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Addendum StartPage: 0

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PROCEEDING RELATING TO ERCOT PLANNING AND SYSTEM COSTS ASSOCIATED WITH RENEWABLE RESOURCES AND NEW LARGE DC TIES	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

INITIAL COMMENTS OF CALPINE CORPORATION

Calpine Corporation ("Calpine") appreciates the opportunity to file initial comments in this proceeding. Calpine supports the Commission's interest in developing information about the role and treatment of renewable resources in three distinct areas that are critical to system reliability: transmission planning, transmission investment and ancillary services. A broad theme emerges from the questions, which openly asks whether cost-causation theory should be applied to a particular technology; in this case, renewable resources. Calpine does not take a position on the questions that specifically address cost-causation based on generation technology. However, the Commission and market participants will be well-served by understanding the drivers and their impacts on system transmission planning, transmission investment and ancillary services because they result in real costs that have to be accounted for and recovered in the market.

The Commission also included a list of DC Tie questions grouped into four topics: transmission planning, transmission investment, ancillary services and registration. Calpine believes this review is timely and encourages the Commission to consider the impact of prospective DC Tie projects on the ERCOT transmission system and where appropriate, apply cost-causation principles to directly assign the cost of necessary upgrades.

Renewable Resources

Transmission Planning

1. **Is the production cost savings test required by Substantive Rule 25.101(b)(3)(A)(i) generally appropriate for analyzing the benefits of transmission projects, especially projects to address transmission limitations and voltage stability mitigation that will be needed to address a system heavily weighted with wind generation with a production cost of zero?**

   Please see the response to question 2, below.

, 21

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2. **For purposes of this section, assume that transmission projects are long-lived assets and the capital investment decisions of generators are at least somewhat influenced by transmission planning policy.**
    a. **Is it appropriate for any production cost savings analysis to focus on short-run marginal production costs (where installed capacity is assumed to be fixed)?**
    b. **If not, should long-run marginal production costs (wherein capital investment costs are assumed to be variable) or other considerations be applied to any production cost savings analysis, especially with respect to renewable resources?**

    In Calpine's experience generation acquisition and development decisions for ERCOT – whether green-field projects or uprates – are influenced by transmission planning policy, but more importantly the planned transmission projects that are a result of those policies. Calpine believes that an appropriate cost-benefit analysis of a transmission project should consider all costs and benefits over the expected life of the project, including production cost savings and the capital costs of additional resources that would be developed (or avoided) as the result of additional transmission. For example, a transmission project may enable the development of additional resources in an area that is remote from load and reduce the need for resources close to load. Ultimately, the capital costs associated with the new, more distant resources are borne by customers through either sufficiently high energy prices or bilateral contract payments and hence should be included in cost-benefit analysis of transmission. A focus only on short-run marginal production costs could result in a bias towards building transmission and developing remote resources. Calpine does not offer a specific proposal, but encourages the Commission to consider engaging an independent, third party to conduct a study and offer a recommendation, to supplement the production cost savings methodology by including long-term or capital costs.

    c. **What, if any, production costs should be assigned to renewable resources?**

    Calpine does not take a position on assigning specific production cost value for renewable resources. However, as discussed below, estimates of ancillary services costs that are attributable to renewables is one focus of the Future Ancillary Services Team ("FAST").

Investment in Transmission System

1. **To the extent that renewable resources impact grid stability, as the transmission system grows how should the cost of maintaining grid stability be allocated?**

    No comment at this time.

2. **Should renewable resources help fund further investment in the transmission system? What mechanisms and methodologies should be used to determine and assign those costs?**

   No comment at this time.

   a. **Can the Commission implement these mechanisms and methodologies under existing law?**

      No comment at this time.

Market

1. **What ancillary services costs are incurred specifically due to the employment of renewable resources in the ERCOT generation mix?**
   a. **Are these costs disproportionately large as compared to other causes? Explain.**
   b. **How can incremental increases in ancillary services costs be identified and quantified as the installed capacity of variable renewable resources increases?**

   Calpine supports the work of ERCOT staff to analyze the future need for ancillary services that are being driven by retirement of older gas-steam and coal units, which are being replaced in part with more renewables. This technology transition is leading to less base-load capability and more intermediate and peaking capability. Calpine supports the work of FAST to address this developing generation mix and determine if any specific service (like CAISO's "ramping" service) might become necessary. ERCOT does not have any Ancillary Services that are directly tied to renewable resources – largely because the suite of ancillary services generally is agnostic as to technology – which makes it more difficult to specifically identify such costs. In our view, questions 1, 1.a. and 1.b. are best answered by ERCOT, the Independent Market Monitor ("IMM") or at the direction of the Commission, through a study by an independent, third party. In summary, Calpine believes the Commission should understand the drivers for the necessary ancillary services and their costs, regardless of the reason, including technology-specific drivers.

   c. **How should any assignment or allocation of ancillary services costs be properly designed to reflect any costs incurred due to the nature of renewable resources?**

      No comment at this time.

2. **What effect has the increased deployment of renewable resources had on market prices in the ERCOT system?**

   This question is best answered by ERCOT, the IMM or at the direction of the Commission, through a study by an independent, third party.

3. **What effect, if any has increased the deployment of renewable resources had on Peaker Net Margin as used in Substantive Rule 25.505 (g)?**

This question is best answered by ERCOT, the IMM or at the direction of the Commission, a study by an independent, third party.

DC TIES

Transmission Planning

1. **How should the uncertainty of whether DC Ties will be exporting or importing be addressed in transmission planning?**

   The holder/s of firm transmission rights on the opposite side of the merchant DC Tie in question should be required to report to ERCOT on a periodic basis and provide the protected contract information that would allow ERCOT to properly account for DC Tie flows out of ERCOT in their short term and Long Term System Assessment transmission planning efforts.

   To the extent that DC Tie external firm transmission rights do not cover the entire period of the subject planning horizon in question, ERCOT should extend the rights in their resource input assumption set to match the tenor of the study.

   From a strictly resource planning standpoint, the Capacity, Demand and Reserve Report methodology adopted to account for DC Tie flows into ERCOT , the Total Capacity Estimate also should be appropriate for transmission planning. See ERCOT Protocols at 3.2.6.2.2. The methodology uses the average DC Tie capacity imported into ERCOT during the highest 20 peak load hours for each year of the preceding three-year period. This average value could be used to cover not only the short term transmission planning function, but also for the duration of a longer transmission planning study horizon.

2. **What relationship exists between ownership of transmission equipment (including converter stations) and cost responsibility for transmission upgrades? What relationship, if any, should exist?**

   No comment at this time.

3. **What potential grid stability problems might occur with the construction of additional DC Ties? If such grid stability problems could occur, what mitigation measures should be undertaken? Estimate the cost of such mitigation.**

   Additional DC Tie imports and exports can act respectively as resource contingencies or load rejections when the Tie in question fails or is cut due to external issues over which ERCOT has no control. New Merchant DC Ties should be treated similar to generators interconnecting in ERCOT. If a merchant interconnection requires additional system upgrades in order to mitigate identified system stability conditions created by their interconnection, then they should be required to fund the upgrades. In the event their interconnection causes the output of any incumbent generator to become impaired, on a strict cost-causation basis, they should have the responsibility of funding the necessary upgrades to make that incumbent generator whole.

4. **Has a ceiling on the number or size of DC Tie installations been identified below which the existing ERCOT grid can accommodate DC Tie installations without major upgrades by transmission service providers (TSPs) and without changes in ERCOT operational practices?**

   Calpine does not have a substantive response, but notes that this is a question best answered by ERCOT's Planning Department and/or the Transmission Operators ("TO") and Transmission and Distribution Service Providers ("TDSP"), based on their system assessment studies.

5. **Under current ERCOT Protocols, DC Ties are not currently dispatchable and therefore the load on DC Ties cannot be changed by Security Constrained Economic Dispatch (SCED). Should the ERCOT Protocols be rewritten to allow DC Ties to be dispatchable?**

   Yes. Sub-hourly dispatch of future merchant DC Ties would be desirable because it would allow the owner to optimize the use of the Tie. Although, making a future merchant DC Tie dispatchable might lead to inadvertent energy accumulation unless symmetry is achieved with NERC E-Tagging on the other side of the Tie. Without changes on both sides of the Tie to the treatment of the resulting energy flows the owner of the Tie rights would have to bear any schedule mismatch risk.

Investment in Transmission System

1. **To what extent, if at all, should a DC Tie owner be required to bear cost responsibility for transmission upgrades by TSPs that are required to accommodate power flows over the DC Tie?**

   Prospectively, merchant DC Tie projects should be considered a commercial venture and the owners, in keeping with the principles of cost-causation, should be responsible for any and all system upgrades needed to make their project viable. Additionally, the type and use of their transmission elements to be used by a new Merchant DC Tie to go commercial should be closely scrutinized by both ERCOT's Planning Department and Commission Staff as well as any potentially impacted existing resources to prevent unintended design consequences that would inadvertently allow the commercial risks of a DC Tie to harm existing resources.

2. **The current ERCOT Most Severe Single Contingency (MSSC) is at about 1375 MW. If DC Ties greater than 1375 MW were installed, it is expected that the ERCOT MSSC would likely increase. Assuming this happens and that this increase would require a larger operating Responsive Reserve Service (RSS), who should pay for the increased costs of the RRS? How should increased costs be recovered?**

   The answer to MSSC cost allocation questions is dependent on two separate views of who the beneficiaries might be as a result of a new Merchant DC Ties.

   First, if you assume that the increased commercial activity from a new DC Tie will create additional value in the system then you have to assume that the ultimate

5

beneficiary of that value would be the consumers. After all, the improvements in the supply chain ultimately trickle down to the consumer side of the market in the form of lower energy costs from increased efficiency. Under this view any incremental costs in Responsive Reserves ("RRS") to protect against the loss of incoming energy on the DC Tie – presumably bringing less expensive energy to consumers on the receiving system/ERCOT – should be assessed just as the current cost for RRS. Loads can either buy coverage for it in the Ancillary Market or self-provide it through bilateral contracting.

A second view that might be adopted would include the recognition that the compact between the supply side of the market and the demand side only anticipated that the MSSC only would be assigned based on the largest, single credible contingency of 1,375 MWs (South Texas Project #2) in order to cover the loss of the system's largest thermal unit in order to comply the with the then NERC Policy #1, Disturbance Control Standard (DCS). Further, any incremental Contingency Reserves made necessary by a new Merchant DC Tie should pay the incremental cost of RRS. Thus, in keeping with the principle of NERC Policy #1, captured in NERC Reliability Standard BAL-002-0, incremental contingency reserves in the form of RRS would not be impacted since the DCS standard only applies to supply (DC Tie flows into ERCOT) and not demand (DC Tie flows out of ERCOT).

Market

1. **If DC Tie owners are required to bear some portion of the costs of transmission system investments to accommodate power flows over the DC Tie, what mechanisms and methodologies should be used to determine and assign those costs? Can the Commission implement these mechanisms and methodologies under existing law?**

   Strict cost-causation principles should apply and the mechanism used should be very close to methodology that is currently used to fund generation interconnection system upgrades; except that the payments would not be returned to the Merchant DC Tie owner/operator.

Registration

1. **Should in-state DC Ties owners (who are not public utilities/transmission service providers) be required to register with the PUC or ERCOT? Explain why or why not.**

   Yes, they should be required to register with the Commission. A new category of Merchant DC Tie Operator should be created, which recognizes the reality that a DC Tie can represent an inter-regional/inter-zonal load one hour and can represent a resource in the next. In both instances the operation of the DC Tie, irrespective of the fact that both terminals would be within ERCOT, can have an impact on system economics and security. Additionally, other market participants would need to carry out business with the Merchant DC Tie owner and to the extent ERCOT's customer accounting and registration systems require entity roles be assigned to all market participants these new entities would seem to need to be registered with ERCOT at a minimum. Finally, given the owner's return on investment will depend on ERCOT's calculation of the system 4-Coincident Peak values, it is imperative that the owner register with ERCOT.

2. **Does a TSP in ERCOT have an obligation to serve a merchant DC Tie under federal or state law?**

   No comment at this time.

3. **Does Public Utility Regulatory Act enable the Commission to regulate merchant DC Ties and the provision of transmission service to those ties?**

   No comment at this time.

4. **How should the Commission regulate merchant DC Ties and the provision of transmission service to those ties?**

   A simplistic view would be that since a Merchant DC Tie can function on the supply side of the market as a resource node then the Commission should regulate the Tie with the concept in mind that it should have the same rights and privileges as an interconnected generator. A not incongruent aspect of that treatment would be that just as a disconnected generation station taking system power for the auxiliary powering of systems, the Merchant DC Tie should be treated as a load when its energy is leaving the ERCOT system. The same load obligations for ancillary services and back-up energy provision should be assigned to the Merchant DC Tie in order to fairly assess its impacts on the entire system's needs and to not overly burden the existing system load serving entities.

Respectfully Submitted,

CALPINE CORPORATION

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