150 FERC ¶ 61,224
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
and Norman C. Bay.

Tallgrass Transmission, LLC	Docket Nos.	ER09-35-001
Prairie Wind Transmission, LLC		ER09-36-001
		(consolidated)

ORDER DENYING REHEARING

(Issued March 26, 2015)

1. This order addresses the request filed by Arkansas Electric Cooperative Corporation and Golden Spread Cooperative, Inc. (together, Cooperatives) for rehearing of the Commission's December 2, 2008 order.[1] In the Incentives Order, the Commission conditionally accepted and set for hearing and settlement judge procedures the tariff sheets that Tallgrass Transmission, LLC (Tallgrass) and Prairie Wind Transmission, LLC (Prairie Wind) (together, Applicants) had proposed for inclusion in the open access transmission tariff (Tariff) of the Southwest Power Pool, Inc. (SPP). The tariff sheets set forth formula rates and formula implementation protocols whereby each Applicant would recover the costs of the high voltage transmission project (Project) that it proposed to construct in the SPP region. The Commission also granted, in part, Applicants' requests for transmission rate incentives, pursuant to Order No. 679.[2] Additionally, the Commission summarily determined the base return on equity (ROE) for each Project and the associated range of reasonableness. For the reasons discussed below, we deny Cooperatives' request for rehearing.

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[1] *Tallgrass Transmission, LLC and Prairie Wind Transmission, LLC*, 125 FERC ¶ 61,248 (2008) (Incentives Order).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007). The Commission issued Order No. 679 in response to FPA section, 16 U.S.C. § 824s (2012).

I. Background

A. Description of Applicants

2. Tallgrass, an independent transmission company, is owned, in equal shares, by Electric Transmission America (Electric Transmission) and OGE Transmission, LLC, a subsidiary of OGE Energy Corp. (OGE Energy).[3]

3. Prairie Wind, an independent transmission company, is owned, in equal shares, by Electric Transmission and by Westar Energy, Inc., the company formed by the 1992 merger of Kansas Power and Light Company and Kansas Gas and Electric Company.[4]

B. Description of Proposed Projects

4. Applicants filed their respective applications on October 3, 2008 (Tallgrass Application (Docket No. ER09-35-000)) and (Prairie Wind Application (Docket No. ER09-36-000)), pursuant to section 205 and section 219 of the Federal Power Act (FPA).[5]

5. Tallgrass proposed to construct a 765-kV transmission project in Oklahoma (Tallgrass Project), comprising two segments. The first segment was expected to run from a new 765-kV substation near Woodward, Oklahoma (Woodward Substation), to a new 765-kV substation on the Oklahoma-Texas border. The second segment was expected to run from the Woodward Substation to the Oklahoma-Kansas border and to

[3] Tallgrass Application at 7-8. Electric Transmission is a joint venture between wholly-owned subsidiaries of American Electric Power Company, Inc. and MidAmerican Energy Holdings Company. OGE Energy is also the parent corporation of Oklahoma Gas and Electric Co. (OG&E), a public utility providing electric service to customers throughout Oklahoma.

[4] Prairie Wind Application at 7-8.

[5] 16 U.S.C. §§ 824d, 824s (2012). Section 219 requires the Commission to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. The Commission implements this requirement pursuant to Order No. 679.

interconnect with Prairie Wind's Project. The proposed facilities were estimated to cost approximately $500 million.[6]

6. Prairie Wind proposed to construct approximately 230 miles of a 765-kV transmission project in Kansas comprising two segments in the shape of a "Y" (Prairie Wind Project). The first segment would consist of approximately 230 line miles of 765-kV transmission facilities, configured in a "V" shape, running, in a southwesterly direction, from a substation near Wichita to a new substation near Medicine Lodge (Medicine Lodge Substation) and then west-northwest to a substation near Spearville. The second segment, the base of the "Y," would run from the Medicine Lodge Substation south to the Kansas-Oklahoma border and would interconnect with the proposed Tallgrass Project. Prairie Wind estimated that the proposed facilities would cost approximately $600 million.[7]

C. <u>Applicants' Support for Transmission Incentives</u>

7. Applicants stated that the Tallgrass and Prairie Wind Projects will improve reliability, eliminate existing and anticipated congestion on the transmission system, reduce losses, and permit the interconnection of substantial quantities of wind generation. This new wind generation will provide substantial environmental, economic, and security benefits by, for example, reducing the demand for fossil fuels and thus air pollution, reducing the use of water in electric generation, increasing generation resource diversity, and creating new jobs and income sources for rural residents.[8]

8. Applicants also asserted that the Tallgrass and Prairie Wind Projects are consistent with SPP's vision of a high voltage grid to "overlay" the existing SPP transmission grid. SPP had commissioned studies to evaluate the effect of intensifying wind development activity in portions of SPP and to examine potential routes for the first 765-kV projects to be included in the high voltage grid overlay.[9] Applicants asserted that the Projects are

[6] Tallgrass Application at 1, 10-11.

[7] Prairie Wind Application at 1, 11.

[8] Tallgrass Application at 14-15; Prairie Wind Application at 15-16.

[9] In January 2007, SPP commissioned Quanta Technology, LLC (Quanta) to: (1) perform a strategic assessment regarding the long-term reliability and capacity needs through the use of a 345-kV, 500-kV, and 765-kV or higher voltage transmission system to overlay the existing transmission system within the SPP footprint; (2) assess SPP's potential integration with neighboring systems to address future transmission needs required by SPP; and (3) ensure an efficient and optimal transmission system to address

(continued…)

almost identical to facilities included in the two scenarios recommended in the Quanta Study. Moreover, the Quanta Study recommended sequencing of construction of the EHV Overlay that begins in the western portion of the SPP system and expands eastward. The construction of the planned high voltage overlay was broken down into three "packages," with the first package further broken down into three steps. Applicants' Projects were reflected in package one - step one of the construction sequence. The Quanta Study showed that this construction sequencing was best because wind development was already occurring in the western portion of the SPP system, there was a lack of transmission from west to east to deliver this energy, and western portions of the SPP system have been authorized to proceed with development to deliver the wind generation to load centers.[10]

9. Applicants commissioned their own study to analyze the potential benefits of constructing the initial core section of SPP's EHV Overlay, which includes the Tallgrass and Prairie Wind Projects.[11] The CRA Study evaluated constructing the two high voltage transmission loops, which include the Projects. The study showed that the two loops could enable the interconnection of at least 14,000 MW of cost-effective wind power, which would permit SPP to wheel 20 percent of its power from renewable energy sources by 2016. Applicants stated that, according to the CRA Study, these two loops, of which the Projects would be a portion, would create $628-728 million in annual net power

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long-term future transmission needs. Quanta performed the study and published its initial report on June 21, 2007. Subsequently, Quanta updated the study to evaluate the effect of increased wind development on the SPP system. Quanta developed and compared four overlay designs and developed a construction sequence for the extra high voltage overlay (EHV Overlay). Quanta published its updated study on March 3, 2008. Quanta, *Final Report on the Southwest Power Pool (SPP) Updated EHV Overlay Study*, March 3, 2008 (Quanta Study). *See* Tallgrass Application at Ex. No. TGT-102; Prairie Wind Application at Ex. No. PWT-101.

[10] Incentives Order, 125 FERC ¶ 61,248 at P 7.

[11] Applicants commissioned CRA International, Inc. to analyze the potential benefits of constructing two 765-kV transmission loops in Kansas, Oklahoma, and northern Texas, including the Tallgrass and Prairie Wind Projects, as an initial phase of establishing the SPP EHV Overlay. *See* CRA International, Inc., *First Two Loops of SPP EHV Overlay Transmission Expansion; Analysis of Benefits and Costs*, September 26, 2008 (CRA Study). Tallgrass's and Prairie Wind's Applications at Ex. Nos. TGT-103 and PWT-103, respectively. While the CRA Study's two-loop project is not identical to the Quanta Study, the two loops are in the western portion of the SPP system and contain the Tallgrass and Prairie Wind Projects.

supply benefits for the SPP region, which includes $100 million in annual savings through reductions in energy losses by using 765-kV transmission technology.[12]

10. Applicants stated that, while the CRA Study did not analyze the benefits of the Projects on a stand-alone basis, it provided a strong basis for finding that the Projects satisfy the eligibility requirements for rate incentives under section 219. They asserted that they will have to be successful if proponents are going to be willing to step forward and construct the rest of the EHV Overlay, and that Commission support for the Projects will signal other project developers to move forward.[13]

11. Applicants acknowledged that the Tallgrass and Prairie Wind Projects had not yet been approved for inclusion in the SPP regional transmission expansion plan and had not yet received all necessary siting approvals. However, Applicants expected SPP to approve the EHV Overlay and to file, with the Commission, a proposal to allow 765-kV facilities, like the Projects, to be included in SPP transmission rates.[14]

D. Rate Proposals and Incentives Requests

12. Applicants made identical rate proposals consisting of a formula rate with formula rate implementation protocols to recover their projected costs under the SPP Tariff, subject to true-up. Applicants also requested four rate incentives for their investments in the proposed Projects. They requested an ROE incentive rate of 13.3 percent, which included incentive adders for participation in a regional transmission organization (RTO), new technology, and investing in substantial new transmission facilities that, they argued, would reduce the cost of electricity and promote the public interest by providing for the interconnection and delivery of renewable generation in SPP. They requested the inclusion of 100 percent of construction work in progress (CWIP) in rate base during the development and construction period of the Projects after the formula rate became effective. They requested the abandoned plant incentive to allow them to recover their prudently-incurred investment costs in the Projects in the event that the Projects were abandoned for reasons outside of their control. They sought permission to establish a regulatory asset that included all expenses not included in CWIP that had been incurred to date as well as expenses incurred going forward until the formula rate became effective and they received Commission authorization to recover the regulatory asset over

[12] Tallgrass Application at 17-18; Prairie Wind Application at 19-20.

[13] Tallgrass Application at 18-19; Prairie Wind Application at 20-21.

[14] Tallgrass Application at 3; Prairie Wind Application at 3.

five years. In addition, Applicants requested a hypothetical capital structure for use during the construction period.[15]

E. Incentives Order

13. In the Incentives Order, the Commission granted certain of the transmission rate incentives that Applicants had requested. It also conditionally accepted the tariff sheets, and established hearing and settlement judge procedures, but summarily resolved certain issues. The determinations for which Cooperatives request rehearing are: (1) requests for incentive rate treatment were not premature; (2) Applicants had demonstrated that the Projects will reduce the cost of delivered power; (3) Applicants qualified for a grant of the abandoned plant incentive; (4) Applicants' use of a hypothetical capital structure consisting of 50 percent debt and 50 percent equity was appropriate; and (5) while certain rate issues were set for hearing and settlement judge procedures, the Commission could decide, on the basis of the record and Commission precedent, the appropriate proxy group, the range of reasonableness for the return on equity (ROE),the base ROE, and the basis-point incentive adder for the ROE. We address these issues below.

F. Post-Incentives Order Events

14. On May 10, 2010, Applicants filed, with the Commission, settlement agreements stating that the parties had settled all issues in these proceedings except for the issues raised in Cooperatives' request for rehearing.[16] On September 13, 2013, Tallgrass submitted an informational filing stating that it will not construct its Project and will not seek to implement any of the transmission rate incentives granted by the Incentives Order.[17]

II. Rehearing Request and Commission Determinations

15. In their January 2, 2009 rehearing request, Cooperatives contend that, in the Incentives Order, the Commission erred in nine issues. The first five issues pertain to the requested transmission incentives: (1) the Commission should have deferred action on Applicants' requests for incentive rate treatment until their proposals were fully vetted in

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[15] Tallgrass Application at 3-4; Prairie Wind Application at 3-4.

[16] On August 9, 2010, the Commission approved the settlements. *Tallgrass Transmission, LLC* and *Prairie Wind Transmission, LLC,* 132 FERC ¶ 61,114 (2010).

[17] Tallgrass September 30, 2013 Informational Filing at 1, 3 (Tallgrass September 2013 Filing).

the SPP regional planning process; (2) the Commission lacked adequate evidence to find that the Projects will reduce the cost of delivered power and thus are eligible for transmission incentives; (3) the Commission failed to follow its precedent when finding that the Projects will reduce the cost of delivered power and failed to provide a reasoned explanation for not following this precedent; (4) the Commission failed to address Cooperatives' arguments against granting the Projects the abandonment transmission rate incentive; and (5) the Commission erred in accepting Applicants' hypothetical capital structures. The last four issues concern the proposed ROE: (6) the Commission should have set for hearing Applicants' proposed ROE and associated incentive adders; (7) the Commission failed to provide a reasoned basis for summary disposition of ROE issues; (8) the Commission failed to address Cooperatives' disputed issues of material fact concerning the ROE issues; and (9) the Commission acted arbitrarily when it summarily approved Applicants' ROE proposals, after having modified them, because the Commission failed to provide parties with an opportunity to respond to the supplemental ROE evidence upon which it had relied for summary approval.

16. As noted above, in the Tallgrass September 2013 Filing, Tallgrass explained that it decided not to construct the Tallgrass Project because SPP issued a Notification to Construct to OG&E to build at 345 kV the facilities proposed by Tallgrass.[18] Consequently, Tallgrass will not seek to implement any incentives and we find that the rehearing requests, as they pertain to Tallgrass, to be moot. While we are aware that the Prairie Wind Project has changed in size and scope since issuance of the Incentives Order, this order addresses requests for rehearing of the Incentives Order. The changes do not necessarily alter the basis for the Commission's previous grant of transmission incentives.[19] Therefore, our deliberations as to the reasonableness of the Commission's findings and determinations in the Incentives Order are based on the record that was before the Commission when it acted on the requested transmission incentives, in December 2008. To do otherwise would contribute to unnecessary confusion and uncertainty, and it might prompt project developers to delay construction of their transmission projects until the Commission has acted on rehearing requests.

[18] Tallgrass September 2013 Filing at 3.

[19] *Accord Pioneer Transmission, LLC*, 130 FERC ¶ 61,044, at P 21 (2010) (*Pioneer Transmission*). To the extent that Cooperatives believe that the modifications to the Prairie Wind Project render invalid the basis for the transmission incentives granted in the Incentives Order, the Cooperatives or any other entity may raise these concerns in a proceeding under section 206 of the FPA, 16 U.S.C. § 824e (2012).

A. Timeliness of Incentives Grant

1. Incentives Order

17. The Commission addressed objections that the Applications and Applicants' requests for incentive rate treatment were premature.[20] The Commission found that Applicants had met the requirements of section 219 for incentives eligibility[21] by demonstrating that the facilities for which they sought incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[22] Thus, the Commission, in the Incentives Order, found that Applicants' requests for incentive rate treatment were not premature but were consistent with section 219's requirements for incentives eligibility.

18. The Commission relied on Applicants' choice to pursue projects recommended through independent assessments of the long-term needs of the entire SPP region. The Quanta Study and CRA Study had concluded that substantial power production cost savings would be due in substantial part to increased transfer capability that would reduce congestion and allow transportation of low-cost wind energy to displace higher cost energy from fossil fuel sources. Based on these studies, the Commission found a reasonable basis for concluding that Applicants' Projects will reduce congestion by facilitating integration and delivery of low-cost wind energy in the SPP region.[23]

19. The Commission answered objections that the SPP high voltage overlay could change significantly in the regional planning process, thus requiring changes to the Prairie Wind Project, and that a competing project proposed by ITC Great Plains, LLC (ITC Great Plains) had progressed further than the Prairie Wind Project and was already reflected in SPP's transmission expansion plan. The Commission explained that the issue of whether these Projects are the best solution or whether competing projects are entitled to incentives is not the issue in this proceeding. Commission policy, it stated, is to review each request for incentives on its own merits and on a case-by-case basis. Thus, it was reviewing only whether the Projects meet the Commission's requirements for

[20] Incentives Order, 125 FERC ¶ 61,248 at PP 30-35.

[21] *Id.* P 40.

[22] *Id.* P 28 & n.20 (citing 35 C.F.R. § 35.35(i)(2) (2014)).

[23] *Id.* P 41.

incentives.[24] It stated that the appropriate forum to address whether one or more competing projects should be built is through the regional planning process and appropriate state siting process.[25]

20. The Commission stated that neither cost allocation study nor cost-benefit analysis is required for eligibility for incentives under section 219 or Order No. 679. It found also that its action would not undermine the SPP stakeholder process, which, it observed, is "open and transparent." It stated that nothing in the Incentives Order "changes SPP's process or the manner in which SPP evaluates projects."[26]

21. The Commission considered whether Applicants satisfied the "nexus test" of Order No. 679-A, which is met when an applicant demonstrates that the total package of incentives it requested is "tailored to address the demonstrable risks or challenges faced by the applicant,"[27] and where the question of whether a project is "routine" is particularly probative.[28] It determined that Applicants had sufficiently demonstrated a nexus between their proposed Projects and the requested incentives, and that the Projects are not routine, based on the Projects' scope, effects, and risks and challenges.[29] It stated that "the proposed 765-kV Projects are exceptional in both size and purpose and will facilitate the interconnection and transport of at least 5800 MW of the approximately 40,000 MW new renewable power currently in SPP's queue with the potential for the interconnection of additional renewable power that is currently constrained by the limitations of the transmission system."[30] It noted several important factors in its consideration: the Projects "will entail regulatory risk associated with obtaining the necessary approvals from two state commissions as well as inclusion and approval in the

[24] *Id.* P 42 (citing *Pacific Gas & Elec. Co.*, 123 FERC ¶ 61,067 (2008) (*Pacific*); *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008), *reh'g denied*, 135 FERC ¶ 61,136 (2011) (*Central Maine I*)).

[25] *Id.* P 57.

[26] *Id*. P 43 (citations omitted).

[27] *Id*. P 44 (citing Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40).

[28] *Id.* & n.41 (citing *Baltimore Gas and Elec. Co.*, 120 FERC ¶ 61,084, at PP 52-55 (2007), *reh'g denied*, 122 FERC ¶ 61,034 (2008) (*Baltimore*)).

[29] *Id.* P 53.

[30] *Id.* P 54.

SPP transmission expansion plan," and that the Projects presented significant capital investment for the Applicants totaling approximately $1.1 billion.[31]

2. Rehearing Request

22. On rehearing, Cooperatives continue to assert that the Commission's grant of transmission incentives to the Projects is premature because the proposed Projects had not yet been considered under SPP's regional planning processes. They point out that the grant of incentives undercuts the Commission's findings regarding the importance of regional planning. Cooperatives cite the Commission's statements, in adopting Order No. 890[32] and in accepting SPP's compliance filing of Attachment O, "Transmission Planning Process," to the SPP Tariff, that SPP's customers and other stakeholders must have the opportunity to participate fully in the planning process so as to avoid unlawful discrimination, and that this participation should be early in the process.[33]

23. Cooperatives' rehearing request includes a December 11, 2009 letter from Prairie Wind to the Kansas Corporation Commission (Kansas Commission) (Prairie Wind 2009 Letter) in which Prairie Wind proposes that responsibility to build the 765-kV facilities in Kansas be split between Prairie Wind and ITC Great Plains. As a result of this split in responsibility, Prairie Wind will construct a re-configured 200 miles of 765-kV line and ITC Great Plains will construct 180 miles of transmission line, part of which may be built at 345-kV.[34] Cooperatives state that because this revised Prairie Wind proposal is

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[31] *Id*. P 56.

[32] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (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 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[33] Rehearing Request at 7-8 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 435; *Southwest Power Pool, Inc.*, 124 FERC ¶ 61,028, at P 12 (2008)).

[34] Rehearing Request at 8-9 & Attachment 1. The Commission notes that subsequent filings, by Prairie Wind, ITC Great Plains, and SPP, demonstrate that Prairie Wind and ITC Great Plains did combine efforts to construct new transmission in Kansas. Prairie Wind constructed 345-kV lines between the Kansas-Oklahoma state line and Prairie Wind's Thistle Substation and from the Thistle Substation to Wichita. ITC Great Plains constructed 345-kV transmission lines from the Thistle Substation to Spearville. *See* SPP, Submission of Transmission Interconnection Agreement, Docket No. ER14-1304-000, at Ex. A, Interconnection Nos. 1, 2 (filed Feb. 11, 2014); Prairie Wind, Docket

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materially different from the Project proposed in the Prairie Wind Application and is not before the Commission, there is no basis for finding that such a project meets the requirements of section 219 – that the Project would either ensure reliability or reduce the cost of delivered power to those transmission users who will be charged for the cost of the project. Additionally, Cooperatives argue that bringing in an additional partner and reducing the extent of the facilities for Prairie Wind to construct reduces the risk associated with Prairie Wind's investment. Thus, Cooperatives contend that the change in the Project's scope and configuration casts doubt on whether the Project can support the base ROE and the level of transmission incentives to be awarded to Prairie Wind. The revised proposal, conclude Cooperatives, demonstrates that the Commission's consideration of transmission incentives was premature.[35]

3. Commission Determination

24. We find that the transmission incentives awarded to Applicants were not premature, and we deny rehearing on this issue. In acting on requests for transmission incentives, the Commission examines whether the project reduces congestion or ensures reliability, and determines whether there is a nexus between the transmission incentive sought and the investment being made.

25. In the Incentive Order, the Commission acknowledged that the projects had not been approved as part of SPP's transmission expansion plan and did not qualify for the rebuttable presumption. However, in Order No. 679,[36] the Commission stated that projects may still be eligible for incentives even without the rebuttable presumption if the applicants can demonstrate that the projects will result in improved reliability or a reduction in the cost of delivered power. In the Incentives Order, the Commission determined, based on the Quanta Study and the CRA Study,[37] that the SPP overlay, of which these projects were expected to be a part, would result in a reduction of the cost of

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No. ZZ10-3-000, FERC Form No. 730 Report of Transmission Investment Activity, at Table 2 (filed Apr. 4, 2014) (Prairie Wind April 2014 Report); ITC Great Plains, Docket No. ZZ11-3, FERC Form No. 730 Report of Transmission Investment Activity, at Table 2 (filed Apr. 18, 2011).

[35] Rehearing Request at 8-9.

[36] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 57 (applicants not meeting criteria for rebuttable presumption may nonetheless demonstrate that their project is needed to maintain reliability or reduce congestion by presenting us a factual record that would support such findings).

[37] *Supra* PP 8-9.

delivered power. As Tallgrass and Prairie Wind stated, the projects, and by extension the incentives on the projects, would not move forward without inclusion in the SPP transmission expansion plan and the acquisition of the necessary regulatory approvals.[38] Thus, the Commission's granting of incentives in these proceedings prior to review in the SPP regional planning process was reasonable.

26. Furthermore, Order No. 679 specifically permits the Commission to evaluate for reliability or congestion relief projects that are undergoing consideration in a regional planning process. The Commission may make any requested rate treatment contingent upon the project receiving such approval.[39] In this proceeding, the Commission had before it Applicants' statements that most of the requested transmission incentives would become moot unless their Projects were included in the SPP regional transmission plan and received regulatory approvals from the Kansas Commission.[40]

27. Relying on the results of the Quanta Study and the CRA Study, the Commission found that the Projects met the requirements of section 219. These studies found that the Projects would result in substantial power production cost savings, due in large part to increased transfer capability, would reduce congestion, and would allow transportation of low-cost wind energy to displace higher cost energy from fossil fuel sources. These studies provide a reasonable basis for the Commission's conclusion that Applicants' proposed Projects would reduce congestion by facilitating integration and delivering low-cost wind power energy in the SPP region.[41]

28. We disagree with Cooperatives that granting the transmission incentives before consideration of the Projects in the SPP regional planning process undercuts the Commission's policies regarding the importance of such planning processes. In the Tallgrass September 2013 Filing, Tallgrass explained that it decided not to construct the Tallgrass Project because SPP's regional transmission process resulted in the issuance of a Notification to Construct for OG&E to build facilities at 345 kV.[42] In the Prairie Wind April 2014 Report, Prairie Wind stated that its Project had changed from 765 kV to

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[38] Incentives Order, 125 FERC ¶ 61,248 at P10 (citing Tallgrass Application at 3).

[39] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58 n.39.

[40] Incentives Order, 125 FERC ¶ 61,248 at P 36. *See also* Tallgrass November 10, 2008 Filing at 3; Prairie Wind November 10, 2008 Filing at 3.

[41] Incentives Order, 125 FERC ¶ 61,248 at P 41.

[42] Tallgrass September 2013 Filing at 3.

345 kV pursuant to direction from SPP.[43] Thus, SPP's regional planning process worked as intended. SPP independently considered competing projects and chose the particular project size and scope that it considered to be best for the SPP region.

29. We find speculative Cooperatives' argument that a revised Prairie Wind Project would be less risky and possibly obviate the need for transmission incentives. The Commission will not grant rehearing based on a speculative proposal in the Prairie Wind 2009 Letter that the Kansas Commission had not addressed. The record before the Commission at the time that Cooperatives filed their rehearing request lacked specific details regarding changes to the Prairie Wind Project and any associated changes in risks. Moreover, the Prairie Wind 2009 Letter describes the Prairie Wind Project as comprising 765-kV facilities.

B. Cost of Delivered Power

1. Incentives Order

30. Relying on the findings of the Quanta Study and the CRA Study, the Commission concluded that Applicants had demonstrated that the Projects met the requirements of section 219 and would reduce congestion, in part, because they would facilitate integration and delivery of low-cost wind power in the SPP region. These studies found substantial power production cost savings due in large part to increased transfer capability that would reduce congestion and allow transportation of low-cost wind energy to displace high cost energy from fossil fuel sources. The Commission added that, with SPP's proposed high voltage overlay, lower voltage facilities will be relieved of their congestion resulting in a reduction in the cost of delivered power.[44]

2. Rehearing Request

31. Cooperatives dispute the Commission's finding that the Projects will reduce the cost of delivered power and allege that this finding is not supported by substantial record evidence. Cooperatives assert that neither the Quanta Study nor the CRA Study evaluated the effect of the proposed Projects; rather, they examined the impact of the whole two-loop project, of which the Tallgrass and Prairie Wind Projects are only a part.

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[43] Prairie Wind April 2014 Report at Table 2, Project Detail.

[44] Incentives Order, 125 FERC ¶ 61,248 at P 41 & n.35.

Further, continue Cooperatives, the two studies did not look at nor reach any conclusions regarding the cost of delivered power.[45]

32. Cooperatives contend that a finding that the Projects will reduce the cost of delivered power cannot be made because no power to deliver yet exists; the record does not contain any specific proposed generation units whose power the Projects would deliver, and no specific customers have requested construction of the Projects. The future cost of delivered power after construction of the Projects cannot be calculated because there is no current cost of delivered power for comparison.[46] Cooperatives assert that the Quanta and CRA Studies do not show that the Cooperatives will experience a reduction in the cost of delivered power and that this is true for every other load-serving entity in SPP. Cooperatives state that the record is without evidence to show an effect on any wholesale or retail customer, and that the finding that the Projects will reduce congestion by facilitating integration and delivery of low-cost power is unsupported by record evidence of the costs of the Projects or their probable effect on the cost of delivered power. They contend that justification of a conclusion about reduced cost of delivered power needs an accompanying finding that the reduction in congestion would outweigh the added cost of transportation.[47] Cooperatives contend that, lacking support for a finding that the Projects will reduce the cost of delivered power, the Incentives Order violates section 219, the Commission's regulations, and the Commission's precedent.

3. Commission Determination

33. We deny rehearing on this issue. The Commission evaluated the Quanta Study and the CRA Study and agreed with their conclusions that increased transfer capability would both reduce congestion and allow low-cost wind energy to displace high cost energy from fossil fuel sources. The Commission determined that the plans considered by the studies reasonably forecast an expanded SPP transmission system including Applicants' Projects. Thus, we affirm the finding in the Incentives Order that the studies provide a reasonable basis to conclude that the Projects will reduce congestion in the SPP region.[48]

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[45] Rehearing Request at 10.

[46] *Id*. at 10-11.

[47] *Id.* at 12-13.

[48] Incentives Order, 125 FERC ¶ 61,248 at P 41.

34. While the Cooperatives are correct that the studies submitted do not demonstrate a reduction in the cost of delivered power for each individual load-serving customer in SPP, the Cooperatives are mistaken that such a showing is necessary for a proposed project to be eligible for transmission incentives. Section 219 requires either a demonstration of improved reliability or a reduction in the cost of delivered power, but it does not require such a showing for each individual load-serving customer.[49] Concerning Cooperatives' request that we require comparison of reduction in congestion to additional transmission costs, Order Nos. 769 and 769-A rejected requests to make grants of transmission incentives contingent on cost-benefit analysis.[50]

C. Eligibility for Transmission Incentives

1. Incentives Order

35. As discussed above, in the Incentives Order, the Commission found that the Applications met the requirements of section 219 for transmission incentives eligibility and had not been filed prematurely. The Commission granted the request for inclusion of 100 percent of CWIP in rate base during the development and construction period of the project after the formula rate becomes effective.[51] The Commission also determined the applicable ROE[52] and specifically denied the request to decrease the ROE to reflect its decision on CWIP and its grant of an abandoned plant incentive.[53]

2. Rehearing Request

36. On rehearing, Cooperatives dispute these determinations. They argue that these determinations are premature or unsupported, and that the Commission failed to provide

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[49] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 57 (applicants may demonstrate that their project is needed to maintain reliability or reduce congestion by presenting the Commission a factual record that would support such findings).

[50] *Central Maine Power Company*, 125 FERC ¶ 61,182 at P 80 (2008) (*Central Maine II*) (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 80; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at PP 35-40). *See also Northeast Utilities Service Co.*, 125 FERC ¶ 61,183, at P 79 (2008).

[51] Incentives Order, 125 FERC ¶ 61,248 at PP 2, 67.

[52] *Id*. PP 58-61.

[53] *Id.* P 61.

a reasoned explanation of them which, Cooperatives claim, is required because the determinations fail to follow precedent. In support of their claims, Cooperatives cite *Pacific*[54] for the proposition that when a project is in the early stage of development, the Commission will defer granting CWIP and ROE transmission incentives. Cooperatives also cite *Southern California Edison Co.*[55] for the proposition that the grants of the CWIP and abandoned plant transmission incentives reduce an applicant's overall risk for the further transmission incentives of pre-commercial cost recovery and an enhanced ROE.[56]

3. Commission Determination

37. We deny rehearing. The Commission has already addressed these claims in the Incentives Order.[57] Moreover, Cooperatives' reliance on *Pacific* and *Southern California* is unavailing. Commission policy, as the Incentives Order stated, and as stated in *Pacific*, is to review each request for incentives on its own merits and on a case-by-case basis.[58] Additionally, as stated in the Incentives Order, a generic rule reducing ROE when incentives that mitigate risk are granted might encourage companies to anticipate such a reduction and to compensate by requesting a higher ROE.[59]

38. Moreover, in *Pacific*, the Commission granted the applicant's requests for the transmission incentives to recover prudently incurred abandonment costs and prudently incurred pre-commercial costs.[60] In *Pacific*, the Commission deferred consideration of the applicant's requests for the CWIP and ROE incentives because the applicant had not completed the necessary studies to demonstrate that its project meets the requirements of section 219 and Order No. 679.[61] Unlike the applicant in *Pacific*, Applicants here have

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[54] *Supra* note 24.

[55] *Southern California Edison Co.*, 121 FERC ¶ 61,168, at P 143 (2007), *reh'g denied*, 123 FERC ¶ 61,293 (2008) (*Southern California*).

[56] Rehearing Request at 13-14.

[57] Incentives Order, 125 FERC ¶ 61,248 at PP 2, 40-43, 58-61, 67.

[58] *Id.* P 42; *Pacific*, 123 FERC ¶ 61,067 at P 39.

[59] Incentives Order, 125 FERC ¶ 61,248 at P 61.

[60] *Pacific*, 123 FERC ¶ 61,067 at PP 36-37.

[61] *Id.* P 40.

submitted the necessary studies and demonstrated reduction in congestion. Concerning *Southern California*, the Commission reduced the applicant's requested ROE based on the facts presented in that case.[62]

D. Abandonment Costs

1. Incentives Order

39. The Commission granted Applicants' request to recover 100 percent of prudently incurred abandonment costs if the Projects are abandoned for reasons beyond Applicants' control. It stated that this is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs and will help Applicants finance their Projects. The Commission cited Applicants' understanding of the requirement that they make an additional section 205 filing before recovering abandoned plant costs and found that Applicants must demonstrate that such abandoned plant costs are just and reasonable.[63]

2. Rehearing Request

40. Cooperatives object to the Commission's grant of the abandonment cost recovery incentive. They contend that, in the Incentives Order, the Commission did not address their argument that regulated entities that have never provided transmission service are unable to collect transmission charges. Cooperatives point out that the Projects are not yet under the SPP Tariff and that, if they are abandoned before they enter service, the Applicants will never have provided transmission service or had any customers. Cooperatives contend that the Incentives Order's grant of the abandonment incentive is contrary to law and precedent.[64] Cooperatives rely on *AES Somerset, LLC v. Niagara Mohawk Power Corp*. for its holding that a utility must actually be providing a service before it can levy charges.[65]

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[62] *Southern California*, 121 FERC ¶ 61,168 at P 143.

[63] Incentives Order, 125 FERC ¶ 61,248 at P 62 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163).

[64] Rehearing Request at 15.

[65] *Id.* at 15-16 (citing *AES Somerset, LLC v. Niagara Mohawk Power Corp.*, 105 FERC ¶ 61,337, at P 42 (2003), *reh'g denied*, 110 FERC ¶ 61,032 (2005), *aff'd sub nom. Niagara Mohawk Power Corp. v. FERC,* 452 F.3d 822 (D.C. Cir. 2006)).

41. Cooperatives contend that, while the Commission acknowledged Cooperatives' argument, it did not address the argument, thus failing to provide a coherent and adequate explanation of its decisions. According to Cooperatives, the Commission should either determine that Applicants may not recover abandonment costs or any other costs from entities with whom they have no privity of contract or tariff, and to whom they have never provided transmission service, or state its reasons for rejecting Cooperatives' argument.

3. Commission Determination

42. We find premature Cooperatives' argument about cost recovery in the event of abandonment. The Incentives Order did not decide the sources from which Applicants could recover any prudently incurred abandonment costs that the Commission might grant in a future proceeding. That question would be an issue for the future proceeding, under section 205, where an Applicant seeks such recovery, as Applicants themselves recognized.[66]

43. The Commission's ruling on recovery of abandonment costs, in the Incentives Order, rested on whether Applicants had demonstrated a sufficient nexus, as required by Order No. 679-A, between the risks of their Projects and the need to recover prudently incurred costs associated with abandonment of their Projects.[67] The Commission found that Applicants had provided this demonstration. Relying on the factors set forth in *Baltimore Gas and Electric Co.*,[68] i.e., siting, long lead time, regulatory risks, unusual financing challenges, and other similar impediments, the Commission examined whether the proposed Projects were routine and found that they were not, based on their scope, effects, risks, and challenges.

44. The Commission referred to the proposed 765-kV Projects' purpose to facilitate the interconnection and transmission of at least 5800 MW of the approximately 40,000 MW new renewable power currently in the SPP queue, with the potential for the interconnection of additional renewable power that is currently constrained by the

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[66] Prairie Wind Application, Ex. No. PWT-600 at 13; Tallgrass Application, Ex. No. TGT-500 at 13.

[67] Incentives Order, 125 FERC ¶ 61,248 at P 44 (citing Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40); *see also, e.g., Central Maine II*, 125 FERC ¶ 61,182 at P 99.

[68] Incentives Order, 125 FERC ¶ 61,248 at P 55; *Baltimore*, 120 FERC ¶ 61,084 at PP 52-55.

limitations of the transmission system. The Commission repeated that the recovery of abandonment costs is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs.[69]

45. For these reasons, we find that the Commission did not err in granting the abandoned plant cost recovery incentive. If either Project were to be abandoned and a section 205 filing made, Cooperatives or other entities would be able to raise their concern in that proceeding, as the Incentives Order stated.[70]

E. Hypothetical Capital Structures

1. Incentives Order

46. Citing Order No. 679-A and Commission precedent, the Commission stated that the use of hypothetical capital structures can be an appropriate ratemaking tool for fostering new transmission in certain relatively narrow circumstances.[71] It found appropriate Applicants' proposal to use a hypothetical capital structure consisting of 50 percent debt and 50 percent equity during construction. The Commission determined that, during construction, Applicants' capital structure will be fluid, with financing available through the issuance of stock or borrowing, and that without a hypothetical capital structure, Applicants would need to track the constantly changing capital structure, which is complicated and can result in unpredictable cash flows. In the Incentives Order, the Commission concluded that the requested hypothetical capital structure will provide certainty and improve chances for more favorable terms from lenders.

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[69] Incentives Order, 125 FERC ¶ 61,248 at P 39; *see, e.g.*, *Central Maine II*, 125 FERC ¶ 61,182 at 97; *Central Maine I*, 125 FERC ¶ 61,079 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163).

[70] We point out that events since the Incentives Order have made moot the issue of plant abandonment cost recovery. Tallgrass stated that it will not seek to implement the abandoned plant incentive. Tallgrass September 2013 Filing at 3. Prairie Wind reported, in April 2014, that the Prairie Wind Project was under construction with an expected project completion date of December 2014. Prairie Wind April 2014 Report at Table 2. *See supra* note 34.

[71] Incentives Order, 125 FERC ¶ 61,248 at P 68 (citing Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 93).

2. **Rehearing Request**

47. On rehearing, Cooperatives once again object to the hypothetical capital structure, based on Applicants having provided no projections of expected capital infusions. Cooperatives contend that granting the request for a 50 percent debt and 50 percent equity hypothetical capital structure offers Applicants an opportunity to overcharge their customers by borrowing money and then charging customers the higher cost of equity, including the associated tax burden, for the amount borrowed.[72]

48. Cooperatives characterize the Commission's reasons for granting the hypothetical capital structure as "perfunctory." According to Cooperatives, the Commission did not adequately explain its reasons for granting the hypothetical capital structure, and did not consider the possibility that customers would be overcharged.[73] Cooperatives contend that Applicants will be required to track the actual capital structure in any event because meeting their principal and interest payment obligations to creditors mandates the timely tracking of debt service obligations. Cooperatives add that a formula rate can be designed to accommodate shifts in the capital structure. Cooperatives allege that the Commission adopted the hypothetical capital structure because this methodology is less complicated than tracking actual capital infusion. They assert that the Commission failed to explain why simplicity in rate-making is more important than ensuring that customers do not pay more than actual cost for the capital needed to build the Projects. They contend that the Incentives Order did not explain why approval of a hypothetical capital structure will improve the chances for more favorable terms from lenders. They argue that, if Applicants are permitted to include the actual cost of debt in their capital structure, and if they manage the Projects prudently, Applicants will be able to repay their lenders. Cooperatives contend that approval of hypothetical capital structures for Applicants will guarantee financial windfalls for these regulated utilities, and that such approval conflicts with the Commission's statutory purpose of assuring just and reasonable rates. They ask the Commission to require that the formula rate track the actual capital structure.[74]

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[72] Rehearing Request at 16.

[73] *Id.* at 17 (citing *PSEG Energy Resources & Trade, LLC v. FERC*, 360 F.3d 200, 203 (D.C. Cir. 2003)).

[74] *Id.* at 17-18.

3. **Commission Determination**

49. Cooperatives state:

> incorporating an arbitrary capital structure – whether 50:50, 90:10, or 10:90 – is unquestionably less complicated than tracking actual capital infusion [and] the Commission fails utterly to explain why this simplicity in ratemaking is more important than ensuring that customers do not pay more than actual cost for the capital needed to build the projects.[75]

We understand this to mean that Cooperatives oppose any use of hypothetical capital structures and that the only way to protect customers from overcharging is for the Commission to order a formula rate. However, Cooperatives offer no evidence of actual overcharging to support their opposition to the use of hypothetical capital structures.

50. In adopting Order No. 679, the Commission rejected allegations that the use of hypothetical capital structures for electric transmission companies had resulted in abnormally high equity ratios or over-compensation for the equity holder at the expense of the ratepayer.[76] Although the Commission declined to adopt a general policy on their use, it stated that hypothetical capital structures can be an effective tool to foster transmission investment in appropriate circumstances.[77] On rehearing, the Commission affirmed its earlier finding and noted that it and state commissions have the ability to prevent any regulated company from increasing its debt ratio to a level that unnecessarily exposes wholesale or retail customers to unnecessary risk.[78]

51. The Commission discussed the beneficial use of a hypothetical capital structure in *Trans-Allegheny Interstate Line Co.*[79] where it stated that use of a hypothetical capital

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[75] *Id.* at 17.

[76] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 134.

[77] *Id.* PP 131, 134 (citing, as an example of usefulness for project financing, *Western Area Power Administration*, 99 FERC ¶ 61,306, *reh'g denied*, 100 FERC ¶ 61,331 (2002), *aff'd sub nom. Public Utilities Commission of the State of California v. FERC*, 367 F.3d 925 (D.C. Cir. 2004)).

[78] *Id.* P 93.

[79] *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, at PP 74-76, *reh'g denied*, 121 FERC ¶ 61,009 (2007) (*TRAIL*).

structure could lower debt costs by enabling the transmission developer to vary its financing vehicles to the needs of construction, e.g., timing of expenditures, regulatory developments, and is consistent with Commission precedent.[80]

52. While Cooperatives are correct that a formula might have been a feasible alternative to the proposal before the Commission, no such formula was in the record for Commission consideration.[81] The Commission found that Applicants' requests were consistent with Order No. 679, and therefore just and reasonable.

F. ROE Issues

1. Incentives Order

53. Given the size, scope, costs, benefits, and risks of the Projects, the Commission granted each Project the 150 basis point adder as a project-related ROE incentive. It also granted the 50 basis point adder for participation in an RTO, to be effective on the dates that Applicants become SPP members and place the Projects under SPP's operational control.[82] The Commission denied various other ROE incentive adders that Applicants had requested, but granted the non-ROE incentives of recovery of prudently incurred pre-commercial costs and authorization of 100 percent of CWIP.[83]

54. The Commission found that Applicants' proposed base ROE of 10.8 percent was reasonable. Therefore, the Commission excluded this and zone of reasonableness issues from the hearing that it ordered on Applicants' formula rates and rate protocols.[84]

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[80] *Id.* PP 74-76 (citations omitted). *See also Nevada Hydro Co.*, 122 FERC ¶ 61,272, at P 51 (2008), *reh'g denied*, 133 FERC ¶ 61,144 (2010).

[81] *See Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (under the FPA, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology, or even the most accurate one"); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (a utility is not required to demonstrate that a proposed methodology is more reasonable than an alternative methodology; it need only show that the proposed methodology is just and reasonable).

[82] Incentives Order, 125 FERC ¶ 61,248 at PP 58, 61.

[83] *Id.* PP 59-67.

[84] *Id.* PP 73, 91.

55. The Commission began its discussion of Applicants' proposed base rate ROE by citing several orders stating that the appropriate proxy group for use in calculating ROE using the discounted cash flow method comprises companies from the region in which the utility is located.[85] The Commission explained that use of an established proxy group, such as a proxy group of companies in SPP, Midwest Independent System Operator, Inc.[86] and PJM Interconnection, L.L.C. (SPP-MISO-PJM), allows for an up-front determination of the appropriate ROE, and that it had previously found that the SPP-MISO-PJM region is a reasonable proxy group for utilities in SPP requesting incentive rates.[87]

56. The Commission found that Applicants had insufficiently screened their proxy group. Therefore, the Commission applied additional screens to Applicants' proposed 24-company proxy group to ensure that the proxy group was composed of companies having risks comparable to Tallgrass's and Prairie Wind's risks, and described its use of discounted cash flow analysis.[88] The Commission excluded companies not classified as electric utilities. By using only companies within a corporate credit rating band of one below to one above Applicants' investors, the Commission excluded companies whose corporate credit ratings were not comparable to Applicants' credit ratings. The Commission excluded companies involved in merger activity and companies considered primarily gas companies. The Commission screened out from the proposed proxy group companies with unsustainable growth rates. Lastly, the Commission excluded companies whose low side implied cost of equity was approximately the cost of debt. After performing its own analysis, the Commission concluded that a zone of reasonable returns

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[85] *Id.* P 74 (citing *Atlantic Path 15, LLC*, 122 FERC ¶ 61,135 (2008), *order on reh'g*, 133 FERC ¶ 61,153 (2010) (*Atlantic Path*); *Southern California*, 121 FERC ¶ 61,168; *Bangor Hydro Electric Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265, *clarification granted*, 124 FERC ¶ 61,136 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *reh'g denied*, 102 FERC ¶ 61,143 (2003)).

[86] Effective April 26, 2013, MISO changed its name from "Midwest Independent Transmission System Operator, Inc." to "Midcontinent Independent System Operator, Inc."

[87] Incentives Order, 125 FERC ¶ 61,248 at P 75 (citing *Atlantic Path*, 122 FERC ¶ 61,135 at P 23); *Westar Energy, Inc.*, 122 FERC ¶ 61,268, at P 94 (2008) (*Westar*)).

[88] *Id.* P 76 & n.76.

for Applicants was 7.9 percent to 16.9 percent, with a base median ROE of 10.8 percent, based on a discounted cash flow analysis of the revised proxy group.[89]

2. **Rehearing Request**

57. Cooperatives make four arguments concerning the 10.8 percent ROE determination. First, they argue that because there were disputed issues of material fact concerning the ROE, the Commission should have set these issues for hearing.[90] Cooperatives rely on Order No. 679-A, which states that, in most cases, ROE range of reasonableness determinations would be matters for evidentiary hearings.[91] Cooperatives cite *TRAIL* and *Southern California Edison Co.* as examples of Commission precedent requiring a hearing.[92] Accordingly, Cooperatives contend that, before the Commission departed from its traditional approach of setting a disputed rate for hearing, the Incentives Order should have provided a reasoned basis for the Commission's departure.

58. Cooperatives rely also on *New York Regional Interconnect, Inc.*, where the Commission conditioned the grant of incentive rate treatment on the project developer obtaining state approval of the proposed project and on the state finding that the proposed project will ensure reliability or reduce the cost of congestion.[93] Cooperatives contend that Applicants are in the same situation as was the applicant in *New York Regional*; like that applicant, Applicants have not yet obtained property rights for the route, or siting

[89] *Id*. PP 77-78. The Commission identified the companies in its proxy group at P 78 n.82.

[90] Rehearing Request at 18.

[91] *Id*. at 20 (citing Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 68 (2006) (cross-referenced at 117 FERC ¶ 61,345 at P 68) ("In most cases, an ROE determination occurs in a hearing that considers the justness and reasonableness of the costs of the investment for purposes of setting rates under section 205. In that hearing, the overall range of reasonableness would be established, as well as a determination of where within that range the ROE should be set. If the Commission granted a request for an incentive ROE at the upper end of that range . . ., the hearing would establish where in the upper end the ROE would fall.").

[92] *Id.* at 20-21 (citing *TRAIL*, 119 FERC ¶ 61,219 at P 40; *Southern California Edison Co.*, 122 FERC ¶ 61,187, at P 27 (2008) (*Southern California II*)).

[93] *New York Regional Interconnect, Inc.*, 124 FERC ¶ 61,259, at P 36 (2008) (*New York Regional*).

approval from any of the relevant state regulatory commissions. Moreover, the Applicants have neither customers nor a rate on file. According to Cooperatives, the Projects have not yet been addressed by the SPP regional planning process. Cooperatives ask why the Commission reached different outcomes about a hearing in *New York Regional* and in this proceeding, cases that Cooperatives consider similar.[94]

59. Second, Cooperatives contend that the Commission was arbitrary and capricious and that it denied Cooperatives due process when it summarily determined the proxy group, the range of reasonableness, and the 150 basis-point incentive adder, without first addressing the disputed issues of material fact that Cooperatives and other parties had raised.[95] Cooperatives posit that perhaps the Commission considered Cooperatives' and other parties' protests to be insufficiently detailed or supported by insufficient evidence. Nevertheless, they contend that their protests met the standard for an evidentiary hearing, which is that the inferences to be drawn from the underlying facts contained in such material must be viewed in the light most favorable to the party opposing the application.[96]

60. Third, Cooperatives object that 21 days for entities to intervene and protest the proceedings and to respond to the Applications afforded insufficient opportunity for them or other parties to analyze and respond fully, with expert testimony and exhibits, to the factual, economic, and opinion evidence submitted as part of the Applications.[97] The disputed issues included the claimed reliability benefits, the undetermined effect of the Prairie Wind Project on the delivered cost of power, and overstatement of the actual risks faced by Applicants. According to Cooperatives, these disputed issues of material fact should have precluded the Commission's summary finding of the proper ROE and ROE

[94] Rehearing Request at 23. Applicants also cite *Southwestern Elec. Power Co.*, 125 FERC ¶ 61,389 (2008) as another case where the Commission set ROE provisions for hearing.

[95] Rehearing Request at 24.

[96] *Id.* at 25 (citing *U.S. v. Diebold*, 369 U.S. 654, 655 (1962); *Gen. Elec. Co. v. Joiner*, 522 U.S. 136, 143 (1997)).

[97] *Id.* at 26-27. Cooperatives point out that, in contrast, the Commission gave parties 45 days to file their written responses to the proposed ROE ruling in *Southern California II*. *See Southern California II*, 122 FERC ¶ 61,187 at P 27.

incentive adders and were relevant to the Commission's determination of whether Applicants met the nexus test, under section 219.[98]

61. Last, Cooperatives contend that the Commission's modification and summary approval of Applicants' ROE proposal denied parties an opportunity to respond to the Commission's supplemental ROE evidence. In the underlying proceeding, Cooperatives had objected that Applicants' discounted cash flow model failed to exclude both low-end and high-end cost of equity values, consistent with Commission precedent, and that Applicants' proxy group included entities with extreme returns on equity, ranging from 16 percent up to 26 percent and thus included entities with non-sustainable growth rates.[99] Applicants acknowledge that the Commission partially addressed flaws in Applicants' discounted cash flow model, but contend that the Commission's explanation of its adjustments is summary in nature and unclear as to precisely how the Commission arrived at its proxy group. Cooperatives object to the Commission's supplementation of Tallgrass's and Prairie Wind's evidence without having allowed parties an opportunity to review and respond to this supplemental evidence. According to Cooperatives, due process requires that once the Commission has materially supplemented and amended the Applications, the Commission should have provided notice of the amended Applications and afforded parties an opportunity to respond before issuing a final order.[100]

62. Cooperatives allege that the Commission's action ignored the requirement of section 205 and the Commission's regulations, at 18 C.F.R. § 35.13(e)(3), that Applicants bear the burden of proof. Because the Commission does not permit parties to introduce new evidence at the rehearing stage, Cooperatives state that they are precluded from submitting evidence with their rehearing request to respond to the Commission's modifications of Applicants' ROE transmission incentives.[101]

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[98] Rehearing Request at 27-28.

[99] *Id*. at 28.

[100] *Id.* at 29 (citing *Pub. Serv. Comm'n of Kentucky v. FERC*, 397 F.3d 1004, 1013 (D.C. Cir. 2005) (*Public Service*).

[101] *Id.* at 29-30.

3. Commission Determination

a. Need for Evidentiary Hearing

63. We address first Cooperatives' claim that issues concerning the Projects' reliability benefits, the undetermined nature of the delivered cost of power, and overstatement of Applicants' risks, are disputed issues of material fact that affect determination of the appropriate ROE.[102] We find that these particular issues concern Applicants' request for transmission incentives and whether Applicants have met the eligibility or nexus test for being granted these incentives. We find also that the Incentives Order and our preceding discussion, which found that the transmission incentives were properly granted, have satisfactorily addressed these issues.

64. We address next Cooperatives' argument that Order No. 679 and Commission precedent require the holding of an evidentiary hearing to determine the appropriate ROE. This assertion is incorrect. In Order No. 679, in discussing procedural requirements for obtaining incentive-based rate treatment, the Commission stated, "[T]he Commission does not intend to routinely convene trial-type, evidentiary hearings to review either a comprehensive or single-issue section 205 filing but will attempt to render a decision based on the paper submissions whenever possible."[103]

65. In Order No. 679-A, directly after the paragraph relied upon by Cooperatives,[104] the Commission discussed how hearing procedures for determining ROE can create uncertainty for investors. In Order No. 679-A, the Commission stated that, under traditional ratemaking processes, the rates for a particular project, including the ROE, are determined only *after* an investment decision is made and the facility is constructed. The Commission explained that it would consider requests that set the ROE for a particular project and that include the appropriate support for the ROE. An example of appropriate support would include a discounted cash flow analysis. The Commission added that an applicant seeking an up-front ROE determination would have to meet the required nexus requirement, such as by showing that an up-front ROE determination is important for its investment decision.[105] On further rehearing, the Commission stated that if some of the incentives in the total package of incentives sought to reduce the risks of the project, that

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[102] *Id.* at 27.

[103] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 79.

[104] *Supra* P 57 & n.92.

[105] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at PP 69-70.

fact will be taken into account in any request for an enhanced ROE.[106] Clearly, in Order No. 679-A, the Commission acknowledged that an up-front determination of the project's ROE can hasten transmission project construction, and that an evidentiary hearing is not always needed. Such was the case for the Projects.

66. While Commission precedent includes some transmission incentive cases where the Commission required an evidentiary hearing on ROE issues, it also includes cases where the Commission was able to address ROE issues without an evidentiary hearing on the basis of the record in the proceeding record and other documents.[107] Courts have stated, "A trial-type hearing is unnecessary where there are no material facts in dispute;" and "mere allegations of disputed facts are insufficient to mandate a hearing; petitioners must make an adequate proffer of evidence to support them."[108]

67. We turn to Cooperatives' reliance on *TRAIL* as stating that Commission precedent generally requires an evidentiary hearing. In *TRAIL*, the Commission was dissatisfied with the composition of the proxy group that the applicant had used to establish its base ROE.[109] The Commission cited its general policy, in place at that time, that a proxy group must be comprised of transmission owners with a direct link to the same RTO or Independent System Operator in which the applicant is located.[110] The Commission found that the applicant had not shown that its proposal to include in its proxy group

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[106] Order No. 679, 119 FERC ¶ 61,062 at P 11.

[107] Proceedings where the Commission did not establish hearing procedures on ROE issues, as protestors had requested, include: *Central Maine II*, 125 FERC ¶ 61,182 at PP 93-94; *Central Maine I*, 125 FERC ¶ 61,079 at PP 74-76. In a 2010 case about transmission incentives, the Commission expounded on the need for an evidentiary hearing, stating, "[E]ven where there are disputed issues, the Commission need not conduct a hearing if they may be adequately resolved on the written record." *Pioneer Transmission*, 130 FERC ¶ 61,044 at P 35.

[108] *See Northeast Utilities Serv. Co.*, 125 FERC ¶ 61,183, at P 54, (2008), *reh'g denied*, 135 FERC ¶ 61,270 (2011) (citing *Pa. Pub. Util. Comm'n v. FERC*, 881 F.2d 1123, 1126 (D.C. Cir. 1989); *Woolen Mill Assoc. v. FERC*, 917 F.2d 589, 592 (D.C. Cir. 1990)).

[109] *TRAIL*, 119 FERC ¶ 61,219 at P 8 & n.12.

[110] We note that the Commission has since changed its approach to determining the ROE for public utilities. *See Martha Coakley, Massachusetts Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234, at P 96 (2014).

companies with no direct link to the pertinent RTO was just and reasonable. Thus, the Commission set for hearing the applicant's proposed ROE, including the composition of its proxy group. Because an earlier order had established only that the ROE would be set in the high end of the zone of reasonableness, the Commission included, as hearing issues, the overall range of reasonableness as well as where, in the upper end of the range, the ROE would fall.[111] The situation in *TRAIL* differs from the situation here where the Commission was able to correct the composition of Applicants' proposed proxy group of companies in the SPP-MISO-PJM region and to make an up-front determination of the appropriate base ROE.[112] As observed in the Incentives Order, the Commission had previously found that the companies in the combined SPP-MISO-PJM region make a reasonable proxy group for applicants in SPP requesting incentive rates.[113] We deny rehearing on the claim that Commission precedent necessarily requires an evidentiary hearing to address disputed ROE issues.

b. <u>Proxy Group Modification</u>

68. We address Cooperatives' concern that the Commission's explanation, in the Incentives Order, of its modification of the proxy group was summary in nature and unclear. In so doing, we clarify the Commission's adjustments, made in the Incentives Order, in answer to the issues raised in Cooperatives' October 24, 2008 protest to the Prairie Wind Application[114] and Cooperatives' October 29, 2008 protest to the Tallgrass Application.[115]

69. Cooperatives protested that Prairie Wind's proxy group included entities with extraordinarily high return on equity values for 2008-2013 in the growth calculations. It named three companies, DPL, Inc. (DPL), PPL Corp. (PPL), and Exelon Corp. (Exelon), as showing returns on equity for 2008-2013 that are extreme ranging from 16 percent up

[111] *Trail*, 119 FERC ¶ 61,219 at P 40.

[112] Incentives Order, 125 FERC ¶ 61,248 at PP 74-78.

[113] *Id.* P 75 (citing *Westar*, 122 FERC ¶ 61,268 at P 94 (citing, in turn, to orders requiring seams agreements for these highly interconnected grid regions to coordinate reliability practices and market interface practices)).

[114] Cooperatives October 24, 2008 Protest to Prairie Wind Application at 29-30 (Prairie Wind Protest).

[115] Cooperatives October 29, 2008 Protest to Tallgrass Application at 30-31 (Tallgrass Protest).

to 26 percent. According to Cooperatives, such growth rates are not sustainable; therefore, consistent with Commission precedent, such entities should be excluded from the proxy group used in the discounted cash flow analysis.[116]

70. We clarify that, when the Commission modified the proxy group, it excluded Exelon from the discounted cash flow analysis due to merger activity in the preceding six months, caused by Exelon's offer, on October 18, 2008, to acquire all of the outstanding stock of NRG Energy, Inc. in an all-stock transaction. The Commission also excluded PPL on the grounds that its I/B/E/S[117] growth rate was 17 percent, which exceeds levels previously determined by the Commission to be sustainable.[118] The Commission did not exclude DPL because, despite its high ROE values, the associated growth rate was still below levels previously determined to be unsustainable.

c. <u>Sufficient Time to Comment Meaningfully</u>

71. We disagree that the Commission gave Cooperatives insufficient time to respond to the Applications. The 21 days that the Commission allowed for interventions and comments in the notice announcing that the Application had been filed is the standard comment period that the Commission gives FPA section 205 rate filings. No entity, including Cooperatives, requested a time extension. Moreover, the rehearing stage of

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[116] Prairie Wind Protest at 30.

[117] The Institute Brokers' Estimate System gathers and compiles the different estimates made by stock analysts on the future earnings for the majority of U.S. publicly traded companies. It is a central location whereby investors are able to research the different analyst estimates for any given stock without necessarily searching for each individual analyst.

[118] In *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 100 (2008), *order on reh'g*, 133 FERC ¶ 61,152 (2010) (*PATH*), and *ISO New England Inc.*, 109 FERC ¶ 61,147, at P 205 (2004), the Commission stated that 13.3 percent growth rate is not a sustainable growth rate over time and therefore does not meet the threshold test of economic logic. The Commission did not exclude PPL from the proxy group in *PATH* because PPL Corp.'s growth rates were less than 13.3 percent, based on September 2007 data.

these proceedings is too late to raise this issue because the Commission will not entertain new issues on rehearing.[119]

d. <u>Opportunity to Respond to Commission Modification</u>

72. Cooperatives' reliance on *Public Service*[120] to support their position that they have been denied due process of law is misplaced. In *Public Service*, the court found that the Commission violated the parties' due process rights because the Commission, having initially determined that it would not grant an incentive ROE adder, at the end of the proceeding granted the incentive ROE adder, and thus failed to place the parties on notice at the outset that, post-hearing, its order might grant the incentive ROE adder.[121] The court explained that, while the Commission considered the petitioners' arguments regarding the incentive ROE adder on rehearing, the Commission did not allow them to present evidence at hearing on the relevant factual issue, i.e., the need for, or appropriate size of, the incentive ROE adder.[122] In contrast, here the parties had notice that the discounted cash flow model and the record evidence on which it was based would be used to determine the Applicants' ROE. Further, Cooperatives had an opportunity to present evidence and argument on that issue, they availed themselves of that opportunity both in their protests and rehearing requests,[123] and the Commission has considered Cooperatives' arguments on this issue.[124] Therefore, the Commission rejects Cooperatives' assertion that they were denied due process.

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[119] *Allegheny Energy Supply Company*, LLC, 122 FERC ¶ 61,104 (2008). *See also Calpine Oneta Power, L.P. v. American Elec. Power Serv. Corp.*, 114 FERC ¶ 61,030, at P 7 (2006).

[120] *Supra* note 100.

[121] *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d at 1012.

[122] *Id.*

[123] *See* Prairie Wind Protest at 29-30; Tallgrass Protest 31; Rehearing Request at 28-30.

[124] *Supra* PP 68-70.

<u>The Commission orders</u>:

The rehearing request filed by Cooperatives is hereby denied, as discussed in the body of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.