UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF AMERICAN ELECTRIC POWER COMPANY, INC.

American Electric Power Company, Inc. ("AEP") respectfully provides comments in response to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Notice of Inquiry Regarding the Commission's Electric Transmission Incentives Policy.[1]

I. EXECUTIVE SUMMARY

In undertaking this timely effort to review and update the Commission's transmission incentives policies, the Commission should focus on ensuring that incentive policy is deployed to support the policy goals of the Commission and enhance benefits to customers. Many aspects of the Commission's current incentive policies continue to meet those goals. Moreover, new policy concerns support new uses of incentive policy. AEP offers the following specific comments:

- <u>The Commission should continue to provide a return on equity ("ROE") adder for RTO[2] participation</u>. RTOs continue to provide benefits to consumers that far, far exceed the cost of this incentive. FERC has actively encouraged the formation and expansion of RTOs, recognizing the widespread consumer benefits of expanding wholesale market competition, planning transmission regionally, and efficiently providing for grid reliability. Moreover, RTOs provide a strong and valuable regional foundation for addressing today's grid resilience challenges. As RTO participation is not required by federal law, and transmission owners continue to consider joining, and departing from, RTOs, an incentive for participation remains important. Additionally, the 2005 Federal Power Act ("FPA") amendments specifically require FERC to provide incentives for each transmission owner that joins an RTO.

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[1] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Notice of Inquiry, 166 FERC ¶ 61,208 (2019), 84 Fed. Reg. 11,759 (Mar. 28, 2019) ("Incentives NOI").

[2] For simplicity, regional transmission organizations and independent system operators are referred to collectively herein as "RTOs."

  - Given the large benefits of RTOs in comparison to the costs of the participation incentive, and the ability of RTOs to help enhance grid resilience and security, an increase in the size of the ROE-adder for RTO participation ("RTO Participation Adder") would be justified. RTOs provide very substantial benefits to customers. These public benefits far exceed the current 50 basis point incentive. Furthermore, the requirements placed upon transmission owners that are in RTOs have increased substantially since the RTO Participation Adder was first introduced.

- FERC should offer a Grid Resilience Incentive. As reflected by the recent FERC and Department of Energy ("DOE") technical conference on security investments, FERC has a strong interest in promoting robust system hardening for reliability and resilience. Transmission rate incentives are an important tool to advance these policy imperatives. AEP proposes an approach whereby a transmission owner could submit to FERC a company-specific Resilience and Security Action Plan, in conjunction with a request for incentive rate treatment. FERC would assess the resilience benefits of the plan, and determine an appropriate incentive, informed by how the plan supports the Commission's resilience policies. RTOs can also be utilized to address additional resilience needs and assessments across their footprint and support evaluation and implementation of these action plans.

- Certain risk-mitigating, non-ROE incentives should be provided through a streamlined process:

  - The Abandonment Incentive[3] should be granted automatically to developers of new transmission projects undertaken pursuant to a regional transmission expansion plan. Where the planning region has initiated the project, rather than the developer, there is no policy rationale for requiring the developer to bear a share of prudently incurred project costs if the project is abandoned for reasons outside the developer's control.

  - New entrant transmission developers should be granted Regulatory Asset and Hypothetical Capital Structure incentives upon request. Recognizing that these incentives help level the playing field between new entrants seeking to compete for transmission development opportunities and incumbent utilities, FERC has routinely granted these incentives under section 205. FERC should codify this practice and simplify the required application, as this approach supports competition.

- Transmission owners should be permitted to request capital treatment for targeted expenditures. To incent high-value activity in areas that would enhance transmission

[3] The Abandonment Incentive refers to authorization for a transmission developer to recover 100% of prudently incurred abandoned plant costs where a project has been cancelled for reasons outside of the developer's control, subject to a post-abandonment filing under section 205.

efficiency and reliability, such as state-of-the-art vegetation management programs, the Commission should consider an incentive to allow for the recovery of specified operations and maintenance ("O&M") expenses as capital costs for ratemaking purposes.

II. DESCRIPTION OF AEP

AEP is one of the largest electric utilities in the United States, delivering electricity to nearly 5.4 million customers in 11 states.[4] AEP ranks among the Nation's largest generators of electricity, owning nearly 26,000 megawatts of generating capacity in the United States. AEP also owns the Nation's largest electric transmission system, with more than 40,000 miles of transmission lines and more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10% of the electricity demand in the Eastern Interconnection. AEP has a broad and unique perspective on RTO operations and benefits in that it is a member of four RTOs – PJM Interconnection, L.L.C. ("PJM"), Southwest Power Pool ("SPP"), Midcontinent Independent System Operator, Inc.'s ("MISO"), and the Electric Reliability Council of Texas ("ERCOT").

AEP is also the majority owner of Transource Energy, a joint venture between AEP and Great Plains Energy Incorporated, a holding company for competitive transmission development-focused subsidiaries throughout the United States. Transource Energy is in the business of developing cost-effective transmission solutions in response to competitive solicitations. AEP also participates in a number of joint ventures to own transmission projects throughout the Nation.[5]

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4 AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana, and east Texas).

5 These transmission joint ventures include: Electric Transmission Texas (a joint venture of AEP and MidAmerican Energy Holdings Company to build transmission projects within ERCOT); Pioneer Transmission LLC (a joint venture of AEP and Duke Energy); Prairie Wind Transmission LLC (a joint venture of Westar Energy and Electric Transmission America, which is itself a joint venture of subsidiaries of AEP and MidAmerican Energy

Given the scope of its geographic coverage, the magnitude and diversity of assets in its portfolio, and its experience in the various regional market structures, AEP has a broad perspective on the use and effectiveness of the Commission's transmission incentive policies.

III. COMMENTS

AEP commends the Commission for undertaking a review of its transmission incentive policies, and provides recommendations based on its experience with the existing policies and its views on the future for transmission development. The transmission grid is the backbone of the Bulk Electric System. Continued investment in transmission is critical to ensure that the grid continues to meet the changing needs of customers, to adapt in support of electrification of industry and transportation, to meet the needs of an evolving generation mix, and to recognize and to reduce congestion in an efficient manner. Without a robust transmission system, electricity markets and the cost savings they produce simply could not exist. As Congress recognized in the Energy Policy Act of 2005,[6] incentives for transmission investment are an important component in ensuring the transmission grid meets the Nation's future needs.

AEP supports the thrust of the comments being filed by the Edison Electric Institute, WIRES, and the PJM Transmission Owners in this proceeding. AEP submits these company-specific comments to highlight the considerations below.

A. The Commission's Incentive Policies Should Focus on Benefits as Well as Risks.

In the Incentives NOI, the Commission first poses several questions on whether the "risks and challenges" evaluation remains an effective framework for its review of applications for

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Holdings Company, to build and own electric transmission in Kansas); and RITELine Transmission (a joint venture of Exelon Corporation and AEP to build and operate transmission in Indiana and Illinois).

[6] Pub. L. No. 109-58, 119 Stat. 594 (2005).

incentives.[7] AEP suggests that consideration of whether an incentive advances FERC policy goals and/or leads to customer benefits are at least as important as factors that focus on risks and challenges.

For ROE adder incentives, a benefits-driven evaluation of proposed project or programs, as opposed to a risk-based evaluation, would best serve the public interest. Through incentives for certain specified actions, the Commission has the opportunity to steer the deployment of the finite resources available to transmission owners and developers to enhance benefits for customers and best serve the Commission's long-term policy goals. Incentives policy can be a tool for creating greater alignment between public interests and shareholder incentives.

B. The Commission Should Continue to Provide the RTO Participation Adder.

The Commission seeks comment on the existing incentives granted under Order No. 679. Among these is the RTO Participation Adder. FERC should continue to provide an RTO Participation Adder because:

RTOs provide substantial benefits to customers and recognize utilities' contribution

- RTO participation provides very significant benefits to ratepayers, and advances long-standing FERC policy goals (such as regional transmission planning, reserve sharing, and regional electric market development);

- Utilities must give up substantial control over their own transmission systems when joining an RTO. The loss of flexibility, autonomy and control over transmission-related decisions creates a significant barrier to entities joining, and remaining members of, RTOs;

The RTO Participation Adder directly influences RTO membership

- RTO membership is not static, and transmission owners can join and depart from RTOs over time;

- The RTO Participation Adder encourages entities to remain members of an RTO;

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[7] Incentives NOI at P 15.

- A large number of transmission owners have not yet joined RTOs despite the current incentive;

RTOs are well positioned to provide even more benefits in the future

- RTOs can provide even more benefits in the future by further supporting grid resilience and security. These benefits further support a robust RTO Participation Adder; and

The RTO Participation Adder addresses the requirements of current law

- The FPA specifically directs FERC to establish an incentive for transmission owners that join an RTO.

1. Legal Requirement for an RTO Participation Adder

The establishment of an RTO participation incentive by FERC was expressly required in the Energy Policy Act of 2005. In that law, Congress added section 219 to the FPA, which directed FERC to establish, by rule, incentive-based transmission rate treatments to ensure reliability and reduce transmission congestion. The key statutory goal was to provide ample return on equity to attract investment in transmission facilities.[8] Section 219(c) specifically directs that FERC establish incentives for RTO participation:

> In the rule issued under this section, the Commission *shall*, to the extent within its jurisdiction, *provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization*. The Commission shall ensure that any costs recoverable pursuant to this subsection may be recovered by such utility through the transmission rates charged by such utility or through the transmission rates charged by the Transmission Organization that provides transmission service to such utility.[9]

The Commission addressed the mandate of section 219(c) in Order No. 679,[10] explaining that it "will approve, when justified, requests for ROE-based incentives for public utilities that

8 16 U.S.C. § 824s.

9 *Id*. § 824s(c) (emphasis added).

10 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) ("Order No. 679"), *order on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

join *and/or continue to be a member of* an ISO, RTO, or other Commission-approved Transmission Organization."[11] The Commission established a presumption that an entity is "eligible for the incentive if it can demonstrate that it has joined an RTO, ISO, or other Commission-approved Transmission Organization, and that its membership is *ongoing*."[12] The Commission 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. The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact continuing membership is generally voluntary.[13]

The Commission recently has faced a challenge to the continued application of an RTO Participation Adder where state law includes provisions addressing transmission owner RTO participation.[14] However, the FPA requires that FERC maintain an RTO participation incentive for each transmission owner joining an RTO; this obligation is not dependent on whether there may be state laws that address RTO participation.[15] Moreover, as discussed above, the customer benefits of RTO participation are much bigger than the cost of the RTO Participation Adder, and these benefits accrue whether or not there is a state law requirement mandating participation.

2. RTO Membership Provides Great Value for Customers.

There are many customer benefits gained from RTOs. The operation of the transmission grid regionally supports competitive power markets covering large geographic areas and

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[11] Order No. 679 at P 326 (emphasis added).

[12] *Id.* at P 327 (emphasis added).

[13] *Id.* at P 331. The Commission did not further address the RTO membership incentive in its 2012 policy statement on transmission incentives. *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 at P 5 (2012).

[14] *See Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966, 974-75 (9th Cir. 2018) ("CPUC Opinion").

[15] At issue on remand of the CPUC Opinion is whether continued participation in an RTO is required under the relevant California law. *See Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,121 at P 25 (2018).

facilitates the development of organized spot markets for energy and capacity, both of which support the Commission's goal of creating large, open, and competitive wholesale power markets. As noted above, without robust transmission, there would be no regional market. Transmission access and regional power delivery depend on a well-planned transmission system and continued transmission investment to meet evolving needs.

Further, there are many transmission-related benefits of RTO participation, including:

- Planning coordination to meet regional transmission reliability needs;
- Increased resilience through regional planning for disaster recovery and access to real-time data for analysis of risks to the grid;
- Regional perspective on project planning to develop the most efficient, cost-effective grid solutions to reliability, economic and state and federal public policy needs;
- Facilitation of stakeholder forums to provide a more transparent planning process;
- Operational oversight for Transmission Operations functions and outage coordination;
- Facilitation of Order No. 890 and Order No. 1000 compliance;
- Efficient coordination of generation interconnection queue; and
- Standardization of design and planning standards among Transmission Owners.

Importantly, RTOs have the authority and oversight to positively impact grid resilience. RTOs promote collaboration and coordination through their regional planning processes and provide a useful forum for identifying changes needed to reduce the number of facilities deemed as "critical." RTOs facilitate planning for black start on a region-wide basis. RTOs can also use real-time data from new technologies, such as synchrophasors, in their analytical tools to evaluate risks to the operation of the grid. The RTOs are in a unique position to perform these functions over a much larger area than are individual transmission owners.

Furthermore, RTO membership provides additional value and cost savings to customers. A robust transmission system under the operational control of an RTO allows for efficient generation dispatch over a larger fleet of resources. This generation cost savings provides benefits to consumers. The mix of generation resources is changing rapidly as is the ideal location for new resources. Regionally-planned transmission enables the development of all forms and sizes of new generation. Planning on a regional level ensures that the new generation has the ability to reach consumers across the RTO's footprint. Regional planning also has assisted in the reduction of emissions by enabling the entry of more renewable generation as well as new technologies like demand response.

A diverse generation mix, as supported by robust regional transmission, lowers outage risks and allows RTOs to better optimize dispatch and reserve margins. This increases reliability and decreases costs for consumers. The fast-paced changes occurring in the industry combined with more frequent and intense weather events has also led RTOs to consider and build resilience concepts into their planning processes. This benefits the consumer by allowing RTOs, generator owners and transmission owners to better withstand such events and recover faster if a significant disruption occurs.

RTOs provide billions of dollars in benefits to customers each year. For example, PJM recently studied the benefits created by the RTO in its region, by estimating the value of several factors that enhance the reliability of the region, such as load diversity, generation fleet diversity, and transmission ties between zones. Overall, PJM estimated that the RTO reduces the need for additional capacity by an estimated $3.78 billion annually, benefits that would not occur in the absence of the RTO.[16] With respect to power costs, PJM explained that its grid operations schedule and direct the lowest-cost power resources to generate electricity first, incrementally

[16] PJM Interconnection, L.L.C., The Benefits of the PJM Transmission System at 21 (Apr. 16, 2019), *available at* https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en.

adding more expensive resources as needed and saving the highest-cost resources for relatively brief periods of peak customer demand. PJM estimated the benefits of access to lower priced power, using costs reductions expected to be gained by transmission enhancements in PJM, will reduce costs to customers by more than $288 million a year by alleviating congestion. PJM also estimated enhanced market savings of $1.7 billion through its 2020/2021 capacity auction. Finally, while not attempting to provide a corresponding dollar value, PJM noted additional benefits gained by the region that support public interest goals such as economic growth, operational flexibility, resolving aging infrastructure issues, access to support in emergency conditions, resilience, and ensuring reliability during historic generation shift. These benefits to consumers exceed the cost of the RTO Participation Adder by more than an order of magnitude.

Similarly, according to the MISO 2018 Value Proposition study,[17] MISO provided an estimated $3.2 billion to $3.9 billion in net annual benefits to its region. MISO bases its analysis on several factors that it identifies as driving positive value for the region: improved reliability, efficient energy dispatch, unified regulation market, shared spinning reserves, wind integration, compliance, footprint diversity, improved generator availability and demand response. From 2007 through 2018, MISO estimates that it delivered $24.3 billion in cumulative net benefits to the region.

3. A Substantial Number of Transmission Owners Have Not Yet Joined RTOs, but Utilities Continue to Consider RTO Participation.

To date, RTOs have not been formed in the Southeast, Mountain West, Northwest, or Southwest regions. As a result, a substantial number of transmission owners are not in RTOs. As such, the substantial benefits of being in an RTO are not extended to all customers.

[17] Midcontinent Independent System Operator, 2018 Value Proposition, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ (last visited June 25, 2019).

Further, there is no federal law requirement to participate in an RTO.[18] Utilities continue to join and depart from RTOs. As evidenced by recent entrants and departures from these markets, RTO membership is not static. For example, after nearly two years of consideration of the benefits and costs of membership and lengthy state commission hearings, the electric utility companies held by Entergy Corporation ("Entergy") joined MISO in December 2013.[19] In the same time frame, several smaller utilities, including Cleco Power LLC,[20] South Mississippi Electric Power Association, Louisiana Energy and Power Authority, Louisiana Generating LLC, and four municipal utility systems joined MISO in the newly formed MISO South region.[21] As seen in the study performed to evaluate Entergy's entrance into the MISO markets, the RTO participation cost and value figured prominently in the analysis.[22] In addition, Valley Electric Association, Inc. and the City of Colton, California joined the California Independent System

[18] *See Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cty., Wash. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001)). In fact, FERC attempted, but eventually declined, to require formation of RTOs or the equivalent throughout the country. *See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, FERC Stats. & Regs. ¶ 32,563 (2002), *terminated by*, 112 FERC ¶ 61,073 (2005).

[19] Entergy announced its proposal to join MISO in 2011. The FERC order conditionally approving the tariff revisions to accomplish this integration was issued in April 2012. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,056, *reh'g denied*, 141 FERC ¶ 61,128 (2012), *order on reh'g & compliance*, 144 FERC ¶ 61,020 (2013).

[20] *Midcontinent Indep. Transmission Sys. Operator, Inc.*, 145 FERC ¶ 61,208 (2013).

[21] *See Midcontinent Indep. Transmission Sys. Operator, Inc.*, 145 FERC ¶ 61,244 (2013) (approving tariff revisions to complete the integrations in the MISO South zone), *reh'g denied*, 148 FERC ¶ 61,094 (2014).

[22] In May 2011, Entergy's utility operating companies submitted a report to their five retail regulators outlining the analysis and support for the decision to join MISO. The Report, "An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies and Support for Proposal to Join MISO," dated May 12, 2011, is available in the state public service commission dockets. *See, e.g.*, *Ex Parte: Application of Entergy Louisiana, Inc. and Entergy Gulf States, Inc. for Review of Proposal to Establish Independent Coordinator of Transmission*, An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies and Support for Proposal to Join MISO, Docket No. U-28155 (La. Pub. Serv. Comm'n filed May 12, 2011), *available at* http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=bc5c1788-4ce0-4daa-9ad0-71f09ad43643.

Operator Corporation as participating transmission-owning members in 2012.[23] Western Area Power Authority – Upper Great Plains Region, Basin Electric Power Cooperative, and Heartland Consumers Power District,[24] as well as a portion of Missouri River Energy Services,[25] joined SPP in 2015.

On the other hand, some utilities have chosen to leave RTOs, such as Louisville Gas & Electric Co. and Kentucky Utilities Co. in 2006.[26] Others have decided not to join or to defer the decision to join RTOs. For example, entities in the Mountain West Transmission Group ("MWTG") considered the costs and benefits of forming an RTO or joining SPP.[27] Public Service Company of Colorado and Black Hills Energy have decided not to join an RTO.[28] The Western Area Power Administration, also a member of MWTG, has decided to defer further consideration of RTO membership.[29]

4. The Tremendous Benefits RTOs Provide Would Justify an Increase in the Size of the RTO Participation Adder.

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23 *See California Independent System Operator Corp.*, Letter Order, Docket No. ER13-71-000 (issued Nov. 6, 2012) (letter order accepting Amended and Reinstated Transmission Control Agreement).

24 *Sw. Power Pool, Inc.*, 149 FERC ¶ 61,113 (2014), *clarified by*, 153 FERC ¶ 61,051 (2015), *pet. for review denied, State Corp. Comm'n of Kan. v. FERC*, 876 F.3d 332 (D.C. Cir. 2017).

25 *See Sw. Power Pool, Inc.*, 152 FERC ¶ 61,247 (2015).

26 *Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282 (2006), *clarified by*, E.ON U.S. LLC, 116 FERC ¶ 61,020 (2006). The Commission rejected intervenor arguments against this departure citing the voluntary nature of RTO membership. *Id*. at P 29.

27 Membership of the MWTG includes Basin Electric Power Cooperative, Black Hills Energy, Colorado Springs Utilities, Platte River Power Authority, Tri-State Generation and Transmission Association, and Western Area Power Administration. Public Service Company of Colorado withdrew its membership in the MWTG in April 2018.

28 News Release, "Xcel Energy to End Participating in MWTG, RTO Effort" (Apr. 20, 2018). Letter from Daniel Kline, Black Hills Energy, to Drew Bolin, Public Utilities Commission of Colorado, Docket 16I-0816E (Colo. Pub. Utils. Comm'n filed. Oct. 3, 2018).

29 Western Area Power Administration, WAPA Notice to Customers and Interested Parties (Oct. 30. 2018), *available at* https://www.wapa.gov/About/the-source/Documents/2018-defer-mountain-west.pdf.

Given that transmission owner participation in RTOs creates public benefits of great significance and scale, and that the economic benefits of RTO participation far outweigh the costs of the RTO Participation Adder, an increase in the size of the RTO Participation Adder would be justified. As shown above, RTOs create billions of dollars of net cost savings and other value to customers each year. Much of this RTO value is from the broad, competitive power markets supported by the RTO's regionally planned and independently operated transmission grid. It is appropriate to provide reasonable sharing of the tremendous benefits produced by the RTO participants' cooperative approach between customers and the investors that have contributed their transmission assets to this cooperative enterprise in the public interest. The current and future public and consumer benefits of RTOs and RTO membership by transmission owners justify increasing the RTO Participation Adder. Furthermore, the requirements placed upon transmission owners that participate in RTOs have dramatically increased since the time the RTO Participation Adder was originally established. These increasing obligations resulting from participation of transmission owners in RTOs would also support an RTO Participation Adder greater than 50 basis points.

C. The Commission Should Adopt a New Resilience Incentive Framework

As discussed in AEP's post-technical conference comments in Docket No. AD19-12,[30] AEP encourages the Commission to offer an incentive to advance its policy objectives on grid resilience.[31] One of the issues highlighted at the technical conference held on March 28, 2019, and heard throughout the industry, is the potential gap between the dynamic threats faced by the

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[30] FERC and DOE held a joint technical conference to address "Security Investments for Energy Infrastructure" on March 28, 2019. *See* Transcript from March 28, 2019 Technical Conference, Docket No. AD19-12-000 (issued Apr. 26, 2019).

[31] Post-Technical Conference Comments of American Electric Power Company, Docket No. AD19-12-000 (filed May 28, 2019).

energy industry and the reliability standards development and compliance process which sets the rules for minimum compliance. A supplemental policy that supports resilience using incentives to drive proactive utility efforts on cyber and physical security and to encourage transmission owners to go beyond minimum compliance with the reliability standards could create a more proactive approach to enhancing grid resilience. Given that each transmission owner may face different threats and circumstances, the approach to grid resilience incentives should be customizable and flexible.

AEP recommends that the Commission establish an incentive to permit enhanced return on equity on the transmission rate-base for utilities with approved programs to improve resilience and security of the transmission owner's system. The program would be developed and approved under a multi-step approach.

- Transmission owner develops company-specific Resilience and Security Action Plan. A transmission owner would review its system and develop a utility-specific Resilience and Security Action Plan ("Action Plan"). The Action Plan may include capital projects, ongoing operation and maintenance activities and participation in collaborative programs, and would provide a detailed rationale as to how the transmission owner's enumerated actions would improve its system's security or resilience. Like an integrated resource plan, the Action Plan would, among other things, include timetables and budgets, as well as an assessment on what types of threats are addressed and how the planned actions would enhance grid resilience, in order to assist the Commission with its analysis of the Action Plan.

- FERC assesses Action Plan. The Commission would perform an assessment of the proposed Action Plan, and could consider using an independent assessment tool, such as the resilience maturity model developed by the DOE, Electric Power Research Institute ("EPRI") and the North American Transmission Forum ("NATF") or other similar applications.[32] The RTOs, the North American Electric Reliability Corporation

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[32] DOE and NATF continue work on such models. DOE, Asst. Sec. B. Walker, "Keeping the Nation's Critical Energy Infrastructure Secure and Resilient Requires a Strong STEM Workforce" (Apr. 5, 2019), *available at* https://www.energy.gov/articles/keeping-nation-s-critical-energy-infrastructure-secure-and-resilient-requires-strong-stem ("One of our priorities is to develop an integrated North American Energy Resilience Model (NAERM) to conduct planning and contingency analysis to address vulnerabilities in the North American energy system"); 2018 Southeastern Association of Regulatory Utility Commissioners (SEARUC) Conference, Talking Points for Asst. Sect. Bruce Walker, DOE, at 6-7 (June 11, 2018), *available at* https://www.energy.gov/sites/prod/files/2018/07/f53/Walker%2006-11-18%20SEARUC%20Remarks%20-

("NERC"), or the regional reliability may also have a helpful perspective in assessing the benefits of a transmission owner's proposed Action Plan. As noted above, each RTO has extensive experience and expertise concerning its region and could provide guidance on elements covered by transmission owner Action Plans. We envision that utilities that are not in an RTO would provide an assessment of the resilience needs and benefits of the utility's Action Plan from an independent third party with expertise in assessing resilience.

- FERC determines incentive supported by Action Plan. After evaluating the transmission owner's Action Plan, the Commission would consider whether the Action Plan supports the applicant's requested transmission rate incentive, informed by how the plan supports the Commission's resilience policies. This would enable the Commission decide on a case-by-case basis whether the transmission owner's request is warranted based on the record before it. Incentives would take the form of an appropriate system-wide ROE adder, with the size of the adder scaled to the ambition of the Action Plan and resulting system-wide resilience benefits. Use of a system-wide ROE incentive is appropriate because a comprehensive resilience Action Plan would help protect all of the system's facilities against a wide array of threats.

By allowing each transmission owner the flexibility to create an Action Plan that is best suited to advancing grid resilience in its circumstances, this approach is customizable and efficient. This recognizes that each transmission owner has a system with its own unique characteristics, each transmission owner starts at a different level of resilience and security maturity, and each transmission owner may face different cost-benefit economics.

Under this resilience incentive policy, a transmission owner may include a number of resilience and security actions in its Resilience and Security Action Plan, such as:

1. *Planning the system in a manner that reduces the number of substations designated as NERC critical transmission substations* – After Pacific Gas & Electric Company's Metcalf Substation was attacked in 2013, NERC implemented a Critical Infrastructure Protection ("CIP") Reliability Standard addressing the identification and protection of

%20As%20Prepared.pdf ("My office's first priority is the creation of a North American Energy System Resiliency Model. This model capitalizes on previous National Lab work and is being leveraged to fully understand the resiliency risks associated with operating a highly diversified regionally isolated grid that supplies electric energy for North America. Also, the model will include analysis regarding the significant interdependencies that have evolved over the last couple decades between the various energy infrastructures."); Speaker materials of Tom Galloway, North American Transmission Forum, 2018 Reliability Technical Conference, Docket No. AD18-11-000 (issued Aug. 2, 2018).

transmission substations and their associated primary control centers.[33] As a part of a holistic Action Plan, a transmission owner could commit to execute projects to eliminate the critical designation for existing substations. Going forward, the utility could plan in a manner so that substations are not added to the critical infrastructure designated list.

2. *Participating in a sparing equipment service to improve grid recovery capability* – This action entails subscribing to a sparing service that owns and controls an inventory of critical spare transmission equipment, in order to have immediate access and planned deployment of new, secure and dedicated replacement equipment in the event of a grid catastrophe. AEP, for example, intends to subscribe to Grid Assurance, which will improve grid resilience by drastically cutting the long lead time for obtaining critical transmission equipment like spare transformers and circuit breakers following catastrophic events that damage critical transmission equipment.[34] Sharing the cost of this type of shared spare equipment inventory with other subscribers provides a cost savings to customers relative to utility-by-utility sparing strategies.

3. *Deploying a private communications network* – A transmission owner could improve security by deploying a secure private communications network. For example, while AEP owns some of the fiber optic cable it utilizes, it also relies on third-party telecommunication service providers. This could lead to operational and security issues. Deploying a utility-owned private network is more secure and allows greater control of the system. It mitigates cyber security risks by reducing corporate attack surfaces and cyber vulnerabilities as well as mitigating physical security risks by enhancing the surveillance of transmission substations. Secure private communication networks are a vital component of a modernized grid because it brings greater bandwidth to substations and enables differential protection for better performance with regard to protection and control. It also allows for finer flexibility for remotely shedding load, if required.

4. *Heightening reliability of electric service to natural gas pipelines* – A utility's Action Plan could include projects to heighten the reliability of electric service used to support natural gas pipeline infrastructure. As the Commission is well aware, for the foreseeable future, natural gas is forecasted to remain the primary fuel for U.S. electricity generation. Growing demand and finite pipeline capacity make the reliability of interstate gas pipelines critical, especially during cold weather events. An electric utility could put projects in place to increase the reliability of electric service to compressor stations that use electric motors to move natural gas through the pipeline as well as to natural gas processing facilities.

5. *Other possible elements* – There are many other types of investments, programs, and initiatives that could be included in an Action Plan. Actions suggested by the discussion at the March 28th technical conference on infrastructure security included: taking early actions that anticipate future standards still in the development process; aggressive action

[33] NERC Reliability Standard CIP-014-2 (Physical Security) requires a risk assessment to identify such facilities and the development of a documented physical security plan for these facilities.

[34] Information about Grid Assurance can be found at: https://www.gridassurance.com/.

> on enhancing supply chain security; programs to expand the cybersecurity workforce; and programs to enhance workable collaboration with states. Additional Action Plan elements could also include: projects along the switching path to ensure that once particular black start generators come on line, they are able to connect to the next generator so that the grid can recover more quickly; making incremental investments in SCADA equipment in conjunction with the utilization of real-time assessment tools; using resilient designs and materials, such as EMP hardened control houses, coated insulators, or composite core insulators; enhanced cyber security measures, such as broad adoption of regular penetration testing to simulate attacks on computer systems to discover potential points of exploitation; substation physical security measures at substations beyond those designated as critical; and other measures to bolster resilience.

The Commission guidelines for resilience and security Action Plans should be flexible. The examples provided above are only some of the ideas of components a utility seeking a grid security and resilience incentive could build into its Action Plan. The Action Plan would include, among other things, an assessment on what types of threats are addressed by the elements of the Action Plan, and how the planned actions would enhance grid resilience in the face of those threats.

There are available tools for the Commission to use in evaluating proposed Action Plans. As discussed on the second panel at the March 28th technical conference, there exist several independent assessment models, such as the DOE/EPRI/NATF-developed Electricity Subsector Cybersecurity Capability Maturity Model ("ES-C2M2"),[35] that could be employed. The RTOs, NERC, or the regional reliability organizations may also be helpful in assessing the benefits of a transmission owner's Action Plan.

This new resilience incentive would be squarely in line with the Commission's goals for improving reliability and resilience of the transmission grid. This incentive would also benefit consumers by mitigating outage risks and shortening restoration and recovery times after any event.

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[35] For further information on ES-C2M2, see https://www.energy.gov/ceser/activities/cybersecurity-critical-energy-infrastructure/energy-sector-cybersecurity-0-1.

D. The Commission Should Automatically Grant the Abandoned Plant Incentive for Projects in an RTO-Approved Plan.

Certain non-ROE incentives are important and appropriate ratemaking tools that help transmission developers to manage the risks and challenges of project development.[36] In the Incentives NOI, the Commission poses several questions on the 100% abandoned plant cost recovery incentive.[37] This incentive, if granted, authorizes a transmission project developer to recover 100% of project costs for a project cancelled for reasons beyond the developer's control, subject to the requirement that the developer make a section 205 filing after the project is cancelled to establish that the project was in fact cancelled for reasons beyond the developer's control and that the costs the developer seeks to recover were prudently incurred. The Commission requests comments on whether this incentive should be granted automatically, and what consequences such a change might have on risk and evaluations of prudence.

AEP encourages the Commission to revise its policy to establish an automatic grant of the abandoned plant incentive for projects undertaken pursuant to an approved RTO transmission plan. For this subset of projects, it is the RTO's planning process, not the transmission owner's management, which has made the decision to undertake the project. The default FERC policy of allowing only 50% recovery of abandoned project costs is designed to discipline utility management decisions to start project spending. However, such discipline is not relevant for projects undertaken pursuant to a regional plan developed through an approved RTO transmission planning process. Under this changed approach, each developer still would be required to demonstrate to the Commission in a section 205 filing that the project was abandoned for reasons beyond the developer's control and that the costs incurred were prudent.

[36] *See, e.g., Commonwealth Edison Co.*, 167 FERC ¶ 61,173 at P 32 (2019).

[37] Incentives NOI at P 42, Questions 77-79.

Importantly, the recovery of abandoned plant costs is an incentive that continues to encourage the type of transmission infrastructure investment that the Commission has promoted and that Congress strove to incent in amending the FPA in 2005. Building transmission infrastructure comes with considerable risks and it is not uncommon for developers to have to abandon projects for reasons outside of their control. Allowing these entities to recover 100% of the prudently incurred costs of RTO-approved transmission projects that are cancelled for reasons outside of the developer's control will provide assurance to investors that costs will be recovered. The continued requirement that the developer demonstrate that costs were prudently incurred will provide discipline on the spending decisions made by the developer.

The Commission currently requires a project-by-project nexus showing to establish the need for the abandonment incentive. This policy should be changed to grant the incentive, without the need for an Order No. 679 filing, for projects undertaken pursuant to an RTO-approved transmission plan. By limiting the automatic grant of this incentive to those projects that are developed and approved through an RTO transmission planning process, there is little risk of transmission developers taking advantage of the availability of the incentive to undertake unnecessary or imprudent projects. This change in policy would advance the Commission's goals of incentivizing transmission development consistent with regional transmission planning undertaken by RTOs.

E. The Commission Should Grant Certain Non-ROE Incentives to New Entrant Transmission Developers upon Request.

The Commission also seeks comment on other risk-reducing non-ROE transmission incentives.[38] These incentives can be an important mechanism to help level the playing field for

[38] *Id.* at PP 40-41.

new entrants seeking to develop transmission projects assigned through a competitive developer selection process. For example, because new entrants, unlike established transmission owners, may have no means to collect expense in real time or have no pre-existing capital structure, the availability of a hypothetical capital structure and a regulatory asset to recover pre-commercial expenses helps such entities to secure the necessary financing for competitively assigned transmission projects. As the Commission notes, these incentives "reduce the financial and regulatory risks associated with transmission investment."[39] In practice, FERC has sometimes granted these incentives under section 205 of the FPA, because new entrant competitive developers often are seeking such incentives before a project has been assigned, and thus the nexus showing cannot be made under Order No. 679. Acting under section 205 allows the incentives to be granted to the new entrant competitive developer in advance of being assigned any particular project.

The Commission should adopt a policy of granting these incentives to new entrants upon request rather than requiring detailed incentive request filings that add costs for new entrants. As the Commission notes in the Incentives NOI, it already routinely grants these incentives for new entrants.[40] For regulatory assets, the subsequent FERC review of the costs included in the regulatory asset would still be required. By revising this policy, the Commission would further its policies supporting competitive transmission development articulated in Order No. 1000.

F. The Commission Should Permit Transmission-Owning Entities to Request Capital Treatment for Certain O&M Expenditures.

The Commission should be flexible in the types of incentives that may be requested. In some cases, such as participation in RTOs, an ROE adder is appropriate, while in other cases,

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39 *Id.* at P 40.

40 *Id.* at P 40 n.51.

different incentive rate treatments may be appropriate. One such rate treatment would be to allow expenses for projects that improve security or provide more flexible operations, such as vegetation management, transmission line patrols, cloud software applications, or data analysis, to be capitalized using a regulatory asset or otherwise.

For example, the Commission could permit applicants to request the recovery of specified O&M expenses as capital costs for ratemaking purposes in the area of forestry and vegetation management to encourage best-in-class practices. Effective vegetation management is vital to the reliability of the Bulk Power System, as evidenced by the 2003 Blackout.[41] Extreme weather conditions, whether it be excessive rainfall, drought or heat, is making traditional vegetation management more challenging while simultaneously increasing its importance. Vegetation management is an on-going and evolving challenge facing transmission owners as extreme weather conditions intensify, which only heightens importance of vigilance in preventing encroachment of vegetation to ensure the reliability of the grid. The NERC Reliability Standards applicable to vegetation management do not apply to facilities that are below 200 kilovolt. Vegetation management, therefore, should be considered as one of the most critical components to maintaining system reliability, and should be prioritized in a way that puts it on equal footing with transmission investment. Best-in-class vegetation management creates long-term system benefits by reducing outages.

The Commission could provide a greater incentive to adopt and implement state-of-the-art vegetation management practices by allowing transmission-owning entities to book the costs that currently would be categorized as O&M expense as a capital cost to be amortized over an

[41] *See* U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* at 59 (Apr. 2004), *available at* https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

appropriate period.[42] Treating these costs as capital would allow transmission owners to earn a return on the unamortized balances and thereby create an incentive to these entities to focus funds in this reliability-critical function. This incentive rate treatment would support the Commission's reliability goals and benefit customers by reducing outages over the long term.

By permitting applicants to capitalize certain O&M expenditures, the Commission could incent best practices for grid security and reliability that benefits all customers.

G. An Advanced Technology Incentive Should Encourage Cost-Saving Technology Enhancements to the Grid.

In the Incentives NOI, the Commission sought comment on incentives for the use of advanced technologies.[43] AEP supports the development of an incentive for the deployment of advanced technologies that allows a transmission owner to identify the technologies and investments that create the most savings for its unique system (and avoids picking winning or losing technologies), and encourages innovation and investment by sharing a portion of the demonstrated savings with the transmission owner. This approach to incentives for advanced technologies would further the Commission's goals of improved grid reliability and resilience by supporting deployment of new enhanced grid technology.

IV. CONCLUSION

AEP urges the Commission to: (1) continue to provide an RTO Participation Adder, and recognize that an increase in the current adder would be justified based on the very substantial

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[42] *See* FERC's Uniform System of Accounts, FERC 101 – Electric Plan Instruction. AEP suggests that Accounts 352, 356, and 359 are the possible accounts to consider for this capital expense.

[43] Incentives NOI at P 39, Questions 67-69. In a recent interview, Commissioner Glick emphasized the benefits of investing in existing assets to improve grid efficiency. David Roberts, "This Federal Agency is Quietly, Profoundly Shaping Climate Policy: A chat with Commissioner Richard Glick of the Federal Energy Regulatory Commission," Vox (May 22, 2019 10:00 AM), https://www.vox.com/energy-and-environment/2019/5/22/18631994/climate-change-renewable-energy-ferc. In a recent article published in the Energy Bar Journal, Commissioner Glick emphasized the increased efficiency of the grid as an important factor in integrating the changing resource mix on the grid. Rich Glick and Matthew Christiansen, *FERC and Climate Change*, 40 Energy B.J. 1, 36 (2019).

benefits RTOs provide to customers; (2) offer a Grid Resilience Incentive, to be based on a comprehensive company-specific Resilience and Security Action Plan; (3) grant the Abandonment Incentive automatically for developers of new transmission projects included in a regional transmission expansion plan; (4) grant to new entrant transmission developers upon request the Regulatory Asset and Hypothetical Capital Structure incentives; (5) permit transmission owners to request capital treatment for certain expenditures, such as the cost of state-of-the-art vegetation management programs; and (6) consider offering an advanced technology incentive that encourages cost-saving technology enhancements to the grid.

Please contact the undersigned with any questions concerning these comments.

Respectfully Submitted,

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