover the costs of mitigating landowner impacts and community concerns within a still positive cost/benefit calculation.

---

[14] Judy W. Chang, Johannes P. Pfeifenberger, J. Michael Hagerty, "*The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments,*" prepared for the WIRES Group by The Brattle Group, July 2013, available at: https://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

POTENTIAL BENEFITS OF TRANSMISSION INVESTMENTS[15]

1) **Traditional Production Cost Savings** –
   Production cost savings as traditionally estimated
   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

2) **Reliability and Resource Adequacy Benefits**
   a) Avoided/deferred reliability projects
   b) Reduced loss of load probability <u>or</u>
   c) Reduced planning reserve margin

3) **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

4) **Market Benefits**
   a) Increased competition
   b) Increased market liquidity

5) **Environmental Benefits**
   a) Reduced emissions of air pollutants
   b) Improved utilization of transmission corridors

6) **Public Policy Benefits**
   a) Reduced cost of meeting public policy goals

7) **Employment and Economic Development Benefits**
   a) Increased employment and economic activity;
   b) Increased tax revenues

8) **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 and customer congestion- hedging value, and HVDC operational benefits

---

[15] *Id.*, at p. ***v***, excerpted with permission of WIRES.

In answer to question Q4, ACEG submits that examining the prospective benefits of a project in considering the project within a regional or interregional transmission expansion plan constitutes an obvious element of the review, and that examination should attempt to perceive those benefits throughout all the portions of the relevant interconnection in which the project would operate. ACEG acknowledges that the drawback to this approach is the difficulty of achieving hard quantifications of those benefits. Some are inherently hard to quantify, such as the benefit of improved resilience to unexpected outages. And quantification of benefits is also made difficult when the benefit is spread throughout one or more large regions. The benefit of increasingly competitive delivered power rates in a market can be calculated if the market is distinct, but the transmission itself will have the effect of erasing market differentials. On a multi-regional basis, ACEG's own studies in MISO and PJM have indicated that the cost of the transmission expansion required to deliver low-cost renewable energy is typically more than offset by the net savings in delivered power prices in the market region.[16]

ACEG submits in answer to Q5 that the Brattle Report provides an excellent set of general principles for allocating costs in line with benefits. The key attribute to keep in mind about the many benefits the Brattle report identifies and analyzes is that they are regional, accruing to the consumers and the economy within the region in which the transmission investment is made. Indeed, some of the benefits, such as environmental and economic benefits, are effective inter-regionally, nationally and even globally. In accordance with the classic regulatory principle, the costs of a project should be allocated to the beneficiaries of that project.[17] Just because the beneficiaries are a broad range of direct and indirect energy market participants doesn't mean that they should not be assigned to bear a share of the costs. Of course, it would not be possible to achieve global cost allocation even as the entire world might benefit, for example, from the greater ability to substitute clean energy for energy producing carbon emissions. But the Commission

[16] *See* The Net Benefits of Increased Wind Power in PJM , Final Report, May 9, 2013 (https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-05.EFC_.Increased-Wind-Power-in-PJM.12-062.pdf); The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region, Revised Report, August 31, 2012 (https://www.synapse-energy.com/sites/default/files/SynapseReport.2012-08.EFC_.MISO-T-and-Wind.11-086.pdf); and Midwest Wind and Transmission: Rate Impacts Analysis, Prepared for Americans for a Clean Energy Grid, May 22, 2012 (https://www.synapse-energy.com/sites/default/files/SynapsePresentation.2012-05.EFC_.MISO-T-and-Wind-Presentation.11-086.pdf).

[17] This, in fact, is one of the Regional Cost Allocation principles in Order No. 1000. Order No. 1000 at P 622.

should find that some allocation of costs on a broad regional or interregional basis from a given project with demonstrable regional or interregional benefits is "roughly commensurate" with those benefits.[18]

In answer to Q6, proponents will be heartened by the formal recognition of the savings their projects will generate and strengthened in their arguments for permits and cost recovery. They will have more confidence they can proceed, and thus certainty. Additional incentive, such as an adder to the rate of return for a highly-beneficial project, may be less necessary if the listing and monetization of all its benefits allows it to move forward rapidly. In answer to Q7, all transmission projects would be likely to benefit from greater regulatory recognition of the regional and market benefits they create. Specific financial benefits might be particularly provided to those incentive applicants that fully demonstrate and quantify the benefits they claim to offer. Financial incentives might also be especially appropriate for projects that offer benefits that are truly unique to that project and not broadly enjoyed, such as the category listed on the Brattle table as "Other Project-Specific Benefits."

ACEG therefore recommends that the Commission propose and adopt rules identifying the manifold benefits of transmission to be considered by planners and cost-allocators in the regions, and articulating the means of quantifying those benefits to be compared with project costs for purposes of allocating those costs to consumers in rates. ACEG further recommends that the Commission recognize that because the benefits are enjoyed well regionally and inter-regionally in many cases, it must adopt a mechanism that ensures that the costs are allocated regionally and inter-regionally where appropriate. ACEG believes that the affirmation of Order No. 1000's regionalization of costs of approved projects within that region would equally apply to allocating costs to more than one region when the investment involved was made in more than one region and should apply to all benefits discerned and estimated.

[18] *See* Order No. 1000 at PP 622-623; *Ill. Commerce Comm'n v. Fed. Energy Regulatory Comm'n*, 576 F.3d 470, 477 (7th Cir. 2009).

V. The Commission Should Adopt Policies That Provide Incentives to Develop Interregional and Interconnection-linking Transmission Projects.

The high-voltage transmission grid in the United States has evolved into three functionally synchronous interconnections in the East, the West, and ERCOT Texas. This is the current phase of the continual historic enlargement of electricity networks that started with the neighborhood service pioneered on Manhattan Island by Thomas Edison, leading to municipal utilities, then to regulated private utilities serving full metropolitan regions, expanding or amalgamating into larger entities overlapping state boundaries and leading to federal regulation as interstate commerce, and then interconnecting regionally for reliability and power quality purposes. But those interconnections are subdivided into smaller regions for retail utility regulation, and separate utility service areas or balancing areas have further limited electricity transmission transfer capacity well below optimum not only among but within those three interconnections.

The Commission's leadership in developing regional transmission organizations and independent system operators has positively addressed the internal integration of transmission operations within those defined regions. Ironically, this progress has actually had the effect of deterring *inter*regional transmission connections and projects, because it focused the attention on opportunities for *intra*regional gains and has led to the development of separate and contrasting planning and operational parameters in different regions.

The benefits of interregional transmission that clearly come from linking balancing areas or regional transmission organizations also extend to the long-envisioned ultimate configuration of the U.S. high-voltage system, a truly national power grid. The National Renewable Energy Laboratory completed a comprehensive modeling study in July 2018, called the *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, compared to today's scattered, short, and weak links between the interconnections.[19] Extensive participation and input from grid operators and electric utilities helped ensure that the results were realistic and achievable.

[19] The study is still pending release at the U.S. Department of Energy, but was presented in detail at Iowa State University at the Trans-Grid X Symposium by NREL's Aaron Bloom using the presentation available at https://cleanenergygrid.org/wp-content/uploads/2018/08/NREL-seams-transgridx-2018.pdf.

The Midcontinent Independent System Operator, Southwest Power Pool, and Western Area Power Administration were partners on the research team, and more than 20 utilities and grid operators participated on the study's technical review committee. Released at the TransGrid-X 2030 Symposium at Iowa State University in July 2018, the study determined that all three of the scenarios would make the grid more national and flexible in nature, with positive reliability and economic benefits as well as the ability to tap as yet non-producing resources of renewable energy. Under all three scenarios, the benefit-to-cost ratio was positive, reaching 3.3 to 1 in the case of a large capacity high-voltage DC overlay that integrated the East and West interconnections.[20] ACEG submits that, in light of such analysis, it is incumbent on the Commission to examine policies, including incentives policies, that would be helpful in instigating not merely interregional transmission projects of clear benefit, but also such national interconnection-linking projects such as the study hypothesized.

Order No. 1000 required regions to *engage* in planning internal capacity but required only undefined *coordination* among regions regarding projects that proposed to cross regional seams.[21] As a result, the RTOs and ISOs developed unique planning parameters and preferences for internal purposes but failed to align with those of neighboring regions. Little actual coordination has occurred. Any project sponsor proposing an interregional transmission investment has been required to pursue the project separately in each of the regions where it would be built. Thus proponents of interregional projects faced conflicting demands, multiple redundant processes, and separate decisions that, if any were negative or imposed conflicting conditions, frustrated the project sponsor's ability to proceed. Without coordinated and unified transmission planning and cost allocation when a project proposes to cross regional seams, there have been and are likely to be almost no significant interregional transmission projects developed and included in Order No. 1000 plans. Therefore, interregional transmission projects that could uniquely benefit consumers by creating market access for highly economic sources of low-cost energy, clearing bulk-power

[20] Although the Texas interconnection, ERCOT, was left out of the NREL analysis, there are already modest interties between ERCOT and the Eastern and Western interconnections. Subject to adequate guarantees of ERCOT's jurisdictional autonomy, which might require Congressional action, there are no technical or market reasons why more significant interconnections could not provide interregional benefits involving Texas production and consumption of power. ACEG does not suggest, however, that Commission incentives could overcome the current jurisdictional barriers.

[21] *See* Order No. 1000 at P 368-369.

markets over wider areas, and providing enhanced reliability and resilience have not been developed.

The NOI directly acknowledges this problem.[22] In response to Q44, the Commission should use incentives to encourage interregional transmission projects. Clearly, incentives provided directly to project sponsors do not overcome seams issues, intraregional myopia, or conflicting state priorities. But changes in other FERC policies adopted pursuant to authorities in Sections 205 and 206 of the FPA can have the effect of incentivizing a more rational recognition of the benefits of interregional transmission opportunities and their incorporation in to the grid.

Since removal of a disincentive can have the same ability to induce positive behavior as the addition of an incentive, ACEG recommends that the Commission first act to remove the disincentive to interregional projects that arises from the current practice that such a project must be separately approved for planning in each of the regions in which it is located before it can be fully accepted. The burden should be placed on the Order No. 1000 regions involved, **not** on the project sponsor, to collaborate with each other to offer a single and timely unified process for considering the project and its potential benefits and costs in all the regions it would propose to link. To the extent this forces adjacent regions to align their processes, agree on common standards, and reflect all benefits in all areas served in a common allocation of project costs to all areas benefitted, this will be beneficial to the grid as a whole, moving toward regulatory consistency and a broader view of the public interest.

The NOI asks at Q45 whether all interregional projects should be entitled to use such an incentive. Certainly all interregional project proposals should be entitled to a unified single planning process as proposed above. However, ACEG does not advocate that interregional projects be selected for regional plans unless they demonstrate positive benefits or at least no negative effect on the **grid** in the regions they propose to cross or serve. Competition with intraregional projects claiming the same or greater benefits and from proponents of non-transmission alternatives would be considered as well. Environmental impact cannot be avoided most instances, so such impacts

[22] Notice of Inquiry at P 30, Questions 44 – 46.

cannot be a disqualification, but instead a basis for evaluation, mitigation and minimization in the planning process.

ACEG answers Q46 by proposing that the Commission upgrade the mandate in Order No. 1000 from a requirement that RTO/ISO and other balancing regions cooperate with each other on proposed interregional projects to a requirement that they establish a **combined one-stop project review process** for reviewing interregional project proposals proposed to be included in the relevant regional plans. The combined review would function with designated personnel from each of the involved regions and would conduct a thorough examination of all costs and benefits the project sponsor presented, weighing each region's particular exposure to both. The review panel would reach a preliminary decision on project acceptability for planning that would then be reviewed by the regional entities, which could file exceptions. Having a single process to review interregional projects for inclusion in regional plans would remove a significant disincentive to potential sponsors to propose them, as it significantly reduces the cost of proceeding in separate sequential regional processes and lessens the risk of rejection on the basis of a single region's self-interested veto.

The regional portion of each interregional project that was approved would be included in each region's Order No. 1000 plan. While each such project should benefit from a single unified multi-regional review, the burden should then be on the project sponsor to demonstrate in that review that the project brings significant benefits to each of the regions that it serves or crosses, and at a minimum has no negative effect on the transmission of power within any region while benefitting the other regions.

Such an interregional or multi-regional evaluation of a project proposal would of course require objective analysis to confirm its benefits and expected costs, and such analysis should also be conducted in a unified manner for all regions involved. Regionally separate environmental and impact analyses are unlikely to be able to support an interregionally combined planning process effectively. Assistance from the Commission staff to identify potential resources in the Department of Energy or its national laboratories could be helpful in addition to support and guidance that might come from the Commission's own environmental experts. Making the Commission's expert environmental analysis resources available for evaluation of such projects, especially to those regions or jurisdictions resenting the costs of even evaluating a project from which they perceived little or no internal benefit, could reduce barriers.

The Commission approaches the issues involved in interregional transmission development more obliquely in its questions related to "Economic Efficiency Benefits"[23] and "Persistent Geographic Needs."[24] While interregional transmission incentives are not directly raised with regard to economic efficiency, there is no doubt that one principal driver for proposals of interregional transmission projects is the potential economic efficiency that could be gained from connecting the generation market more to load over long distances for potential energy cost savings as well as for improved access to increasingly low-cost and valuable renewable generation. ACEG answers Q22 and Q24 affirmatively: the Commission should focus its ability to create incentives on projects that can transmit additional generation that lowers total consumer costs for delivered energy. In particular, the Commission can help accomplish the objectives of accessing our lavish potential for increasingly valuable and decreasingly costly wind and solar energy in its often remote locations where there is little if any local electricity load.

ACEG answers Q23 and Q25 by suggesting that the Commission focus its justification for incentives less on production cost, and more on delivered energy costs and desire for certain types of energy generation in downstream markets, after considering incremental transmission costs. Any "bright line" should go beyond support for projects that promise significant delivered energy savings, to assist with incentives those projects that help meet state or local policy objectives or energy source preferences of consumers (such as corporations with established clean-energy goals).

"Persistent geographic needs" could serve as shorthand for another principal driver for interregional generation: the fact that so much of the nation's best potential resources of renewable energy are effectively remote from **any** transmission capacity, which, as noted earlier, is the ultimate form of congestion. ACEG submits that the Commission should definitely take into account in designing incentive policy (and transmission planning policy) the geography of the grid

[23] Notice of Inquiry at P 24, Questions 22-25.
[24] Notice of Inquiry at P 25, Question 26-28.

and those areas where economic efficiency potential is clear and reliable transmission from as well as to stakeholders is lacking.

In answer to Q26, the Commission could rely on detailed federal assessments of wind and solar energy potential by the National Renewable Energy Laboratory among others, in addition to noting existing queues of prospective generators, to understand the promise of specific geographical regions from which projects are proposed to originate, calibrating its incentives accordingly. Energy consuming regions where there are unfulfilled public or private goals for clean-energy consumption could be similarly favored by incentives for projects that will help meet those targets. With regard to Q27 and Q28, the Commission could establish policies identifying in advance major areas currently underserved with capacity that would warrant incentives, but also should be open to project sponsors' showings that their projects offer cost-effective ways of integrating isolated or underserved regions into the national grid.

VI. Commission Policy Changes Could Provide Incentive to Overcome the Major Obstacles to Transmission Development Arising Outside Commission Jurisdiction

In ACEG's view, core obstacles to both interstate and interregional transmission projects are the rights-of-way, licenses, and permits needed from multiple state and local jurisdictions, each of which has significant authority to reject or condition the project unacceptably, or in some cases lack the authority to approve a project that does not directly and significantly serve the consumers in that state.[25]

Congress' attempt in the 2005 Energy Policy Act[26] to create an effective Federal back-stop siting authority that would overcome state regulatory obstacles has not been effective. Parts of FERC's implementing regulations which construed the statutory authority to allow FERC action where a state siting authority had affirmatively denied state permits were invalidated by the 4th Circuit Court of Appeals.[27] Moreover, the authority is available to FERC only for projects within

[25] For example, Clean Line Energy cancelled a $2.5 billion high-voltage direct current transmission project designed to move wind power to eastern load centers after the Arkansas PSC found that the project was not eligible to receive a certificate of public convenience and necessity under state law. The Sunzia project has been delayed due to a denial by the New Mexico Public Regulation Commission on right of way issues.
[26] 16 U.S.C. § 824p, as added Pub. L. 109-58, title XII, § 1221 August 8, 2005, 119 Stat. 946.
[27] *Piedmont Environmental Council v. FERC*, 558 F. 3d 304 (4th Cir. 2009).

DOE-designated National Interest Electric Transmission Corridors. However, DOE's initial attempt to designate such corridors was invalidated on judicial review by the 9th Circuit Court of Appeals,[28] and DOE has not subsequently designated any corridors. A legislative proposal to strengthen the Federal back-stop siting authority was deemed too controversial even to be considered in bipartisan energy legislation that was reported the Senate Energy and Natural Resources Committee.[29]

ACEG submits that while direct Commission action to solve this jurisdictional divide may not be feasible, the Commission could and should use this proceeding to increase its awareness of how changes in its own planning, cost-allocation, and ratemaking policies might increase the positive impacts of interstate electric transmission projects and diminish their perceived negative impacts in jurisdictions the project touches, providing indirect incentives to achieve better state and local support for projects that serve the broader regional and national public interest the Commission perceives.

Clearly, a jurisdiction where a project proposes to interconnect with new power generation – which will bring significant jobs, economic development, and tax revenues – should have strong incentives to favor the transmission links to downstream markets without which those benefits are not possible. Similarly, jurisdictions where a major new outside source of power to meet local load requirements and required for economic, public policy, resilience, or reliability reasons should have significant incentive to permit an interstate transmission line to deliver that power. Even in those jurisdictions, however, local communities and land-owners bearing the direct impacts of the project can be expected to offer opposition, and potentially to prevail. In "pass-through" states that are neither exporting nor importing the energy transmitted, it is currently hard to expect siting and permitting approval, especially if there are system costs allocated to utilities within that state. Because the economic benefits of reducing congestion and facilitating more transparent and responsive bulk power markets extend to the entire region or even interconnection, state or local

[28] *California Wilderness Coalition v. DOE*, 631 F.3d 1072 (9th Cir. 2011).
[29] In 2015, Senator Martin Heinrich introduced a bill to amend the FPA section 216 to improve the siting of interstate electric transmission facilities, and for other purposes, in the Committee on Energy and Natural Resources. A bill to amend the Federal Power Act to improve the siting of interstate electric transmission facilities and for other purposes, S. 1017, 114th Cong. (2015). However, despite bi-partisan support, this bill did not make it out of committee.

decision-makers may believe that their own share of the benefits does not come up to their allocated share of the project costs. Environmental benefits are similarly broad while environmental impacts are linear and significant, often tilting state and local authorities into project opposition.

The question then is what incentives could be embedded in Commission policies, or what disincentives might be removed from them, that would induce state and local authorities to look more positively on proposed interstate and interregional transmission projects. The NOI approaches this question most closely in Subsection 12, Transmission Projects in Non-RTO/ISO Regions, with Q56[30] asking what incentives might encourage development of transmission in non-RTO/ISO regions, but incentives even within RTO/ISO regions may be helpful to overcome opposition to siting and permitting new transmission facilities. The NOI also raises the issues of "unlocking locationally constrained resources."[31] The constraints in question may well be the result of negative state and local decisions on transmission projects that would have unlocked those resources.

The underlying question is what type and form of incentives adopted by the Commission could motivate other jurisdictions to be more friendly to new interstate transmission projects in exercising their own authority to evaluate, site, and permit such projects. ACEG submits that the Commission should evaluate the reasons for which state and local authorities typically reject projects, then consider whether there are Commission rules or policies that make those rejections more likely, and finally evaluate whether acceptable changes to those rules or policies could make them less likely.

This is without prejudice to ACEG's earlier assertion that many benefits of transmission are broadly enjoyed in whole regions and interconnections, but the allocation of costs to passive recipients of such diffuse benefits would likely be modest. To the extent the benefit for air quality or decarbonization of a given project were a clear value sought by some downstream customers but not by others upstream along the proposed right-of-way, the project costs attributed to that benefit of the delivered power could similarly be pro-rated as a function of the respective public policy mandates in the respective jurisdictions, diminishing a disincentive for the upstream jurisdiction to

[30] Notice of Inquiry at P 35.
[31] Notice of Inquiry at P 31.

favor the project. But it is unduly discriminatory, in ACEG's view, to assign **all** costs of a project to the load serving entities in the jurisdiction that imposes the public policy requirements if there are economic, reliability, and other benefits that accrue more broadly, as there would undoubtedly be in a multi-jurisdictional region.

As another example, the Commission has the authority to determine that rates are just and reasonable even if they include costs beyond the actual documented costs of the physical equipment, labor, and right-of-way required by an interstate transmission project.[32] If FERC were to reinforce its policy of permitting transmission project developers to include in their project costs expenses that were incurred to mitigate the concerns of a local community inclined to oppose the construction of a nearby transmission line, a less contentious project approval could save more than their cost. This might include such expenses as providing a new railroad track overpass, upgrading a school or community center, or repaving some of the community's streets. The ability to make such social investments could help build the case for state and local acceptance of a project, and could allow that transmission line to be completed more quickly and perhaps at lower overall cost than if the costs for delay and opposition (and potentially abandonment) were experienced by the project sponsor and passed through eventually to customers. The project sponsor would have to demonstrate that the cumulative costs of such efforts to build support for the project did not totally offset its economic efficiency and other benefits, making it an unreasonably costly venture.

Individual land-owners too can be vigorous and effective opponents of a transmission project, vociferously influencing state regulators and local authorities to believe that the lost viewscape values exceed any gain to their state or locality. Landowners whose kitchen-window view is forever altered by a set of transmission towers on neighboring land should not be assumed to be entitled to no compensation, as their environment and the value of their property may have

---

[32] Utilities may recover costs associated with activities that are "directly related to existing or proposed core operations and undertaken to benefit its ratepayers" *ISO New England Inc.*, 117 FERC ¶ 61,070 at P 48 (2006), *order on reh'g*, 118 FERC ¶ 61,105 (2006), *reh'g denied*, 120 FERC ¶ 61,122 (2007). Further, the Commission has established a high bar for challenges to prudence of costs proposed to be recovered by utilities. When reviewing prudence, the Commission looks to whether the proposed recovery includes "costs which a reasonable utility management [] would have made, in good faith, under the same circumstances, and at the relevant point in time." *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985). Challenges to such costs must be more than bare allegations and require direct evidence to establish a serious doubt of prudence. *See, e.g., Iroquois Gas Transmission Sys., L.P.*, 87 FERC ¶ 61,295, at 62,168 (1999); *Mid-America Pipeline Co., LLC*, 124 FERC ¶ 63,016, at P 976 (2008).

been affected. Their representatives in the legislature and regulatory bodies will certainly hear from them. So the Commission should signal that project sponsors have latitude in negotiating land-use compensation, including offsets for aesthetic objections to a new transmission line, subject to the same overall test that the project benefits exceed the total costs and are projected to continue doing so. There are numerous ways in which a clever project sponsor could attempt to defuse opposition to the sponsor's project; ACEG believes the Commission should show openness to those options unless they more than offset the project benefits. And knowing that project sponsors have such latitude could be a serious incentive to state and local regulators, who could request them to use it as a mitigation measure that would permit a positive decision, instead of a preemptory rejection.

FERC should also reiterate that a transmission developer may recover in rates all the costs of performing environmental, historical, cultural, land-use, and other impact analysis required for state or local regulatory review, even if state or local authorities incur those costs. FERC should provide that any costs of reimbursing state or local bodies for their reasonable costs of hiring contractors to assist with their analysis are also recoverable. Many states and localities have budgets that cannot accommodate professional analysis costs, and could make quicker, better decisions if such analysis were performed in a timely and objective fashion. In particular, such funding could allow the full assessment of alternate rights-of-way the proposed transmission line might take, rather than merely the project sponsor's own preferred route, allowing state and local regulators the confidence that the route creating the least impact was identified to be considered as an option. Making state and local decision-makers decisions better informed can only help them reach better decisions more quickly, reducing the likelihood of negative decisions for lack of information. ACEG submits that FERC should confirm in its adopted rate policies that the costs of analysis, costs of paying for third-party support for state and local regulators, and the costs of related "public benefit" projects are all legitimate costs of project development and includable in capital costs for a project. The effect of doing so would be to create an incentive for quicker, better-informed, and more constructive state and local decision-making.

ACEG submits that the Commission should be open to suggestions from project sponsors of specific exceptions to any Commission policies the sponsors believe should be acceptable and would be helpful in removing obstacles and disincentives making state and local approvals harder to obtain. The Commission would of course maintain its standards of review of such suggestions, but its willingness to entertain them could itself be an incentive for project sponsors to proceed and explore creative ways of meeting state and local objections to their projects.

VII. Incentives Should Be Adopted to Overcome the Dramatic Lead-Time Difference Between New Transmission Line Additions and Generating Capacity Additions

One of the most significant problems the interstate electricity industry faces is the vast disparity in the lead-times required for new transmission projects and new generation projects. Although new generating capacity powered by gas, wind, or solar energy – the most economic and acceptable forms of power generation today – can generally be brought from initial proposal to on-line energy delivery within a period of two years, the lead-time from initial proposal to energizing a new transmission line is seldom shorter than seven years and frequently longer than ten. Testimony to the Commission at the time it was considering the effects of the EPA Clean Power Plan on the grid indicated that, even with full acceptance by state and local authorities, a new transmission line was likely to require seven years to complete based on requirements for right-of-way acquisition, environmental and other required analyses and actual engineering, construction and testing.[33]

The result of this disparity is a reversal of the traditional sequence of decision-making. Through most of the history of the electricity industry, a utility could begin work on a major new power plant and simultaneously or later begin work on the transmission capacity to deliver its output. Thus transmission decisions were generally derivative of prior decisions to add generation.

Now generation resources are largely subject to the effects of prior decisions about transmission. In some instances, where gas supply is available, new gas generation can be installed where existing transmission capacity exists or has been made available by the closure of an existing generating plant. But in the cases of wind and utility-scale solar generation, decisions to provide transmission transfer capacity from a given location must be made years ahead of the time it is reasonable to expect ground to be broken for the installation of new wind turbines or solar arrays.

---

[33] *See, e.g.*, Comments Submitted by Brian Parsons, Director Western Grid Group and John Jimison, Managing Director Energy Future Coalition, Docket No. AD15-4, February 25, 2015; Comments of Gerry Cauley, President and CEO North American Electric Reliability Corporation, Docket No. AD15-4, February 19, 2015.

Clearly generation developers cannot be expected to make firm transmission capacity commitments with major advance payment obligations years ahead of even beginning their own projects. Commission policy should provide a vehicle to support the development of interstate transmission facilities where the projected economic and other benefits of the resulting extension and integration of the grid are overwhelming and make the future use of the proposed capacity all but certain.

In 2005, the Texas legislature passed Texas Senate Bill 20, which ordered that the Public Utility Commission of Texas (PUCT)—in consultation with the ERCOT— designate "competitive renewable energy zones" (CREZ) and develop a transmission plan to deliver renewable power from CREZ to customers, while maintaining reliability and economics.[34] The designation of CREZ focused on large-scale wind resources that can be developed in sufficient quantities to warrant transmission system expansion and upgrades. In order to designate these zones, ERCOT contracted with AWS Truepower to determine the best wind resource zones in Texas. Based on preliminary transmission analysis and wind developer interest, the PUC identified five CREZ in 2007 and ERCOT began to develop a transmission optimization study. Ultimately, the PUCT selected a scenario that would accommodate 18.5 GW of wind at a cost of $6.8 billion and construction was initiated in 2010.

The implementation of CREZ has helped to enable the addition of more than 18 gigawatts of wind energy generation capacity to Texas's power system while overcoming technical issues such as curtailment and transmission congestion. Texas's decision to plan and build transmission for the specific purpose of developing inexpensive and abundant renewable energy in the west and delivering to load centers was a radical departure from standard practice. The overwhelming majority of transmission has been traditionally planned, approved, and built *in response to* a narrow set of pressing economic and reliability concerns – not to create an efficient and reliable network capable of reaping future economic, security, and environmental benefits. Texas's novel approach provides a helpful model for the Commission – showing how anticipatory transmission investments

[34] Public Utility Regulatory Act, TEX. UTIL.CODE ANN. §§ 11.001-66.017 (Vernon 2003, & Supp 2010-2011) (PURA) § 39.904(a).

can directly enable a timely, low-cost, and reliable portfolio of future generation that is certain to emerge but cannot finance its needed transmission years ahead of its own development.

Another key lesson of the Texas CREZ experience is that large scale transmission investments typically generate benefits far exceeding initial estimates. Texas surpassed the original CREZ target of 18 GW of wind generation capacity and is building 70% more wind capacity than initially planned. The CREZ also achieved every wind generation milestone ahead of schedule. Few predicted the magnitude of the economic benefits of the Texas CREZ Project: annual electricity production cost savings of $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. Finally, the CREZ lines are now enabling a utility-scale solar boom in Texas that was never part of the original plan. With more than 1500 MW of utility solar PV already installed, Texas was adding another 4000 MW over the next five years.

The key to the success of CREZ was commitment to build the transmission capacity, with broad cost-allocation of the anticipatory capacity across the entire ERCOT region, to be recouped by consumers over time from the delivered energy cost savings that would be enjoyed when the project was completed. The adoption of such a cost-allocation approach removed what would otherwise have been an enormous disincentive for transmission developers to have served the CREZ because there were few credit-worthy counter-parties committed to wind project development that would allow construction to start, but many such parties eager to sign them once it was sure that their generation would have a market outlet.

The presence of long queues of generators seeking transmission capacity from given regions, as noted by the NOI,[35] proves that the electricity market is hungry for a transmission policy approach that overcomes the lead-time barrier that now suppresses progress and denies consumers the economic, reliability and many other benefits they could be obtaining.

[35] Notice of Inquiry at P 31 and n. 38.

Inclusion of CWIP in rate base is an incentive that transmission developers may request under Order No. 679,[36] as the NOI itself notes in its summary of the order,[37] and in its questions about whether "Regulatory Asset/Deferred Recovery of Pre-Commercial Costs and CWIP" incentives adopted in Order No. 679 should continue. ACEG submits that they should. The Commission should reiterate that the costs eligible for early inclusion in rate base are not limited to actual construction costs, but instead include all capitalized project expenses such as costs of identifying sites, performing evaluations, dealing with land-owners and local communities, and obtaining a go-ahead from state regulators.

ACEG urges the Commission to consider other ways in which its own regulatory policies could support create incentives for approval and development of anticipatory transmission capacity into regions where there is unquestionable capacity to generate clean electricity that will doubtless be of great and increasing value over coming years and decades. If the Commission is willing as a result of this inquiry to consider creating such regulatory incentives, ACEG will eagerly participate in helping to review and refine the many options to ensure that they are both effective incentives in the public interest and fully just and reasonable and not unduly discriminatory.

VIII. Incentives are Appropriate for Installation of New Low-Cost, High-Benefit Transmission Technologies that Are Less Remunerative than Conventional Alternatives

New technologies are irrevocably changing electricity systems around the world. Those that operate on the customer side of the service meter are perhaps the most visible, offering electricity consumers the opportunity to become generators, storage operators, market participants through demand response and power quality contributions, and consumers capable of price response. Distribution systems also must embrace new technologies to manage and respond to the massive flow of digital data coming from smart meters, manage the two-way flows resulting from behind-the-meter generation, improve reliability on the part of the system from which most interruptions arise, and offer their customers the options they demand. Much less is seen and heard about the

[36] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).
[37] Notice of Inquiry at P 7.

wave of new technologies that are emerging to allow more efficient and effective use of the existing transmission system, such as dynamic line ratings, power flow controls, and others.

Despite the potential of these technologies, their novelty and uncertain lifetimes may discourage their use, especially when the conventional alternatives contribute much more to the investment rate base upon which a return on investment is calculated. Perhaps in recognition of this problem, the Commission has included questions about "Improving Existing Transmission Facilities" in Subsection 7 of the NOI.[38] The Commission further cites the failure of the Advanced Technology incentive of Order No. 679 in Section c.[39]

ACEG is allied on this issue with WATT, an ACEG coalition partner organization, which represents companies engaged in developing and implementing transmission-related technologies on existing systems, and urges the Commission to pay close attention to the detailed proposal and supporting analysis WATT will file in its comments on this inquiry. In Subsection 4 as well, addressing "Flexible Transmission System Operation," the Commission notes that "increased line rating precision, greater power flow control, and technologies, including energy storage, may be able to facilitate the transmission system's ability to respond to changing circumstances."[40] Such technologies are among the new technologies that have great potential.

Representing the entire range of transmission stakeholders, ACEG supports the concept of providing incentives based on a sharing of the savings that an investment creates in those instances where implementing a new technology is a much less expensive and provable means of achieving the same measurable gains that would otherwise be available from conventional technology at a much higher level of investment (and therefore return to the owner). When doing "the right thing" for customers by implementing a new technology would actually reduce the earnings of a transmission operator relative to electing a conventional alternative, it is fitting and proper for the Commission to ensure through rate policy that any such disincentive is neutralized or reversed.

---

[38] Notice of Inquiry at P 29, Questions 37-43.
[39] Notice of Inquiry at P 39.
[40] Notice of Inquiry at P 26.

ACEG notes that Section 219(a) of the FPA explicitly calls on the Commission to consider performance-based rate treatments in designing incentive policy.[41] ACEG submits that the improved performance such new technologies provide presents an opportunity to create performance-based incentives for implementing such technologies successfully. The savings created by the enhanced performance could potentially serve as the source of revenues from which FERC could offer the incentive, rather than adjusting the transmission operator's rate of return. The Commission, for a limited period of years, could allow the transmission provider to add a technology productivity charge to its tariff representing a fixed modest percentage of any reduction in market prices or congestion charges, depending on the market effect of the technology, before and after the implementation of the technology. ACEG believes that WATT's proposal falls within the statutory mandate of FPA Section 219 and should be considered, and that whether or not that particular proposal is deemed acceptable, that the Commission should ensure that transmission owners and operators have sufficient incentives to upgrade their technology over time when doing so is cost-effective, at a minimum ensuring that doing so does not create financial losses but instead achieves its own positive return.

IX. Comments in Response to Other Questions Posed in the NOI

Subsection 5 on "Security"[42] poses the question of whether incentives should be provided for transmission systems to enhance their physical and cyber security. ACEG submits that the security of transmission system operations is critical to every transmission segment and system, and no incremental incentive should be necessary to induce transmission owners and operators to apply effective technologies and practices to maintaining their security.

Because the state-of-the-art is constantly advancing, however, additional incentives could be warranted if a project sponsor proposes to adopt new and different security measures that promise a higher degree of security than prior projects could claim before the costs of earlier measures had been fully recovered. Such incentives could appropriately take the form of a rate-of-return adder. Cybersecurity would be defined as the persistent freedom from intrusion by hackers or any loss of

---

[41] 16 U.S.C. § 824s(a).
[42] Notice of Inquiry at P 27, Questions 32-33.

control or autonomy in digital equipment to external actors. Physical security would be defined as the physical protection and seclusion of critical equipment which if attacked and damaged could disrupt system operations for a significant period of time and the ability to respond to any physical incident quickly and effectively across the footprint of the system. If any system receiving a special security incentive in fact lost service to a cyber or physical attack, the incentive would be removed, so there would be a reason for continued vigilance over time. Such an incentive for security could readily be paired with any incentive warranted by a desire to recognize transmission system resilience, as discussed in Subsection 6.[43]

Subsection 10 of the NOI[44] poses question about transmission ownership by "non-public utilities." ACEG believes that incentives for non-public utilities to own and develop transmission capacity, perhaps jointly with private investor-owned utilities regulated by the Commission, would be appropriate, as they serve a significant portion of the public and a larger portion of the national geography, and any expansion of the integrated grid helps bulk-power markets regionally and inter-regionally, and thus helps the customers of regulated public utilities.

With regard to the "Duration of Incentives" as posed in questions in Subsection D.1,[45] ACEG concedes that there is uncertainty whenever incentives are granted about how effective they might be. If there were no such uncertainty, the Commission could just adopt the final policy in full confidence that it would achieve the intended result rather than design a policy to induce that result. The NOI itself is evidence of that uncertainty, as the Commission circles back to consider what might be done differently or better in leading stakeholders to make key transmission-related decisions and in the face of less response than was sought. In the same way that the Commission is now considering how to strengthen its policy, the Commission may at some future point consider whether its incentive policies have been too successful, have been bypassed or rendered redundant by market developments, or have need of yet further strengthening in the face of persistent underinvestment by the transmission industry despite clear public need for further investment.

[43] Notice of Inquiry at P 28.
[44] Notice of Inquiry at P 32.
[45] Notice of Inquiry at P 44.

This need for future flexibility should therefore be stated and preserved in any restatement of incentive policy, but such changes should be prospective only, and should not be applied to prior incentives upon which stakeholders relied for their actions. Once granted, a specific incentive should be retained in effect unless its removal is predetermined in its original terms. Its original terms could, for example, include a time period over which the incentive applies, but after which it is curtailed or ended. The terms could include a time period after which the incentive is no longer available, to persuade actors to move forward promptly. Specific incentives can validly be linked to the promises made by those who receive them, and if the promises are not kept, neither should the incentive be kept. But if the promise is merely to try something with an uncertain outcome, trying it is keeping the promise regardless of the outcome.

The broader and more important incentives that could be effectively created by the Commission in adjusting its regulatory policies towards transmission project planning, cost allocation, and ratemaking, would not be subject, of course, to automatic expiration or changes, but would be amended over time as necessary in the public interest. At this point, ACEG respectfully submits, the public interest justifies revisiting these policies to promote the further expansion, modernization, and integration of the nation's high-voltage power grid.

X. Conclusions

In conclusion, ACEG congratulates the Commission on taking the initiative to reopen its consideration of how its policies could be amended to provide better incentives to meet the compelling needs of the interstate transmission system. These needs are many and must be met if the nation is to achieve any of its most vital energy and environmental policy goals.

Current incentives, while offering a necessary backbone to steer investment to beneficial activities, must be supplemented with a range of policies to promote the needed new capacity, interconnections, and market improvements in a timely fashion, especially given the extreme transmission project lead times that have been experienced in this era of great local opposition activity together with divided and balkanized regulatory jurisdiction over transmission project approvals.

The Commission should examine its options in this inquiry and any following rulemaking proceedings to enhance its policies to address known obstacles to transmission development. This work should include updating incentive policies called for under Section 219 of the FPA and review of the Commission's other authorities under FPA Part II for their implicit incentives and disincentives to grid development. Modifications of Commission policies on transmission planning, cost-allocation, rate design, competition, and regional market design and functioning, among others, could be much more far-reaching and effective than simply adjusting current incentive policies. Among the opportunity targets for effective transmission policy reforms are:

- the incorporation into regional and interregional transmission planning and cost-allocation of the many currently unaccounted for benefits of transmission that consumers receive on a regional and interregional basis;
- the elimination of multiple independent planning processes for interregional projects and practical support for unified interregional project consideration;
- the recognition that while the Commission cannot eliminate current multi-jurisdictional delays and conflicting mandates, the Commission can approve policies that may diminish state and local jurisdictions' unwillingness to approve interstate transmission projects;
- the mitigation of the dramatic lead-time difference between decade-long planning, approval and construction periods for new interstate transmission projects and the two-year or shorter completion periods for the new gas, wind, and solar generating facilities that are currently favored to provide electric energy; and
- provision of incentives for deployment of modern and low-cost technologies that can improve the performance of existing transmission systems without requiring major investments.

ACEG looks forward to further opportunities to offer its views and to assist the Commission in identifying and serving the public interest in this vital domain of energy and environmental policy.

Respectfully submitted,

John W. Jimison
Executive Director
Americans for a Clean Energy Grid
3100 Clarendon Boulevard, Suite 800
Arlington, VA 22101
Office – 703-717-5596
Mobile – 202-536-8971
Email: john@cleanenergygrid.org

June 26, 2019