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The Facilitation Of Nonincumbent Transmission Projects

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On April 13, 2010, the Federal Energy Regulatory Commission ruled that the PJM Interconnection LLC (PJM) Open Access Transmission Tariff (OATT) does not preclude PJM from designating an entity other than an incumbent transmission owner, as the entity to build a new transmission project within PJM if the proposed project is included in PJM's Regional Transmission Expansion Plan (RTEP) as a baseline reliability project or economic project.

The Commission further ruled that the PJM OATT does not prevent a nonincumbent transmission owner from seeking cost-based rate recovery if its project is included in the RTEP and satisfies the same reliability and/or economic requirements set forth for other transmission owner cost-based projects in the PJM OATT.

FERC concluded that treating non-incumbent transmission owners the same as incumbent transmission owners for these purposes would provide substantial certainty to entities seeking to develop baseline reliability or economic transmission projects within PJM that are not already transmission owners in PJM and do not want to take on the risks associated with owning merchant transmission facilities.

The FERC's ruling came in response to a Petition for Declaratory Order filed by Primary Power, LLC (Primary Power) requesting approval of certain transmission rate incentives, including a request for a base return on equity (ROE) and ROE "adders," for its proposed Grid Plus Transmission System (Grid Plus) under the Federal Power Act (FPA) sections 205 and 219 and Order No. 679.

Primary Power sought assurance that it is eligible to propose and be designated to build a project under PJM's RTEP, and will thereby be eligible for cost-based rates even though it is not an incumbent transmission owner. To implement such assurances, Primary Power unilaterally filed an interconnection service agreement for FERC approval.

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As proposed, Grid Plus is comprised of four 500 MVar (500+/-100-) Static Var Compensators (SVC) with a combined cost of \$200 million. Specifically, the SVC facilities consist of 500+ MVar capacitive, and 100- or more inductive, depending on location. Two SVCs are planned for Jacks Mountain in Mifflin County, Pennsylvania, one SVC is planned for the Juniata substation in Perry County, Pennsylvania, and one SVC is planned on the Meadowbrook 500 kV line in Hardy County, West Virginia. These types of facilities would not easily lend themselves to the merchant transmission facility model generally or an “open season” process more specifically. Once construction of Grid Plus is complete, Primary Power intends to turn operational control of Grid Plus over to PJM and become a Participating Transmission Owner in PJM. Primary Power estimates that it will take two years to complete the project, after receipt of approval to proceed. Primary Power intends to begin construction on the first SVC in early 2010, to be operational in 2012.

Primary Power requested approval of the following incentive-based rate treatments, contingent on Grid Plus’ approval through the PJM RTEP:

- Approval of a regulatory asset for start-up and development costs to accrue carrying charges (*i.e.*, an overall rate of return). Primary Power proposed to expense and to amortize the regulatory asset over five years in rates, as each SVC facility enters service. Primary Power requested the approval to accrue carrying charges on these costs 61 days from the date of its filing until the time that the regulatory asset is fully amortized.
- Recovery of prudently incurred costs in the event any of the SVCs are abandoned for reasons beyond Primary Power’s control.
- Hypothetical capital structure of 40 percent debt and 60 percent equity ratio until the first facility’s commercial operation date; thereafter Primary Power will apply its actual capital structure.
- A stated base ROE of 12.75 percent, with the eligibility to seek increases to the base ROE in future rate cases: (1) a 50 basis point ROE incentive adder for RTO participation, (2) 100 basis point ROE adder for transco status and (3) 150 basis point ROE adder for new transmission investment, for a combined total adder of 300 basis points.

The FERC granted in part and denied in part Primary Power’s request. FERC held that the PJM OATT permits, but does not require, PJM to designate Primary Power, an entity other than an incumbent transmission owner, as the entity to build Grid Plus if the project is included in the RTEP as a baseline reliability project or economic project. FERC found that the PJM Transmission Owners do not have a right of first refusal respecting projects proposed by other entities. Both PJM and the PJM Transmission Owners argued in this proceeding that the right of first refusal applied here. FERC stressed that PJM must designate projects under the relevant tariff provisions in a not unduly discriminatory manner, whether sponsored by transmission owners or others, and should handle the study of Primary Power’s application no differently than that of any other application proposing to build a project, be it an existing transmission owner or another entity, and would need to justify any denial of a project sponsor’s right to construct the project and receive the economic benefit from the project. Although FERC rejected as premature Primary Power’s request for an effective date for cost-based rate treatment, FERC held that the PJM OATT does not prevent Primary Power from seeking cost-based rate recovery if its project is included in the RTEP and satisfies the same reliability and/or economic

This article is intended only as a general discussion of these issues. It is not considered to be legal advice. We would be pleased to provide additional details or advice about specific situations. For additional information on this important topic, please feel free to call upon your Dewey & LeBoeuf relationship partner.

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requirements set forth for other transmission owner cost-based projects in the PJM RTEP and Tariff. FERC, however, declined to approve the proposed interconnection agreement that was unilaterally filed by Primary Power but indicated that there is ample time for Primary Power to negotiate and have PJM file an interconnection agreement.

These same issues were also before the FERC in another proceeding. Central Transmission, LLC (“Central Transmission”) filed a complaint with the FERC on March 25, 2010, in Docket No. EL10-52, seeking a Commission finding that the PJM Operating Agreement and PJM OATT are unjust and unreasonable and unduly discriminatory insofar as certain provisions of the OATT and Operating Agreement could prevent PJM from designating Central Transmission to construct and own its proposed transmission project, the LaSalle Project, under the same cost recovery provisions available to the incumbent PJM transmission owners. In light of FERC’s ruling on Primary Power’s petition, Central Transmission’s complaint appears moot as the Commission has found that the PJM OATT already allows PJM to designate nonincumbent transmission owners to construct and own proposed transmission projects and to obtain cost-based rates for such projects.

With respect to rate incentives, subject to the inclusion of the project in PJM’s RTEP, FERC granted Primary Power (i) authorization to establish the regulatory asset; (ii) cost recovery of prudently incurred costs should the project be abandoned for reasons outside of Primary Power’s control (to become effective once the project is included in the RTEP); (iii) a 50 basis point ROE incentive adder for RTO participation; (iv) a 100 point ROE incentive adder provided for transco formation; (v) a 50 basis point ROE incentive adder (reduced from the 150 points requested) to reflect the overall siting, permitting, regulatory, technical and financing risks of the project; (vi) a 50 basis point adder for non-routine investment (applicants did not request an adder for this reason) and (vii) the requested 60/40 hypothetical capital structure. There is an inconsistency within the order in that FERC summarized the ROE adders as totaling 200 basis points rather than the 250 basis points which the individual adders would appear to total. In earlier orders regarding transmission rate incentives, FERC did not typically break out separate adders for siting, permitting, regulatory, technical and financing risks of the project; on the one hand, and nonroutine investment on the other hand. The granularity with which FERC described the ROE adders in this proceeding may reflect the more conservative approach that Democratic Commissioners at FERC have taken in the past with respect to granting ROE adders. FERC did not establish a base ROE of 12.75 percent as requested, so FERC did not make a decision on the total ROE Primary Power will receive for the project and only ruled on the ROE adder. FERC deferred consideration of a base ROE until after RTEP approval for the project. This refusal likely reflects a concern that the base ROE may become “stale” by the time the project is approved in the RTEP process.