UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric	)	
Regional Transmission Planning and Cost	)	Docket No. RM21-17-000
Allocation and Generator Interconnection	)	

INITIAL COMMENTS OF THE EDISON ELECTRIC INSTITUTE

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I. INTRODUCTION

The Edison Electric Institute ("EEI") respectfully submits the following comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") Advance Notice of Proposed Rulemaking ("ANOPR") seeking comment on potential reforms to regional transmission planning, cost allocation and generator interconnection processes.[1]

EEI is the association that represents all investor-owned electric companies in the United States. Our members provide electricity for more than 220 million Americans and operate in all fifty states and the District of Columbia. As a whole, the electric power industry supports more than seven million jobs in communities across the United States. EEI's member companies operate in regions in all areas of the country, both inside and outside of regional transmission organizations ("RTOs") and independent system operators ("ISOs"). The electric power sector is the nation's most capital-intensive industry. EEI member companies invest more than $120 billion annually to make the energy grid smarter, cleaner, more dynamic, more flexible, and more secure to provide affordable and reliable electricity to customers. EEI's members are committed to getting the energy they provide as clean as they can as fast as they can, keeping affordability and reliability front and center.

EEI members are in the middle of a profound, long-term transformation in how electricity is generated, transmitted, and used and are well-positioned to lead the energy sector toward a climate solution. Today, 40 percent of the electricity delivered to customers comes from zero-emitting resources, including nuclear energy, hydropower, solar, and wind. As zero- or low-carbon resources are increasingly used for electric generation, greater and decarbonization are

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR").

increasingly viable goals. These changes have had a profound impact on the sector's carbon dioxide emissions, the primary GHG emissions associated with electricity production. Overall, electric power sector emissions were 40 percent below 2005 levels as of the end of 2020, their lowest level in more than 40 years.[2] These reductions will continue as nearly four dozen EEI members have announced forward-looking carbon reduction goals, more than half of which include a net-zero by 2050 or earlier equivalent goal.

With the right policies and technologies, a 100-percent clean energy future can be more than a goal. It can be a reality. Across the industry, companies are investing in a broad range of affordable, carbon-free technologies and approaches with the goal of finding the most cost-effective ways to deliver clean, reliable energy. Advancing these technologies from idea to implementation requires time and investment. EEI supports policies that provide increases in funding for the research, development, demonstration, and deployment of these technologies.

Electric transmission will play a key role in facilitating the evolution of the fuel mix for electric generation. A robust transmission system will not only enable electric utilities to integrate more renewable energy resources and deliver more clean energy to customers but will also enhance the reliability and resiliency of the grid and enable the deployment of new technologies.[3] This, in turn, will help optimize the grid's performance and lower the cost of

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[2] U.S. Energy Information Administration, Monthly Energy Review (Mar. 2021), at 203, *available at* https://www.eia.gov/totalenergy/data/monthly/.

[3] *See e.g.*, Edison Electric Institute, *The Critical Role and Value of Electric Transmission* (2019), *available at* https://www.eei.org/issuesandpolicy/transmission/Documents/2018%20Smarter%20Energy%20Infrastructure%20The%20Critical%20Role%20and%20Value%20of%20Electric%20Transmission.pdf; Edison Electric Institute, *America's Electric Companies: Serving Our Customers and Planning for the Energy Grid of the Future With Electric Transmission Technologies and Innovation* (2020), available at https://www.eei.org/issuesandpolicy/transmission/Documents/Investing%20in%20Transmission%202020.pdf; Edison Electric Institute, *Investing in Transmission to Enhance the Reliability and Resilience of the Energy Grid* (2020), available at https://www.eei.org/issuesandpolicy/transmission/Documents/Value%20of%20Transmission%20-%20Resilience%202020.pdf; Edison Electric Institute, *Electric Transmission: Enabling the Clean Energy*

delivering energy by reducing congestion which will help to keep electricity bills low for our customers. Thus, EEI appreciates the opportunity to submit comments to discuss the changes needed to facilitate transmission development going forward.

II. EXECUTIVE SUMMARY

The ANOPR seeks to address whether changes are needed to the Commission's transmission planning, cost allocation or generator interconnection processes in light of the evolving fuel mix for electric generation and growing interest in greater use of cleaner energy resources. While the improvements made by Orders Nos. 890[4] and 1000[5] have worked to improve stakeholder participation in the local and regional transmission planning processes, as discussed herein, changes are needed to some of the transmission planning processes to facilitate transmission development and generator interconnection.

With regard to transmission planning, EEI agrees with the Commission that one way to account for future uncertainty is with increased use of scenario planning that takes into consideration several plausible future outlooks with a sensitivity analysis. Given the changes that may be needed in some areas to incorporate forward looking scenario planning, the Commission should build on the aspects of the current process that are working and that will continue to be needed to provide structure, compensate for risks, and get needed transmission

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Transformation (2021), available at https://www.eei.org/issuesandpolicy/transmission/Documents/Transmission_Enabling_Clean_Energy.pdf.

[4] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[5] *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).

built. These include: (1) retaining the transparency and stakeholder participation principles outlined in Order Nos. 890 and 1000; (2) continued consideration of transmission needs driven by reliability, economics, as well as Public Policy Requirements, whether explicitly or through a coordinated integrated resource planning process ("IRP"); (3) retention of current rate policies with respect to participation in a Transmission Organization[6] and recovery of abandonment costs; and (4) continued recognition of the value of the local transmission planning process in facilitating regional development and supporting the needs of load serving entities in maintaining system resilience and reliability and meeting the needs of their customers.

While continuing these policies, if the goal is to get needed transmission built in a cost-effective, timely, and efficient manner, then the Commission should revisit aspects of Order No. 1000 that have not resulted in getting transmission built. This includes revisiting the decision in Order No. 1000 to eliminate the federal right of first refusal ("ROFR") for projects selected for regional cost allocation. This policy has resulted in a near standstill in transmission development for regional projects and a substantial increase in process-related costs. It has also stifled the cooperation and collaboration that has historically existed among transmission owners, as well as regional planning entities. It is also important to note that competitive processes are already used at every stage of transmission development and construction (e.g., engineering, materials, construction) to help ensure that rates are just and reasonable.

The transmission planning principles outlined in Order No. 890, in conjunction with the application of those principles to local and regional processes through Order No. 1000, ensures that stakeholders have an opportunity to express their needs, have access to information and an

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[6] A "Transmission Organization is a Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities. 16 U.S.C. § 796(29) (internal quotes omitted).

opportunity to provide information and to participate in the identification and evaluation of solutions. Continuation of these principles, in conjunction with reinstating the federal ROFR, will help get needed transmission built in a cost-effective, timely manner as it allows the entities with the expertise, the knowledge of the existing system, the relationship with customers and regulatory agencies and the obligation to provide safe reliable service to build the lines selected in the regional process.

With regards to cost allocation, the current approach of Commission approval of regional approaches for allocating the costs of transmission infrastructure remains appropriate. As changes are made to the transmission planning processes, some regions may re-evaluate their cost allocation processes to ensure that they allocate costs in a manner that is roughly commensurate with the benefits drawn. Relatedly, the Commission should also ensure that public utilities have the option to construct and earn a rate of return on network upgrades that they will be ultimately responsible for operating and maintaining.

Regarding interconnection, in addition to encouraging proactive planning, the Commission should focus on reforms that allow generators to demonstrate readiness based on defined criteria. The Commission should encourage transmission providers and regions to consider readiness criteria and should support approaches that prioritize certainty over flexibility in order to facilitate the interconnection process. With regards to the consideration of Grid-Enhancing Technologies ("GETs"), EEI members have made significant investments in GETs that have demonstrated improvements in efficiency, capacity, reliability, and resiliency. Going forward, GETs may play an important role in increasing efficient use of the system and providing a short-term solution until needed transmission is built. However, additional experience is needed to determine how best to model and operate these technologies.

Finally, the Commission seeks comment on whether additional transparency provisions are needed, including whether there is a need for an independent transmission market monitor or an enhanced role for the states. Order Nos. 890 and 1000 provide significant opportunities for stakeholders to receive, seek and evaluate information and to propose alternative solutions to transmission needs and to meaningfully participate in the transmission planning process. Accordingly, additional transparency provisions or a transmission market monitor that increase bureaucracy without any showing of need are not needed. In addition, states already play a significant role in the transmission planning process which is in addition to their regulatory responsibilities in overseeing public utilities. Thus, additional changes are not needed.

III. BACKGROUND

Through the ANOPR, the Commission continues its evaluation of potential changes needed to its rules and regulations to accommodate developments in energy policy and needs. In 1996, the Commission issued Order No. 888 and the accompanying *pro forma* Open Access Transmission Tariff ("OATT"),[7] which sought to implement open access to transmission facilities owned, operated, or controlled by public utilities. Order No. 888 and the *pro forma* OATT set forth certain minimum requirements for transmission planning. In particular, the *pro forma* OATT required transmission providers to account for the needs of their network customers in their transmission planning activities on the same basis as they provide for their own needs.[8] The *pro forma* OATT also required that transmission owners ("TOs") expand their

[7] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[8] *See* Section 28.2 of the *pro forma* OATT.

system to meet the transmission service requests of long-term firm point-to-point customers.[9] Order No. 888 aligned open access principles with native load priorities by allowing public utilities to reserve transmission capacity needed for native and network customer load growth reasonably forecasted in the planning horizon.[10] Order No. 888-A further encouraged, though did not require, utilities to engage in joint and regional transmission planning with other utilities and customers.[11]

The Commission issued Order No. 2003 to bring an element of standardization to the generator interconnection process.[12] Rather than evaluate interconnection issues on a case-by-case basis, the Commission crafted a standard set of generator interconnection procedures in the form of *pro forma* Large Generator Interconnection Procedures ("LGIP") and a *pro forma* Large Generator Interconnection Agreement ("LGIA"), and required that all transmission providers' OATTs incorporate the *pro forma* LGIP and *pro forma* LGIA. This standardized framework was designed to "minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[13] Order No. 2003 also defined two interconnection service products, energy resource

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[9] *See* Sections 13.5, 15.4, and 27 of the *pro forma* OATT.

[10] Order No. 888 at 172.

[11] Order No. 888-A at 272.

[12] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (*NARUC v. FERC*).

[13] Order No. 2003 at P 11.

interconnection service ("ERIS")[14] and network resource interconnection service ("NRIS").[15] These services are not discussed in the ANOPR.

In 2007, the Commission issued Order No. 890 to build on Order No. 888 by continuing to strengthen the *pro forma* OATT on issues related to undue discrimination and to provide additional specificity on the role of stakeholders in the transmission planning process. The Commission required each transmission provider to develop a transmission planning process that satisfies nine enumerated principles, and to describe the transmission planning process in Attachment K to its OATT.[16] The Order No. 890 transmission planning principles are: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[17] While noting the "difference between a planning process that is coordinated and open and one that dictates construction and cost responsibility,"[18] Order No. 890 included the requirement to study new generation resources (e.g., wind resources located in a common area that could be accessed by many customers)[19] and consistent calculation of available transfer capability that accounts for native load needs over the planning horizon.[20]

[14] Order No. 2003-A at P 535 (stating that ERIS allows access to the existing capacity of the Transmission System only on an 'as available' basis).

[15] *Id.* at P 506 (noting that NRIS is "a more comprehensive" service that provides the Interconnection Customer with the quality of transmission access needed "to compete in the energy marketplace.").

[16] Order No. 890 at P 437.

[17] *Id.* at PP 418-561.

[18] *Id.* at P 544 ("The purpose of this principle is to ensure that customers may request studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources and loads on an aggregated or regional basis (*e.g.*, wind developers), not to assign cost responsibility for those investments or otherwise determine whether they should be implemented.").

[19] *Id.* at PP 543, 548, 599.

[20] *Id.* at PP 108, 243-44.

In 2011, the Commission issued Order No. 1000 to build on the Order No. 890 reforms by requiring (1) regional transmission planning; (2) transmission needs driven by Public Policy Requirements; (3) nonincumbent transmission developer reforms; (4) regional and interregional cost allocation; and (5) interregional transmission coordination. Order No. 1000 required that each transmission provider participate in a regional transmission planning process that produces a regional transmission plan and satisfies Order No. 890's transmission planning principles.[21] The regional transmission planning process requires that transmission providers evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the region's reliability, economic, and Public Policy Requirements[22] needs in a more efficient or cost-effective manner than solutions identified in local transmission planning processes.[23] Order No. 1000 also required each transmission provider to implement methods for allocating the costs of new regional transmission facilities selected in the regional transmission plan for purposes of cost allocation, and to ensure that such allocation methods satisfy a set of six regional cost allocation principles.[24] Order No. 1000 further required that transmission providers establish processes and procedures for interregional transmission coordination.[25]

In addition, Order No. 1000 required TOs to eliminate ROFR from their Commission-jurisdictional tariffs and agreements, for projects selected for regional cost allocation, in order to allow non-incumbent transmission owners to participate in transmission planning with the same

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21 Order No. 1000 at PP 146, 148, 151.

22 Public Policy Requirements are requirements established by local, state, or federal laws or regulations (i.e., enacted statutes passed by the legislature and signed by the executive and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level). Order No. 1000 at P 2.

23 *Id.* at PP 11, 148.

24 *Id.* at PP 558, 603.

25 *Id.* at P 396.

eligibility as incumbent transmission owners to propose projects in a regional transmission plan for the purposes of cost allocation.[26] Order No. 1000 continued to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation.[27]

Through the ANOPR, the Commission seeks comment on whether changes are needed to its orders establishing transmission planning, generator interconnection and cost allocation requirements to further integrate renewable resources and interconnect new technologies to the grid.

IV. COMMENTS

As discussed above, over the years, the Commission has required reforms to the ways in which transmission providers interconnect resources and provide access to the transmission system, as well as the manner in which transmission providers plan to meet public policy and other goals. The ANOPR continues this trend and presents potential reforms to the established policies and regulations to address and reflect changing public policy needs, as well as new technologies. Specifically, the ANOPR seeks to make changes to address the evolving fuel mix for electric generation and anticipated greater use of cleaner energy resources. EEI supports the Commission's examination of these issues and notes that a number of the proposals raised in the ANOPR: (1) have already been incorporated and are working well -- such as the Order Nos. 890 and 1000 changes that encouraged stakeholder involvement and transparency, or (2) are being discussed in one form or another in some regions, such as changes to interconnection rules.

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[26] *See Id.* PP 253-257.

[27] *Id.* at P 262.

As a general overlay, EEI notes that while the ANOPR focuses on the changes for planning to facilitate the identification and construction of needed transmission and to ensure appropriate cost allocation, the ANOPR does not specifically seek comment on the reliability and resiliency aspects of its proposals. Going forward, the Commission should ensure that reliability and resiliency considerations remain front and center as it considers the proposals in the ANOPR. Each passing severe weather event is a reminder that our policy goals and objectives are only valuable if they result in safe and reliable delivery of electricity needed to serve customers. This includes ensuring that the public utilities charged with keeping the lights on have appropriate situational awareness of generation resources operating in real time so that they may safely perform their critical functions.

A. Transmission Planning

The transmission planning process has worked to identify necessary upgrades and expansion of the transmission system while cost-effectively maintaining reliability and accommodating new generation and/or load growth. EEI appreciates the Commission's goal of building the transmission necessary to meet the anticipated future generation needs of load and to connect clean energy resources. While existing regional and local transmission planning already considers a long-term view of needs, which is balanced by the need for reliable assumptions for planning purposes, EEI agrees with the Commission that one way to account for future uncertainty is with increased use of scenario planning that takes into consideration several plausible future outlooks with a sensitivity analysis. Variables incorporated into scenario planning could include, for example, public policies, renewable generation, generation retirements, load growth, resilience needs, the evolving resource mix, electrification, storage capabilities, new technologies, demand-side resources, and state zero carbon and clean energy procurement goals, and investment in non-wires alternatives. This type of planning also can incorporate longer planning horizons and the needs of states. While scenario planning plays a role in informing regional planning, it can also play a vital role in identifying inter-regional and multi-regional transmission needs. There must also be a balance in planning that attempts to identify projects that once built will be needed and used. To promote efficiency, EEI suggests that the Commission identify what is working in regional processes, discuss how best to develop transmission with the Federal /State Task Force on electric transmission,[28] and identify where hurdles exist in getting needed transmission built prior to proposing reforms.[29]

While changes may be needed to more fully incorporate scenario planning going forward, there are many aspects of the current transmission planning process that should be retained. The current regional transmission planning process, whether explicitly or through a coordinated IRP, considers transmission needs driven by reliability,[30] economics,[31] and Public Policy Requirements.[32] These categories reflect the needs that are, and that will continue to be addressed by the transmission planning process. Any changes made to the transmission planning process should ensure that reliability of the system remains a primary goal of the process. Thus,

[28] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224, at P 1 (2021)(establishing a Joint Federal-State Task Force on Electric Transmission).

[29] *See* ANOPR at P 63 (inquiring about barriers to effective interregional planning and potential corrective action by the Commission).

[30] Reliability projects are proposed when reliability standards are projected to be violated.

[31] Economic projects are proposed not because reliability standards are violated, but because there is an economic benefit such as relieving congestion or providing access to lower cost energy.

[32] Order No. 1000 brought public policy goals into the planning process by requiring public utility transmission providers to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes. For purposes of these comments, "Public Policy Requirements" has the same definition as that used by the Commission in Order 1000 ("consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations (Public Policy Requirements). By 'state or federal laws or regulations,' we mean enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level."). Order No. 1000 at P 2.

in addition to a transmission planning process that evaluates long term transmission needs based on a number of potential drivers such as economics, anticipated generation/interconnection, reliability,[33] diversity, resiliency, and public policy,[34] among others, there should continue to be a planning process to identify near-term (i.e. 5 years or less) regional and/or local reliability needs, and transmission projects needed to relieve congestion from existing or known generation projects.

While scenario planning should be incorporated into the long-term transmission planning, the Commission should continue to take a flexible approach[35] and should not impose prescriptive regulations dictating how those scenarios are developed, particularly given significant regional differences. Transmission providers, in coordination with TOs, load serving entities and states, should continue to be the ones who develop the planning assumptions needed to incorporate scenario planning into the transmission planning process.[36] Consistent with the Commission-approved transparency requirements, all stakeholders should continue to have the opportunity to review the planning assumptions and provide input.[37]

In addition to ensuring that reliability remains first and foremost, the Commission should ensure that any reforms to the regional/inter-regional transmission planning processes do not

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[33] The long-term planning process should not be required to solve all potential reliability needs given the future uncertainty and the existence of the short-term reliability planning process.

[34] Public Planning Requirements should be included in the planning models, and there does not need to be a separate public policy planning process.

[35] *See, e.g.,* Order No. 1000-A at P 266 (explaining that the Commission believes "that Order No. 1000 sets forth an approach that balances the need to ensure that specified regional transmission planning requirements are satisfied with our belief that the various regions of the country differ significantly in resources, industry organization, market design, and other ways so that a one-size-fits-all approach to regional transmission planning would not be appropriate.").

[36] For example, in California, the California Public Utilities Commission transmits a base case and two sensitivity portfolios to the CAISO to be studied in the annual Transmission Planning Process.

[37] *See* Order No. 890 at P 454.

compromise the ability to continue to effectively address local planning needs. In Order No. 1000, the Commission recognized the value of the local planning process. The Commission indicated that when a

> public utility transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission alternatives that are proposed and then develops a local transmission plan that identifies what transmission facilities are needed to meet the needs of its native load (if any), transmission customers, and other stakeholders. Through this process, the public utility transmission provider evaluates the various alternatives available to determine a set of solutions that meet the system's needs more efficiently or cost-effectively than other proposed solutions.[38]

The Commission further recognized the role of a public utility in meeting its reliability and service obligations to its customers, and in Order No. 1000 declined to "remove or limit any right an incumbent may have to build, own and recover costs for upgrades to the facilities owned by an incumbent," or alter a public utility's use and control of its existing rights-of-way.[39]

The local transmission planning process continues to result in local projects being built that are not only needed to meet local needs but also to maintain the reliability and resilience of the transmission grid as a whole. This is especially important given the penetration of renewable generation resources. Local transmission is not in lieu of regional transmission; it addresses local customer needs, including increased solar penetration, growth of electric vehicle ownership, and potential battery storage advancements, among other grid of the future developments. The local transmission planning process facilitates regional development and supports the needs of load serving entities to maintain system resilience and reliability and meet the needs of their customers. To illustrate this point, the first 100 miles of high-voltage

[38] Order No. 1000 at P 79 (internal footnote omitted).

[39] *Id*. at P 319.

transmission from a generator will mean nothing if the last 10 miles of local transmission are not built.

In addition, Order No. 1000 requires public utility transmission providers to participate in a regional transmission planning process that evaluates regional level transmission alternatives that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. Order No. 1000 states that

> [t]hrough the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. This could include transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirement discussed further below. When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed non-transmission alternatives on a comparable basis.[40]

Thus, the fact that a project is a local project does not diminish the level of stakeholder review or transparency. This review includes an evaluation of whether a regional project may be a more efficient or cost-effective solution to the identified problem.[41] The Commission has recognized

[40] *Id*. at P 148.

[41] For example, Attachment M-3 of PJM Interconnection LLC's ("PJM") OATT outlines the review process for supplemental projects in PJM. *See* PJM, *PJM Transmission Owners Attachment M-3 Process Guidelines*, https://www.pjm.com/-/media/planning/rtep-dev/pjm-to-attachment-m3-process-guidelines.ashx (last visited Oct. 6, 2021); PJM OATT, Attachment M-3, *available at* https://agreements.pjm.com/oatt/31552. . In approving Attachment M-3, the Commission indicated:

> The Supplemental Projects planning process established in Attachment M-3, with the revisions directed in the February 15 Order, provides for separate meetings for stakeholders to review and discuss the assumptions that the PJM Transmission Owners use to plan and identify Supplemental Projects, the identified criteria and system needs that may drive the need for Supplemental Projects, and potential solutions and alternatives to meeting those needs. The process further prescribes time periods for stakeholders to review materials and provide comments which . . . we find to be sufficient to comply with Order No. 890. We confirm that this

that this process provides "additional transparency [that] will help mitigate concerns that Supplemental Projects may be structured to avoid or replace regional transmission projects that would otherwise be subject to competitive transmission development under Order No. 1000."[42]

The Commission's goal should be to have the planning processes proactively identify transmission needs at the regional level and ensure that regional planning considers the appropriate drivers of transmission for that region, e.g., customer demand for clean energy and state and local laws, goals, and regulations. This will result in the identification of cost-effective transmission. If the Commission's goal is to build needed transmission in a timely and efficient manner, then as discussed below, rather than make changes to the process for development of local projects, the Commission should reinstate provisions in tariffs and agreements that established a federal ROFR that were removed by Order No. 1000.[43]

1. Reinstating the Federal ROFR

Through the ANOPR, the Commission seeks comment on whether changes are needed to its transmission-related regulations in light of the continued evolution of the fuel mix for electric generation and the need to accommodate the growth of new resources seeking to interconnect to the transmission system. In some instances, renewable generation will be located far from load centers. In other instances, renewable generation might be located closer to load centers. In both scenarios, there are and will be identified transmission needs.

process ensures that the Supplemental Projects planning process in PJM complies with Order No. 890, including by providing sufficient transparency to stakeholders regarding the basic criteria, assumptions, and data that underlie their transmission system plans and ensuring appropriate lines of communication between stakeholders and the PJM Transmission Owners. (*Monongahela Power Co*., 162 FERC ¶ 61,129 (2018), *order on reh'g*, 164 FERC ¶ 61,217 (2018), at P 30 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 454, 461, 471)).

[42] *Monongahela*, 162 FERC ¶ 61,129 at P 108.

[43] *See* Order No. 1000 at PP 253, 313 (directing the elimination of the federal ROFR).

Public utilities working with or at the direction of the states have developed transmission and continue to plan transmission needed to meet the needs of the changing resource mix and to achieve carbon reduction goals. These include, for example, the New Jersey Board of Public Utilities' transmission solicitation to connect to offshore wind resources,[44] Greenlink Nevada,[45] Energy Gateway,[46] and New York State Public Service Commission's Public Policy Transmission projects.[47] Additionally, states and utilities have a track record of successfully partnering to build large scale projects that facilitate delivering resources to load, such as: (1) Mid-Continent Independent System Operator's ("MISO's") Multi-Value Project Portfolio, (2) Southwest Power Pool's Balanced Portfolio,[48] (3) the Tehachapi project in the California Independent System Operator,[49] and (4) the Competitive Renewable Energy Zone[50] lines in the Electric Reliability Council of Texas. These projects demonstrate that significant projects can be built when there is alignment on need and cost allocation. It should also be noted that MISO's Multi-Value Projects were developed prior to Order No.1000 requirements. These projects

[44] State of New Jersey Board of Public Utilities, *NJBPU Announces Major Step Forward in Offshore Wind Goals with Launch of First-of-its-Kind Competitive Solicitation* (April 15, 2021), *available at* https://www.bpu.state.nj.us/bpu/newsroom/2021/approved/20210415.html.

[45] Order of Public Utilities Commission of Nevada, *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fourth amendment to its 2018 Joint Integrated Resource Plan to update and modify the renewable portion of the Supply-Side Action Plan and the Transmission Action Plan*, Docket No. 20-07023 (March 22, 2021).

[46] *See* PacifiCorp, *Energy Gateway*, https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html (last visited Oct. 6, 2021).

[47] *See* New York Independent System Operator, *NYISO Board Selects Transmission Projects to Meet Public Policy Need* (April 8, 2019), *available at* https://www.nyiso.com/-/press-release-nyiso-board-selects-transmission-projects-to-meet-public-policy-need.

[48] *See Southwest Power Pool, Inc.*, 125 FERC ¶ 61,054 (2008); *order on reh'g and compliance*, 127 FERC ¶ 61,271 (2009); *order on reh'g and compliance*, 137 FERC ¶ 61,227 (2011).

[49] *See* Southern California Edison, *Tehachapi Renewable Transmission Project*, https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11 (last visited Oct. 6, 2021).

[50] Order on Rehearing of Public Utility Commission of Texas, *Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*, Docket No. 33672 (Oct. 7, 2008).

demonstrate that regions can build needed transmission without prescriptive planning regulations. Despite these projects, there is concern that the transmission planning and cost allocation requirement reforms adopted in Order No. 1000 have resulted in development of local projects but have not consistently resulted in the development of large regional and inter-regional transmission facilities. To that end, the Commission seeks to better understand how elimination of the federal ROFR in Order No. 1000 has shaped the type and characteristics of facilities developed through regional and local planning processes.[51]

In Order No. 890, the Commission required public utility transmission providers to have in place processes for evaluating the merits of proposed transmission solutions offered by potential developers,[52] and subsequently required public utility transmission providers to include in their OATTs language that identifies how they will evaluate and select among competing solutions and resources.[53] In Order No. 1000, the Commission took this a step further and found that the federal ROFR deprives customers of the benefits of competition in transmission development and associated potential savings.[54] While the Commission retained the federal ROFR for immediate need projects and upgrades to an incumbent TO's transmission facilities and did not alter an incumbent transmission provider's use and control of its existing rights-of-way,[55] the Commission removed the federal ROFR for transmission facilities selected in a regional transmission plan for purposes of cost allocation.[56]

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[51] ANOPR at P 37.

[52] *See* Order No. 890 at P 494; Order No. 890-A at P 215-16.

[53] *See, e.g.*, *New York Independent System Operator, Inc.*, 129 FERC ¶ 61,044 (2009), at P 35.

[54] Order No. 1000 at PP 284-285. [55] *Id.* at P 319.

[55] *Id.* at P 319.

[56] *Id.* at P 313.

In determining that it had the authority to remove the ROFR from federal tariffs, the Commission indicated that the inability of transmission providers to provide alternate solutions "is unjust and unreasonable because it may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, the inclusion of higher-cost solutions in the regional transmission plan."[57] The Commission went on to say that the "federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential saving.…"[58] As discussed below, rather than resulting in lower rates and increased transmission build, the removal of the federal ROFR has resulted in uncertainty, increased costs and increased delays.

Competitive processes for transmission projects have had the natural effect of stifling the cooperation and collaboration that has historically existed between transmission owners, as well as regional planning entities as stakeholders have become competitors and independent planning entities have become neutral administrators of competitive solicitations. This approach to transmission development does not foster collaboration and is not focused on the best interest of the customer. The cooperation and collaboration that exists between neighboring TOs was and continues to be an important component of ensuring a coordinated planning process that focuses on the benefits to customers through shared data and transmission solutions. Collaboration among those with planning expertise is critical to building transmission in a timely and efficient manner and will be instrumental in developing the grid of the future.

The elimination of the federal ROFR has not been shown to produce the benefits ultimately underlying the Commission's rationale for removal nor the goals that the Commission

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[57] *Id*. at P 284.

[58] *Id*. at P 285.

is pursuing in the instant proceeding. Rather, the policy has made it more difficult and costly to plan regional transmission solutions and has increased the possibility of litigation. These factors result in delays and added costs. In general, significant time and effort are involved in opening solicitation windows, allowing time for proposal development and submission, reviewing proposals, project selection, and exhausting all challenges to a project selection.[59] As implemented by some regional processes, the resources needed to evaluate multiple proposals (estimated to take between 133 and 1,498 days when there is more than one bidder)[60] increase time and costs while exposing projects to possible litigation.

On the other hand, the success of the exemption from competition for immediate need and local projects in getting transmission built is evident. The capability of incumbent TOs to expertly and efficiently build transmission helps address not only local issues, but also serves to facilitate the timely and efficient development of regional projects. Removing the prohibition on including the ROFR in federal tariffs for all regional projects will allow those projects to get built in a timely, efficient, and cost-effective manner, similar to local projects. Public utilities also have an obligation to provide safe, adequate, and reliable service at just and reasonable rates, which includes exercising cost discipline in building transmission facilities—through, for example, competitive solicitations for equipment, construction, and labor. Thus, competitive processes have always been in place in the development process to ensure just and reasonable rates. In addition, public utilities have the necessary relationships with their state regulators to

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[59] *See e.g.,* Concentric Energy Advisors, *Building New Transmission, Experience to Date Does Not Support Expanding Solicitations* (June 2019), available at https://ceadvisors.com/publication/building-new-transmission-experience-to-date-does-not-support-expanding-solicitation/.

[60] *Id* at 37.

help meet public policy goals, and some energy companies are already working with their states to incorporate public policy criteria into their planning processes.

Reinstating the federal ROFR will address the inefficiencies caused by the competitive process and help get needed transmission built in a cost-effective, timely manner as it allows the entities with the expertise, the knowledge of the existing system, the relationship with customers and regulatory agencies and the obligation to provide safe reliable service to build the lines selected in the regional process. Customer engagement and input is critical in the developing and siting infrastructure projects. Public utilities have a relationship with and an obligation to their customers and hold numerous open houses and information sessions in their communities. This outreach provides them with a unique understanding of community needs and objections to help site transmission with the least environmental and community impacts. Economies of scale are also an important component of reducing costs and creating efficiencies. Entities that have the responsibility of providing safe, reliable service have the inventory of spare parts, adequate field personnel, existing emergency management capabilities and restoration equipment to construct, maintain, and repair transmission infrastructure, to expedite construction and restoration of service safely and reliably. As severe weather events and cyber-and physical attacks become more frequent, the ability to restore power quickly and reliably has become increasingly important. Public utilities have entered into partnership with utilities across the country committed to helping restore power whenever and wherever assistance is needed.

In removing the ROFR from federal tariffs, the Commission was concerned about undue preference in building lines and lack of stakeholder review. The transmission planning principles outlined in Order No. 890 in conjunction with expanding and applying those principles to local and regional processes through Order No. 1000 helps ensure that stakeholders have an opportunity to express their needs, have access to information and an opportunity to provide information and to participate in the identification and evaluation of solutions. The issue appears to be that despite this input, the transmission is not being built. Reinstating the federal ROFR will address this issue as it will remove the complex and costly competitive processes and allow public utilities experience, expertise, relationships, with the obligation to build cost-effective transmission projects in a timely manner.

2. Scenario Planning

While retaining existing processes associated with near-term reliability and economic planning principles, EEI supports a more holistic approach to long term planning that, for instance, includes expected future/projected generation in resource plans reasonably anticipated to meet the needs of load. With the changing resource mix and the faster timeline for developing renewable resources compared to the timeline for developing associated transmission, Commission policy should encourage long term planning to build transmission that (1) allows access to resource rich areas, (2) maintains reliability with load and resource variability and (3) optimizes diversity, consistent with the resource needs of customers. This would support a process that identifies needed larger projects, including inter- and multi-regional transmission, that provide a combination of benefits. Given regional differences in voltage levels and diversity of resources, the Commission should not mandate levels at which projects are selected for broader cost allocation and should allow regions to determine the projects that are appropriate for broader cost allocation.[61] This includes how to address benefits that may be hard to quantify.

[61] *See* ANOPR at P 59.

The Commission seeks comment on what factors shaping the generation mix are appropriate to use for transmission planning purposes, such as: (1) federal, state, and local climate and clean energy laws and regulations; (2) federal, state, and local climate and clean energy goals that have not been enshrined into law; (3) public utility and corporate energy and climate goals; (4) trends in technology costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; and, (5) resource retirements and whether the Commission should establish minimum requirements regarding future scenarios for transmission providers to use in their regional transmission planning.[62] While all of these factors may be appropriately considered, different regions have different public policies and risk factors to consider, and the Commission should allow for regions to determine the emphasis to provide based on regional and local needs. Accordingly, the Commission should provide this list as guidance for regions to use in determining the factors to use in scenario planning. The Commission should not require but allow regions to make greater use of probabilistic transmission planning approaches, as appropriate.[63]

Rather than imposing one-size-fits all requirements, the Commission should consider developing guidelines or criteria for regions to consider as they develop their processes and allow regions to have flexible processes that can adapt to regional needs and challenges. As regions consider forward looking scenario planning, transmission planners in consultation with the states and other stakeholders could evaluate the potential for clean energy zones to facilitate integration of renewable resources.[64] More proactive planning criteria could also reflect the need for geographic diversity of resources or diversity of resource type. This would include issues

[62] *See Id.* at P 46.

[63] *See Id.* at PP 48-49.

[64] *See Id.* at P 54.

related to extreme weather events and other issues related to climate change. Since each region has unique characteristics and attributes, the planning regions should retain the flexibility to coordinate and determine the criteria for any scenario and sensitivity analyses.

Finally, states play an integral role in regulating the siting, permitting, and constructing of transmission lines. Going forward, effective federal-state coordination will play an increasingly important role in ensuring that needed inter-regional and multi-regional transmission infrastructure is developed and built in a timely manner. As discussed in Section D, while additional state oversight measures are not needed, communication and collaboration between state and federal regulators is and will be critical. Given the necessary cooperation needed to develop transmission facilities, forums, such as the newly created joint federal-state task force on electric transmission, will help ensure communication and an exchange of ideas and concerns.[65]

3. Proposed Changes to Existing Commission Rate Policies

The Commission seeks comment on whether two of its existing policies should be changed to accommodate the proposals in the ANOPR, namely the incentive for participation in a RTO/ISO (the "Transmission Organization Participation Incentive")[66] and the recovery of prudently incurred abandoned plant costs. In short, the Commission should avoid making changes the changes to these policies as proposed in the ANOPR.

The Commission proposals in the ANOPR add complexity and increased risk to the transmission planning process with the use of scenarios and probabilistic planning. The array of ideas and proposals offered in the ANOPR increase the regulatory risk associated with transmission development. For example, the Commission desires transmission planners take a

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[65] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61, 224 (2021) (Order Establishing Task Force and Soliciting Comments).

[66] 16 U.S.C. § 824s(c) stating that "the Commission *shall* provide incentives to each utility that joins a Transmission Organization." (emphasis added).

longer and broader view of transmission needs but expanding the planning period could result in more speculative transmission projects being developed. Increased risk for transmission developers is inconsistent with limiting the applicability of the equity adder for RTO/ISO participation and with changes to the Commission's long-standing policy regarding recovery of abandoned plant. At a minimum, the Commission should recognize this added complexity and retain its existing policies as the proposals in the ANOPR increase, rather than decrease, the burdens, and risks for public utilities. Accordingly, the Commission should not modify either the incentive for participation in a RTO/ISO or for recovery of prudently incurred abandoned plant costs.

In addition, the Commission is proposing that transmission planners take a longer and broader view of transmission needs and to plan to those anticipated needs. This injects an additional layer of assumptions into the transmission planning process. To provide regulatory certainty, the Commission should explicitly state that transmission projects built in anticipation of future generation through a transmission planning process will not be subject to after-the-fact prudency reviews.

a. Transmission Organization Participation Incentive

Highlighting the Commission's concern that larger lines are not being built under the current transmission planning process, the Commission seeks comment on whether any available return on equity adder incentive for participation in an RTO/ISO should be limited in applicability only to regional, and not local, transmission facilities, when those regional transmission facilities are selected as the more efficient or cost-effective solution to an identified transmission need.[67] This proposal misconstrues the purpose of the incentive for joining and remaining a member of an RTO/ISO.

In 2005, Congress amended section 219 of the Federal Power Act ("FPA") to require that the Commission establish by rule incentive-based rate treatments for public utilities. Specifically, Congress directed that the Commission *shall* provide incentives to each public utility that joins a Transmission Organization.[68] Thus, the statute, without limitation, requires that the Commission provide incentives to each public utility that joins a Commission-approved RTO or ISO.

In Order No. 679, the Commission approved "requests for ROE-based incentives for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization."[69] At the time, the Commission recognized the value of providing the incentive for remaining in a Transmission Organization and clarified that "entities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive."[70] In Order No. 679-A, the Commission reaffirmed its rationale. The Commission noted that section 219 specifically indicates that the Commission shall provide incentives to each transmitting utility or electric utility that joins a Transmission Organization and that providing an inducement for utilities to

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[67] ANOPR at P 61.

[68] 16 U.S.C. § 824s(c).

[69] *Promoting Transmission Investment through Price Reform,* Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 at P 326 (2006) ("Order No. 679").

[70] *Id*. at P 331.

join, and remain in, Transmission Organizations is entirely consistent with the broader goals of section 219.[71]

The Commission's proposal that the incentive only apply to a subset of projects such as those selected in a regional plan, is inconsistent with the statute and Commission precedent. Congress spoke unequivocally that the Commission shall provide an incentive to all utilities that join a RTO/ISO. Congress did not give the Commission discretion to eliminate the incentive or limit its application to some (but not all) utilities that join a Transmission Organization. Insofar as special projects need additional incentives, the Commission has other tools available that it can use to incent specific projects and has initiated a rulemaking process on the issue.[72] The existence of those other tools has no bearing on the Commission's nondiscretionary duty under Section 219 to provide an incentive to utilities that join a Transmission Organization. The Transmission Organization Participation Incentive must apply to all utilities that join a Transmission Organization for the duration of their membership without limitation and is not related to specific transmission or other projects. Congress determined that this incentive is necessary, and the Commission cannot adopt a policy that contradicts the statute.

b. Abandoned Plant

The Commission also seeks comment on whether it should revisit it policies regarding abandoned plant to protect consumers.[73] The Commission indicates that, "[f]or example, one proposal to protect consumers would be to limit the recovery of costs through abandonment by

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[71] *See Promoting Transmission through Price Reform,* Order No. 679-A, 72 Fed. Reg. 115211 at P 86 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,235 (2007) (internal footnote omitted).

[72] *See e.g., Elec. Transmission Incentives Policy under Section 219 of the Fed. Power Act, Supp. Notice of Proposed Rulemaking*, 85 FR 18784 (Apr. 26, 2021), 175 FERC ¶ 61,035; and *Elec. Transmission Incentives Policy under Section 219 of the Fed. Power Act*, Notice of Proposed Rulemaking, 85 FR 18784 (Apr. 2, 2020), 170 FERC ¶ 61,204, *errata notice*, 171 FERC ¶ 61,072 (2020).

[73] *See* ANOPR at P 178.

allowing only the recovery of some portion of actual development or pre-commercial costs, and/or no recovery of a return on equity on such costs prior to the project receiving all necessary regulatory approvals."[74]

Currently, the Commission, recognizes the risk associated with transmission development and allows for recovery of the costs of abandoned plant under section 205 of the FPA. A public utility may recover up to 50 percent of prudently incurred costs incurred before the date of the order granting recovery of abandoned plant costs.[75] In Order No. 679, the Commission found that allowing applicants to seek recovery of 100 percent of prudently-incurred costs associated with abandoned transmission projects when such abandonment is outside the control of the public utility is an appropriate incentive to encourage transmission development by reducing the risk of non-recovery of costs.[76] Prior to permitting a public utility to include these costs in transmission rates, the Commission requires that the public utility make a section 205 filing to ensure the prudency of the costs and to prevent double recovery.[77] Thus, today, public utilities can recover 50 percent of prudently incurred costs before an order is granted and 100 percent of the costs incurred after the order is granted.

These abandonment policies should appropriately recognize the risk associated with building transmission which will increase if the proposals in the ANOPR are enacted. Currently, there are numerous circumstances that can cause a project to be abandoned that are outside of a public utility's control. These include denial of permits (by state, federal, or local authorities),

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[74] *See Id.* at P 179.

[75] *New Eng. Power Co.*, Op. No. 295, 42 FERC ¶ 61,016, at 61,081-82, *order on reh'g*, Op. No. 295-A, 43 FERC ¶ 61,285 (1988). *See also*, *San Diego Gas & Elec. Co. v. FERC*, 913 F.3d 127 (D.C. Cir. 2019) (upholding FERC's decision that only costs incurred after the date of a Commission order on the request for abandoned plant incentive are eligible for 100 percent recovery).

[76] Order No. 679 at P 163.

[77] *Id.* at P 166.

inability to obtain rights of way, changes in federal or state policies that occur during the permitting process (e.g., environmental or wildlife regulations), delays in federal or states' siting schedules, and changes in transmission needs, among others. These risks will continue and increase as at the core of the ANOPR is the idea that transmission planners, entities, and stakeholders should (and may be directed to) examine a variety of new, and difficult to estimate, planning drivers over much longer timeframes than are currently used and understood. This introduces new uncertainties and risks into the transmission planning process. The Commission's proposal to "limit the amount that can be recovered for regional transmission facilities that are abandoned before going into service" is fundamentally inconsistent with the increase in development risk contemplated by the ANOPR's new ideas. Moreover, retention of the abandoned plant is also consistent with section 219 of the FPA which states the goals of the Commission's incentives policy include promoting "capital investment in the enlargement, improvement, maintenance and operation of all electric transmission facilities."[78]

In the Incentives NOPR, the Commission appropriately recognized that the abandoned plant policy, along with other non-ROE incentives, are vital in facilitating the investment in and development of transmission projects as they remove regulatory barriers and other impediments to investment.[79] Moreover, the Commission recognized the changes and increasing complexity in transmission planning since the issuance of Orders Nos. 679 and 1000 and in the Incentives NOPR, proposed to change the start of the effective date for the incentive from the date that the Commission issues an order granting 100 percent recovery of abandoned plant costs to the date that transmission projects are selected in a regional transmission planning process for the

[78] 16 U.S.C. § 824s(b)(1).

[79] Incentives NOPR at P 38.

purposes of cost allocation.[80] Given the changes proposed in the ANOPR, the Commission should not only refrain from removing its policy for recovery of abandoned plant costs as proposed in the ANOPR, but expand it as proposed in the Incentives NOPR. This will provide regulatory certainty that prudently incurred costs for projects selected through a regional transmission planning process will be recoverable.

B. Cost Allocation

In Order No. 1000, the Commission required that the costs of transmission infrastructure must be allocated to its beneficiaries in a manner that is at least roughly commensurate with the benefits that they draw from those facilities.[81] Current Commission approved approaches for allocating the costs of transmission infrastructure generally strive to allocate the costs of those transmission facilities to the entities that ultimately benefit from them.[82] As changes are made to the transmission planning processes, some regions may re-evaluate their cost allocation processes to ensure that costs are allocated in a manner that is roughly commensurate with the benefits drawn.

The Commission is concerned that the failure to account for all the benefits of a transmission facility while taking into account all the costs of the transmission facility does not allow for a fair examination of whether the costs are allocated roughly commensurate with the benefits.[83] Proactive scenario planning can consider those benefits, as well as others given the particular projects or portfolio of project. Finding the set of regional projects that provide customer benefits and have support of customers and regulators is the path forward. The

[80] *Id.* at P 84.

[81] *See* Order No. 1000 at P 622.

[82] *See* ANOPR at P 77.

[83] *Id.* at P 84.

Commission should not limit the types of projects or require that all types of benefits be considered for a given type of project. Additional discussion is needed before requiring regions to include hard to quantify benefits in the cost allocation process to determine the best way to quantify qualitative benefits.[84] In addition, in other regions, such as those with a significant number of non-jurisdictional entities, like the NorthernGrid and WestConnect regions, the complexities of regional planning through an Order No. 1000 process create other planning and cost allocation issues.[85] How benefits are determined and allocated will continue to vary between regions, and the Commission should allow the regions to make these determinations.

1. Cost Allocation for Facilities Planned Through Regional Process

Cost allocation for regional projects should continue to use Commission-approved cost allocation methodologies. The Commission should encourage regions to consider the full range of benefits that transmission investments can provide and not understate demonstrated value of such projects and how these values change over time. The benefits used in the regional processes today should continue to be used going forward and, if needed, be expanded by the region as appropriate. Additional benefits that regions could consider if appropriate include the benefits of diversity, resiliency, and adequacy as well as economic benefits. In addition, while being careful to avoid speculative accounting, transmission planners could, for example, consider the risk-mitigation and option value of transmission infrastructure that can avoid the potentially high future costs of an insufficiently robust and flexible transmission

[84] *See Id.*

[85] *See e.g.*, *El Paso Electric Company v. Federal Energy Regulatory Commission*, 832 F.3d 495, 500-01, 506-08 (5th Cir. 2016).

grid.[86] Additional guidance from the Commission could be helpful in helping regions understand Commission objectives regarding benefits and beneficiaries.

The Commission should ensure that cost allocation remains roughly commensurate with benefits, while ensuring that customers and load serving entities are protected from cost shifting. Importantly, proactive regional planning discussed above will help to ensure transmission needs are met efficiently and cost effectively. For example, in some RTO/ISO regions changes may be needed to address how costs are allocated to generators selecting ERIS as opposed to NRIS. Unlike NRIS resources or resources associated with firm transmission service, ERIS resources are generally not required to incur the same level of network upgrades costs and are typically excluded from deliverability studies.[87] However, when ERIS resources are included in reliability planning power flow studies, it may result in the identification of projects, the cost of which would be borne by customers other than the ERIS resources. Additionally, cost shifting to others can also result when the full set of North American Electric Reliability Corporation ("NERC") contingencies are studied, resulting in later-identified projects and additional costs that are not borne by the ERIS resource. When the output of these ERIS resources is included in future economic transmission planning studies, that inclusion often drives up congestion within the planning models which, in turn, tends to drive the need for economic projects paid for by existing transmission customers. Failing to completely address these and associated issues will continue the very type of undue cost shift to customers that the Commission expresses concern about in the ANOPR.

[86] *See* ANOPR at P 70.

[87] ERIS customers may simultaneously or later request firm transmission service at which time deliverability to an identified load is assessed and the costs of network upgrades assigned. However, in some RTOs, such as SPP, ERIS resources are not required to be associated with a firm transmission service reservation and many are not.

2. TOs Right to Build and Earn a Return on Network Upgrades

Order No. 2003 established cost allocation mechanisms for network upgrades.[88] Any changes to the Commission's cost allocation between generation developers and transmission customers and ultimately end-use customers need to ensure that generators continue to have the appropriate incentives to make responsible siting decisions and that local customers are not disproportionately cost-impacted by the siting decisions of generation developers.

As the Commission considers whether changes are needed, the Commission should also recognize that the direction suggested by the ANOPR envisions the potential for significant growth in network upgrades as part of interconnection queues that are already backlogged in many parts of the country. Once constructed, generators turn over control of network upgrades to TOs who then must own, operate, and maintain those facilities as part of the transmission grid. While TOs are generally able to recover operations and maintenance costs, presently, in many areas of the country, they are precluded from earning any return on those network upgrades despite having the responsibility for owning, reliably operating, and maintaining the asset for its useful life. The obligation to own, operate, and maintain these facilities comes with substantial risk including regulatory risks, reliability risks, cybersecurity risks, environmental risks, and operational risks. These risks increase commensurately with the number of generator interconnections. Under this paradigm, it is no longer appropriate to not allow TOs the opportunity to fund the capital cost of and earn a return on the upgrades necessary to

[88] For purposes of these comment, the term "network upgrades" refers to the network upgrades required to accommodate the interconnection of generators to the transmission system.

accommodate generator interconnections, particularly when this option is consistent with judicial and Commission precedent.[89]

In *Bluefield,* the Supreme Court of the United States found that, for a regulated enterprise, "[a] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public…."[90] In *Ameren,* the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") recognized the risks associated with owning and operating transmission facilities and vacated and remanded the Commission's order denying the TOs in MISO the option to self-fund. The D.C. Circuit stated,

> We therefore think that FERC inadequately considered Petitioners' argument that all costs, and risks, are not baked in—that, in fact, shareholders are forced to accept incremental exposure to loss with no corresponding benefit… it seems undisputable that when portions of a business are unprofitable, it detracts from the attractiveness to investors of the business as a whole—and that *is* a concern that the Commission must at least address under *Hope*'s capital-attraction standard.[91]

On remand, the Commission approved the self-fund provision in MISO and indicated that its previous order,

> failed to properly address transmission owners' argument that removal of the Transmission Owner Initial Funding option compels transmission owners to build, own, and operate transmission facilities on a non-profit basis. In dismissing transmission owners' arguments… the orders required them to act in part as non-profit businesses by modifying their entire enterprises, thereby creating a risk that future capital investment will be deterred….[92]

Consistent with this precedent, the Commission must not only recognize the importance of

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[89] *See also* Large Generator Interconnection Agreement, Art. 11.3 allowing TOs to build and own network upgrades, available at https://www.ferc.gov/sites/default/files/2020-04/LGIA.pdf

[90] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 692 (1923)("*Bluefield").*

[91] *Ameren Services Co. v. FERC*, 880 F.3d 571, 50-581 (D.C. Cir. 2018)("*Ameren*").

[92] *Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,158, P 32 (2018), *order on briefing, compliance and reh'g,* 169 FERC ¶ 61,233 (2019).

network upgrades to building the grid of the future as outlined in the ANOPR, but also must allow TOs the option of funding the increased development of network upgrades contemplated to ensure that the increased burdens being placed on TOs is also being appropriately compensated.

C. Interconnection

Proactive transmission planning envisioned by the Commission may help to facilitate interconnection by making transmission available in anticipation of the future generation needs of load serving entities.[93] This type of approach will help to reduce serial build, ensure efficient transmission expansion, and also help with providing cost transparency.

In addition to the focus on proactive planning, the Commission should focus on reforms that allow generators to demonstrate readiness based on defined criteria. These commercial ready projects will help facilitate the interconnection process by ensuring that generation that is ready to be installed can be in a timely and efficient manner.[94] A number of regions and public utilities have methods in their OATTs which can serve as guidelines in developing a first-ready first served process. For example, the New York Independent System Operator's ("NY ISO") reliability planning process;[95] Southwest Power Pool's Interconnection Study Agreement;[96] and Xcel Energy Operating Companies Standard Large Generator Interconnection Procedures[97] have

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[93] The anticipated generation in the long-term planning models will not be the same generation in the interconnection queue. For instance, anticipated generation in the planning models, like that driven through a state mandated IRP process, will likely be in a different location, may have different fuel types and may be of a different total MW volume.

[94] *See* ANOPR at PP 154-57.

[95] Reliability Planning Process Manual*,* New York ISO (Apr. 2021), https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf/67e1c2ea-46bc-f094-0bc7-7a29f82771de. .

[96] Southwest Power Pool, FERC Electric Tariff, (OATT), Sixth Rev. Vol. No. 1, Attachment V at 8.2 Execution of Generator Interconnection Study Agreement.

[97] Xcel Energy Operating Companies, FERC Electric Tariff (OATT), Third Rev. Vol. No. 1, Attachment N, Revised Large Generator Interconnection Procedures § 7.7 (Readiness Milestones and Site Control). These revised

inclusion rules used to determine ready projects. These include, for example, requirements for demonstration of site control and security deposits for various study phases. PJM Interconnection LLC has started a stakeholder process to discuss moving to as cluster-based interconnection study process using a first-ready/first-serve approach[98] which some regions, such as the NY ISO already employ. The Commission should encourage regions to consider similar criteria and should support approaches that prioritize certainty over flexibility in order to facilitate the interconnection process.

The Commission also seeks comment on whether it should require that transmission providers consider GETs in interconnection studies to assess whether their deployment can more cost-effectively facilitate interconnections.[99] EEI members have made significant investments in GETs that have demonstrated improvements in efficiency, capacity, reliability, and resiliency. These investments have also been cost-effective for customers. Going forward, GETs may play an important role in increasing efficient use of the system and providing a short-term solution until needed transmission is built. However, additional experience is needed to determine how best to model and operate these technologies. In addition, some of the GETs specifically referenced by the Commission in the ANOPR – power flow control and transmission switching equipment, storage technologies, and advanced line rating management technologies[100] – currently provide operational flexibility to system operators in the short-term. Since most GETs currently serve an operational rather than planning purpose, it is not appropriate to require that

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interconnection procedures were filed in Docket No. ER19-2774 and were accepted in *Pub. Serv. Co. of Colo.*, 169 FERC ¶ 61,182 (2019).

[98] Jason Connell, PJM Solution Proposal Framework Changes, PJM (2021), https://www.pjm.com/-/media/committees-groups/task-forces/iprtf/2021/20210920/20210920-item-02a-iprtf-solution-proposal-framework.ashx.

[99] *See* ANOPR at P 158.

[100] *Id.* at n.68.

these GETs be incorporated into the long-term planning processes contemplated by the Commission in the ANOPR.

In addition, due to uncertainties regarding long-term effectiveness, rapidly evolving technology rendering formerly installed technology obsolete, and concerns regarding cost recovery for these new investments, there are significant risks involved with the deployment of new technologies. Utilities may be unlikely to assume those risks unless a particular technology has already demonstrated substantial and immediate benefits to customers. But those benefits can be difficult to demonstrate until utilities have gained sufficient experience with the technology through pilot programs or more limited deployments. Thus, given the evolving nature of these technologies, there should be flexibility but not a requirement to evaluate them in the interconnection process. If the Commission wishes to encourage the use of GETs, then the Incentives NOPR may be the more appropriate vehicle for such discussion.

D. Oversight

The ANOPR put forth a number of questions related to the need for enhanced oversight, the need for a new transmission monitor and whether states should be more involved in oversight of the transmission planning process. The ANOPR does not identify the specific issues or the problem that the Commission is trying to address. As discussed below, there is substantial oversight in the current process and additional regulatory processes in this area are not needed.

1. The Current Transmission Planning Process Provides Transparency

The current transmission planning process provides sufficient transparency and enhanced oversight is not needed.[101] As discussed herein, Order Nos 890 and 1000 required changes to the transmission planning process to provide transparency and stakeholder participation. Order No.

[101] *See id.* at P 162.

890 required all transmission providers to amend their OATT to include an Attachment K that met the planning and stakeholder participation principles outlined in the Final Rule.[102] Transmission providers were also directed, in consultation with their stakeholders, during development of their Attachment K to develop a means to allow the transmission provider and stakeholders to cluster or batch requests for economic planning studies so that the transmission provider may perform the studies in the most efficient manner. The order also required that requests for economic planning studies, as well as the responses to the requests, be posted on the transmission provider's OASIS or web site, subject to confidentiality requirements.[103] All transmission providers have their Commission approved and enforceable Attachment K posted.[104]

In addition to the Order No. 890 requirements, transmission providers were required to make filings to comply with Order No. 1000 transmission planning and cost allocation requirements which built on the Order No. 890 planning principles. These Commission approved and enforceable compliance filings provide mechanisms for stakeholders to receive information and participate in the transmission planning process for regional and local projects.[105] All of the regions submitted compliance filings detailing how they would meet the

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[102] Order No. 890 at P 437.

[103] *Id.* at P 546.

[104] *See e.g.,* Florida Power & Light Company, FERC Electric Tariff (OATT), Attachment K (Effective Jan. 1, 2021), https://www.oasis.oati.com/woa/docs/FPL/FPLdocs/FPL_OATT_010121.pdf; Portland General Electric Company, FERC Electric Tariff (OATT), Attachment K (Effective Aug. 14, 2020), https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_OATT_08142020.pdf; Southern Company, FERC Electric Tariff (OATT), Attachment K (Effective Jan. 1., 2021),http://www.oasis.oati.com/woa/docs/SOCO/SOCOdocs/Southern-OATT_2021-01-01_revised_Attachments_C_&_V_relating_to_FPL-Gulf_Merger.pdf; Nevada Energy, FERC Electric Tariff (OATT), Attachment K, http://www.oatioasis.com/NEVP; and ISO NE, FERC Electric Tariff (OATT), Attachment K, https://www.iso-ne.com/static-assets/documents/support/training/courses/trans_plan/04_attachment_k.pdf.

[105] *See e.g.,* Order No. 1000 at PP 78-82, 148-58.

transparency provisions in Order No. 1000 and operate under tariffs approved by the Commission.[106]

2. An Independent Transmission Monitor Is Not Needed

There is sufficient oversight and transparency in the transmission planning and cost allocation process and another layer of review through an independent transmission monitor is

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[106] **CAISO:** *California Indep. Operator Corp.*, 143 FERC ¶ 61,057 (2013) (First Compliance Order); *California Indep. Operator Corp.*, 146 FERC ¶ 61,198 (2014) (Second Compliance Order); *California Indep. Operator Corp.*, 149 FERC ¶ 61,249 (2014) (Third Compliance Order); **Florida:** *Tampa Elec. Co.*, 143 FERC ¶ 61,254 (2013) (First Compliance Order); *Tampa Elec. Co.,*148 FERC ¶ 61,172 (2014) (Second Compliance Order); *Tampa Elec. Co.*, 151 FERC ¶ 61,013 (2015) (Third Compliance Order); *Tampa Elec. Co., Delegated Letter Order,* FERC Docket Nos. ER13-80-006, ER13-86-006, ER13-104-007, and NJ15-15-000 (Aug. 20, 2015); **ISO-NE:** *ISO New England Inc.,* 143 FERC ¶ 61,150 (2013) (First Compliance Order); *ISO New England Inc.,* 150 FERC ¶ 61,209 (2015) (Second Compliance Filing); *ISO New England Inc.*, 153 FERC ¶ 61,102 (2015) (Third Compliance Filing); *ISO New England Inc., Delegated Letter Order,* FERC Docket Nos. ER13-193-006 and ER13-196-005 (Dec. 14, 2015); **MISO:** *Midwest Indep. Transmission Sys. Operator, Inc.,* 142 FERC ¶ 61,215 (2013) (First Compliance Order); *Midwest Indep. Transmission Sys. Operator, Inc*., 147 FERC ¶ 61,127 (2014) (Second Compliance Order); *Midwest Indep. Transmission Sys. Operator, Inc.*, 150 FERC ¶ 61,037 (2015) (Third Compliance Order); *Midwest Indep. Transmission Sys. Operator, Inc., Delegated Letter Order,* FERC Docket No. ER13-187-010 (Mar. 31, 2015); **NYISO:** *N.Y. Indep. Sys. Operator, Inc.*, 143 FERC ¶ 61,059 (2013) (First Compliance Order); *N.Y. Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,044 (2015) (Second Compliance Order); *N.Y. Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,040 (2015) (Third Compliance Order); *N.Y. Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,341 (2015) (Fourth Compliance Order); *N.Y. Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,107 (2018) (Fifth Compliance Order); *N.Y. Indep. Sys. Operator, Inc.*, *Delegated Letter Order,* FERC Docket Nos. ER13-102-012 – -014 (June 5, 2018); **NorthernGrid:** *PacifiCorp.,* 169 ¶ FERC 61,249 (2019) (First Compliance Order); *PacifiCorp.,* 170 FERC ¶ 61,298 (2020) (Second Compliance Order) FERC Docket Nos. ER19-2763-000, ER20-882-000; **PJM:** *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013) (First Compliance Order); *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,128 (2014) (Second Compliance Order); *PJM Interconnection, L.L.C.*, 150 FERC ¶ 61,038 (2015) (Third Compliance Order); *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,250 (2015) (Fourth Compliance Order); **SERTP:** *Louisville Gas & Elec. Co.,* 144 FERC ¶ 61,054 (2013) (First Compliance Order); *Duke Energy Carolinas, LLC,* 147 FERC ¶ 61,241 (2014) (Second Compliance Order); *Duke Energy Carolinas, LLC*, 151 FERC ¶ 61,021 (2015) (Third Compliance Order); *Duke Energy Carolinas, LLC*, 152 FERC ¶ 61,078 (2015) (Fourth Compliance Order); *Ohio Valley Elec. Corp., Delegated Letter Order*, FERC Docket No. ER13-913-006 (Sept. 3, 2015); **South Carolina:** *South Carolina Elec. & Gas Co.*, 143 FERC ¶ 61,058 (2013) (First Compliance Order); *South Carolina Elec. & Gas Co.*, 147 FERC ¶ 61,126 (2014) (Second Compliance Order); *South Carolina Elec. & Gas Co.*, 150 FERC ¶ 61,036 (2015) (Third Compliance Order); *South Carolina Elec. & Gas Co.*, 151 FERC ¶ 61,197 (2015) (Fourth Compliance Order); *South Carolina Elec. & Gas Co., Delegated Letter Order,* FERC Docket No. ER13-107-009 (Aug. 3, 2015); **SPP:** *Sw. Power Pool, Inc.,* 144 FERC ¶ 61,059 (2013) (First Compliance Order); *Sw. Power Pool, Inc.,* 149 FERC ¶ 61,048 (2014) (Second Compliance Order); *Sw. Power Pool, Inc.,* 151 FERC ¶ 61,045 (2015) (Third Compliance Order); *Sw. Power Pool, Inc.,* 152 FERC ¶ 61,106 (2015) (Fourth Compliance Order); **WestConnect:** *Pub. Serv. Co. of Col.*, 142 FERC ¶ 61,206 (2013) (First Compliance Order); *Pub. Serv. Co. of Col.*, 148 FERC ¶ 61,213 (2014) (Second Compliance Order); *Pub. Serv. Co. of Col.*, 151 FERC ¶ 61,128 (2015) (Third Compliance Order); *Pub. Serv. Co. of Col.*, 153 FERC ¶ 61,073 (2015) (Fourth Compliance Order); *Xcel Energy Serv. Inc., Delegated Letter Order,* FERC Docket No. ER13-75-010 (Jan. 21, 2016) (Fifth Compliance Order); *Pub. Serv. Co. of Col.*, 161 FERC ¶ 61,188 (2017) (Sixth Compliance Order).

not needed.[107] First, as discussed above, Order No. 1000 mandated that regions implement a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation.[108] All of the regions have implemented the requirement and operated under tariffs approved by the Commission. There is no evidence that the existing processes, whether in or outside of a RTO/ISO region, are failing to implement tariffs appropriately or that the processes produce unjust and unreasonable outcomes under the enforceable Commission-approved processes. If there are concerns, stakeholders can work with their regions to develop additional processes.

Second, given that there have not been any findings that the current processes are unjust and unreasonable, the need for an independent transmission monitor to second guess the results or the process has not been demonstrated. Rather than facilitate the process, the addition of an independent transmission monitor will add another layer of review, which will cause delays and additional costs without any identifiable benefits. Projects are selected by the regions through the Commission approved process in conjunction with the stakeholders. Adding another entity to the process could lead to increased litigation and disputes if there is a disagreement as to which project should be selected resulting in additional delays and potentially significant costs which would then be passed on to customers.

Third, while it is appropriate to have independent market monitor for the capacity, energy, and ancillary services markets as we have today, transmission does not present the same issues. Unlike generators that the Commission determines to not have market power and able to sell services at market-based rates, transmission is a cost of service regulated service. Prior to

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[107] *See* ANOPR at P 165.

[108] Order No. 1000 at P 328; Order No. 1000-A at P 452.

making a change to their rates, TOs are required to make a section 205 filing with the Commission that is then subject to review by other stakeholders, including discovery. Plans to expand are public through the Order Nos. 890 and 1000 planning processes, the standards by which TOs plan are public, as are the models. This differs from the energy markets where the bids are confidential and plans for expansion are not known or subject to public process. In addition, all public utilities are also regulated at the state level and subject to oversight and scrutiny from their state commissions.

The Commission appears to be concerned with whether changes are needed to facilitate the consideration of more efficient or cost-effective technologies and placement of those technologies when generator retirement decisions are made.[109] Adding another layer of review through a market monitor will not address these issues.[110] The Commission approved tariffs already require public utility transmission providers "to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[111] If the Commission believes that additional exploration is needed as to why specific technologies are not being implemented, then the issue is best addressed through the path that the Commission has already embarked on which is seeking information through technical conferences[112] and seeking

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[109] *See* ANOPR at P 171.

[110] In RTOs/ISOs, Commission approved tariffs govern the process to be used when a generation retirement is announced. The independent market monitors are involved in this process. Outside of RTO/ISO regions, states play an important role in approving IRP and approving decisions made by the utilities, including retirement decisions.

[111] Order No. 1000 at P 148.

[112] *See e.g., Grid-Enhancing Technologies*, Supp. Notice of Workshop, 84 Fed. Reg. 59804 (Nov. 6, 2019); *Elec. Transmission Incentives Policy under Section 219 of the Fed. Power Act*, Second Supp. Notice of Workshop, 86 Fed. Reg. 51348 (Sept. 15, 2021).

comments on incentives that may help accelerate the process.[113] Adding another layer of administrative oversight to a process that, as discussed above, already has significant oversight and transparency will not address these issues and will impose associated costs that will serve to delay the process and possibly decrease transmission investment.

3. States Already Play an Important Role in the Transmission Planning Process

States already play an important role in the process and additional state oversight is not needed.[114] The current processes provide significant opportunity for input in all areas of the country as detailed in the tariff provisions implementing Order No.1000 requirements. There may also be additional opportunities for local projects or integrated resources plans outside of RTOs and ISOs. For example, in the NY ISO Public Policy Transmission Planning Process, the New York Public Service Commission ("NY PSC") declares a Policy Transmission Need ("PPTN"). Pursuant to this process, the NY ISO is responsible for selecting the efficient or cost-effective transmission solution from the competing projects to address a transmission need driven by the PPTN. Additionally, at a local level, the NY PSC is involved in approving local transmission projects by approving/rejecting transmission and distribution bundled rates. In Nevada, public utilities are required to submit integrated resource plans to the state commission for approval as prudent investment. The approval process includes hearings and opportunities for public comment and information requests.[115] Other states inside and outside of RTO/ISO regions have similar provisions.

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[113] Incentives NOPR at PP 100-12.

[114] *See* ANOPR at PP 175-76.

[115] Nev. Rev. Stat. Ann. §§ 58-703.010, *et seq.* and 58-704.010, *et. seq*. (2020); and Nev. Admin. Code, Chapters 703-04 (2021).

E. Transition

Any changes that the Commission makes to the transmission planning process as contemplated in the ANOPR should be prospective so as not to create uncertainty for transmission and generation projects that are currently in the planning and interconnection processes. In addition, a number of regions are discussing proposed changes to their transmission planning and interconnection processes that impact a number of issues raised in the ANOPR. The Commission should take these ongoing discussions into consideration in developing its proposals so that the stakeholder discussions and proposed changes can go forward with a sense of regulatory certainty.

V. CONCLUSION

As discussed herein, Commission policies have generally worked well in facilitating transparency and input into the transmission planning process and targeted changes will help address Commission concerns about getting needed transmission built. EEI appreciates the opportunity to submit comments on the ANOPR and looks forward to continuing to engage in discussions on these important issues going forward.

Respectfully submitted,

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