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| ERCOT PLANNING AND SYSTEM COSTS ASSOCIATED WITH RENEWABLE RESOURCES AND LARGE DC TIES | §<br>§<br>§ | BEFORE THE<br>PUBLIC UTILITY COMMISSION<br>OF TEXAS |

# TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO REQUEST FOR COMMENTS

## I. INTRODUCTION

Texas Industrial Energy Consumers (TIEC) submits these comments in response to the request for comments issued on August 14, 2014. The Commission's questions raise a broad range of important, far-reaching policy issues. TIEC's responses to these questions are preliminary in nature and TIEC reserves the right to supplement these comments as appropriate. TIEC plans to participate in the workshop on these issues at the end of October.

## II. RESPONSE TO COMMISSION QUESTIONS ON RENEWABLE GENERATION

**Transmission Planning**

- ***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?***

Broadly stated, a production cost savings test will designate a transmission project as economic if it would allow generation resources with a lower production cost to displace generation resources with a higher production costs to a point where the overall reduction in production costs exceeds the costs of the project.[1] TIEC has long viewed this type of transmission test as a flawed and incomplete approach to economic transmission planning. This is because a production cost savings test does not actually measure the savings that consumers would receive from a project in the form of reduced prices. Customers pay prices that are based on Locational Marginal Prices (LMPs)—not each generator's production cost, which only has a

[1] The test described by P.U.C. Subst. R. 25.101(b)(3)(a)(i) requires the annual savings to offset the first year revenue requirement of the project.



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loose relationship with LMPs. When "zero production cost" resources factor into the modeling, a transmission planning test that measures the LMP-based savings to consumers will tend to justify ***less*** transmission than a production cost savings test because these resources are almost never marginal. For example, in the case of wind generation, transmission to alleviate constraints will often be considered economic under a production cost savings test because wind energy looks "free" in that type of model, when in reality the transmission is not cost-justified. An LMP-based test, in contrast, recognizes that wind generation will still be paid the cost of the marginal unit, so increasing wind output only impacts the prices customers pay to the extent that it reduces LMPs, which will generally be ***much less*** than the extent to which it impacts overall production costs. As a result, far fewer projects to maximize wind output would be considered economic under an LMP-based test as compared to a test that measures the production cost savings against the project cost. For these reasons, TIEC recommends that the Commission consider adopting an LMP-based economic model for transmission development.

- ***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.***[2]

  *i.* ***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)?***

  *ii.* ***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?***

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

TIEC is unsure as to the meaning of the questions being asked under this heading. As a general matter, it would not be appropriate to include any capital investment costs in any transmission planning analysis. Consistent with the LMP-based test set forth above, the capital costs of any generation investment are not relevant in establishing LMPs, which are determined by bids in the competitive energy market. Again, the LMP-based test appropriately measures the

[2] As TIEC has noted in past comments, while TIEC agrees that generation investment decisions can be influenced by transmission planning policy, this influence is generally in favor of transmission planning that increases the overall efficiency of the market and not in relation to "load pockets," where any pricing advantage is eroded by the development of any generation within the constrained area.

impact of "zero production cost" resources in transmission planning, which largely eliminates the bias that a production cost method creates for these resources. The Commission should avoid attempting to reverse-engineer transmission planning results for or against any particular resource. Instead, the Commission should properly focus on the benefit to customers and the overall efficiency of the electricity market in determining which transmission projects to construct.

**Investment in Transmission System**

- ***To the extent that renewable resources impact grid stability, as the transmission system grows how should the cost of maintaining grid stability be allocated?***
- ***Should renewable resources help fund further investment in the transmission system? What mechanisms and methodologies should be used to determine and assign those costs?***
    - i. ***Can the Commission implement these mechanisms and methodologies under existing law?***

There is nothing in PURA requiring all transmission costs to be allocated to loads. PURA § 35.004 requires that wholesale transmission services must be priced on a postage-stamp basis, which has traditionally meant that all ERCOT transmission utilities' costs are combined and service charges are then calculated based on the total combined demand. This requirement does not speak to what transmission investment must be included as a "cost" in the rates of an ERCOT transmission utility. If the Commission required certain market participants to fund a portion of transmission investment, that portion of the investment would simply be excluded from the "costs" subject to postage stamp pricing. Just as when the Commission originally decided to put all generation interconnection costs from the step-up transformer (high-side) into transmission rates, the Commission has flexibility to determine what transmission costs should be paid by loads versus other market participants.

TIEC has been a strong supporter of allocating costs based on the principle of cost-causation, which creates the proper incentives to reduce costs and to make efficient decisions in both the market context and in a regulated context. Given this, TIEC believes it would be appropriate from a cost-causation standpoint for the Commission to consider allocating some transmission costs to generation resources. However, under existing law it may not be possible to differentially allocation costs to different types of resources. PURA § 35.004(b) requires the

Commission to ensure non-discriminatory access to wholesale transmission service, and § 39.151(a)(1) requires ERCOT to "ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms." These provisions could be read to bar differential treatment.

Having said that, TIEC previously developed and submitted a proposal whereby all resources would be treated equally with regard to interconnection costs, while at the same time recognizing that different entities may be causing different levels of costs on the system. This proposal involved developing an average per MW interconnection cost allowance, based on historical numbers, and then making this allowance available equally to all resources seeking interconnection. This approach will incentivize siting discipline in generators, so that consumers will not be asked to fund costly transmission to support remotely-sited resources. Many of the reliability issues associated with building generation in areas that are far removed from load centers would also be reduced under this approach, as it would become less economic to site generation in remote, low-load areas. As required by PURA, this approach would also be non-discriminatory because the same allowance would be given to all interconnecting generators and each generator could then make decisions about what additional costs are worth the investment on a case-by-case basis. This approach would likely be preferable to a system where the Commission attempts to "assign" additional transmission costs to specific resource types based on operational or other characteristics.

To the extent this question specifically relates to the pending issues surrounding the costs of mitigating or protecting against Subsynchronous Oscillation (SSO) risk, TIEC refers the Commission to its previous comments in Project No. 42631.

**Market**

- ***What ancillary services costs are incurred specifically due to the employment of renewable resources in the ERCOT generation mix?***

  i. ***Are these costs disproportionately large as compared to other causes? Explain.***

  ii. ***How can incremental increases in ancillary services costs be identified and quantified as the installed capacity of variable renewable resources increase?***

  iii. ***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?***

Wind generation has been identified as significantly contributing to the need for both Non-Spinning Reserve Service (NSRS) and Regulation Service (Regulation). ERCOT and the stakeholders annually review the methodology for determining the amounts of each ancillary service that will be procured. ERCOT's most recent "Methodologies for Determining Ancillary Service Requirements" document was approved by the Board last December. In that document, ERCOT explained that there is a linear relationship between installed wind capacity and the need for additional Regulation,[3] and requested that the Board approve the increased Regulation procurement to account for additional installed wind capacity.[4] While some level of Regulation is always needed to address frequency changes caused by load variability, incremental Regulation needs are also caused by additional installed wind capacity.

Currently, NSRS is also procured based in part on projected wind output. The 2008 GE report to ERCOT evaluating the impact of wind on ancillary service requirements indicated that wind generation should be treated as "negative load" in determining ancillary service requirements, and referred to the system load minus wind generation as "net load."[5] Today, ERCOT's determines how much NSRS to buy by identifying the capacity needed to cover the 95$^{th}$ percentile of uncertainty observed in the Net Load forecast, minus 500 MW of Responsive Reserve Service (RRS) and the average amount of Regulation Up procured, which can also be used to address this forecast uncertainty. Therefore, NSRS is procured to address the combined volatility of load and wind output, or "Net Load" volatility.

TIEC notes that ERCOT is currently reexamining its suite of ancillary services through the Future Ancillary Services Team (FAST) efforts. It is unclear whether any changes proposed through the FAST process will be adopted and if so, when they would go into effect. ERCOT is considering a new ancillary service known as "Synchronous Inertial Response," which would provide system inertia. This ancillary service would be designed to address the lack of system inertia that allegedly can result from high levels of renewable resources, which do not have a heavy "rotating mass" that provides inertia like a thermal generation turbine. There would

[3] http://www.ercot.com/content/meetings/board/keydocs/2013/1210/8_Proposed_Changes_for_2014_Methodology_for_Det_Minimum_Anci.pdf.

[4] Regulation Service consists of resources that can be dispatched up or down by ERCOT to address changes in ERCOT System frequency.

[5] *See* http://www.uwig.org/attchb-ercot_a-s_study_final_report.pdf.

appear to be a strong correlation between the need to develop and procure this service and renewable penetration.

The amount and types of ancillary services that are caused by renewable resources would likely need to be studied further if the Commission seeks to revisit the current approach of allocating these costs to loads. As discussed above, TIEC prefers allocating costs based on cost-causation, but observes that determining what portion of ancillary services are attributable to various market entities with any level of accuracy may be challenging. While it is unclear whether any changes will be adopted in relation to the ongoing FAST efforts and "system inertia" discussions, this creates some uncertainty as to the specific services ERCOT will be procuring in the future. If the Commission requests a new study similar to the 2008 GE study, the Commission should be mindful that any procurement recommendations from such a study would need to be considered in conjunction with any potential changes resulting from proposals to redesign ERCOT's existing ancillary services.

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

TIEC does not have analysis quantifying these impacts, but observes that the federal Production Tax Credit (PTC) for wind generation has distorted the economics of wind resources and has lead to wind development at a higher level than would otherwise be economically justified. The PTC also leads to bidding behavior that can suppress market prices at certain times, particularly when there is congestion. This type of behavior most directly affects off-peak pricing, which is not as critical a component of the Peaker Net Margin calculation.

## III. RESPONSE TO COMMISSION QUESTIONS ON LARGE DC TIES

<u>**Transmission Planning**</u>

- ***How should the uncertainty of whether DC Ties will be exporting or importing be addressed in transmission planning?***
- ***What relationship exists between ownership of transmission equipment (including converter stations) and cost responsibility for transmission upgrades? What relationship, if any, should exist?***

- ***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.***

- ***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?***

- ***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?***

The answer to these questions will likely be case-specific and depend on the particular DC Tie, its purposes and capabilities, the type of entity owning and operating the facility, and the related transmission and market impacts.

For transmission planning, conservative assumptions should be used regarding using DC Tie imports to maintain reliability. Unlike generation planning, where generation is expected to match peak load with an extra margin of reserves to address contingencies, there is no "reserve margin" assumed in transmission planning. This is a fundamental difference. Because there is no reserve margin, transmission planning must be designed to ensure that the transmission grid can withstand conditions that are extreme, but still reasonably likely to occur. ERCOT has limited control over DC Ties and, therefore, should be cautious modeling DC Tie imports when identifying and planning reliability projects. Regarding the transmission investment that a new (or expanded) DC Tie might require to support its import and export activities, this could likely be isolated through sensitivity studies in the planning process. The Commission should examine whether the current treatment of DC Ties properly assigns transmission costs to these facilities.

From a reliability standpoint, planning transmission around large DC Ties can be challenging because activity over the ties will not be directly related to weather and, therefore, is not as susceptible to accurate forecasting as load patterns within ERCOT. DC Tie exports are typically curtailed and reversed to import power when the an Energy Emergency Alert (EEA) is in effect. As noted in Section 6.9.5.4(4) of the Protocols, "During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using the DC Ties or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with NERC scheduling guidelines." While this limits export activity and maximizes import activity when the system is in EEA, areas of the transmission system may be overloaded at times when an EEA is not in effect, when there is plenty of available energy and capacity on a system-wide basis. This could be particularly true for transmission surrounding a large DC Tie. Unlike typical transmission system usage, heavy DC Tie activity may occur in off-peak periods when it is economic to export power, which could create unexpected congestion and overloading issues without appropriate planning and coordination. To date, the relatively limited size and number of DC Ties has not created significant problems in these areas. But as larger DC Ties seek to interconnect to the system, the Commission will need to make policy decisions about the level of transmission that should be constructed to support DC Ties, who should pay for it, and what additional limits might be appropriate for export activity over those ties. There would likely also need to be an evaluation of any ancillary service impacts and other operational treatment related to DC Ties. For example, the ERCOT protocols currently require ERCOT to use the Reliability Unit Commitment (RUC) process to support DC Tie exports. This could create significant market problems when applied to larger DC Ties.[6]

Because DC Ties have the potential to fundamentally alter the ERCOT energy and ancillary services markets, and to impact the reliability of the ERCOT system, TIEC encourages the Commission to take a hard look at the potential impacts of additional DC Ties and whether there should be additional study and approval requirements for these types of facilities and the entities that own and operate them.

**Investment in Transmission System**

- ***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?***

- ***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 (RRS), who should pay for the increased costs of the RRS? How should increased costs be recovered?***

[6] *See* Protocol Sections 5.1(1), 5.5.2(1) and 5.5.2 (9)(b).

See comments above.

**Market**

- ***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?***

See comments above.

**Registration**

- ***Does PURA enable the Commission to regulate merchant DC Ties and the provision of transmission service to those ties?***

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

TIEC believes that appropriate regulation of DC Ties is an issue that should be considered further by the Commission. Under PURA, a person that owns or operates transmission facilities in Texas, for compensation, is an electric utility subject to the Commission's regulation.[7] On its face, this definition includes any entity owning or operating a DC Tie for compensation in Texas.[8] The Commission has full authority over the service and rates of electric utilities within Texas, including authority to issue or refuse to issue a Certificate of Convenience and Necessity (CCN) for new services or facilities.[9] This regulatory authority would appear to encompass both new and existing DC Ties. The Commission also has authority over transmission and distribution utilities that may need to construct upgrades to support activity over the DC Ties, so the Commission could also exercise regulatory authority over DC Ties through this avenue.

However, given that the Commission lacks CCN authority over municipally owned utilities (MOUs), it is possible that a DC Tie could be constructed and operated without

[7] PURA § 31.002(6).

[8] TIEC is not aware of any exception to this definition that would readily apply to a DC Tie.

[9] *See* PURA § 37.051. TIEC does not believe that a transmission-only utility can exist outside ERCOT under Texas law. *See, e.g., Application of Entergy Texas, Inc., ITC Holdings Corp., Midsouth Transco LLC, Transmission Company Texas, LLC and ITC Midsouth LLC for Approval of Change of Ownership and Control of Transmission Business, Transfer of Certification Rights, Certain Cost Recovery Approvals, and Related Relief,* Docket No. 41223, TIEC Reply Brief at 4-7 (May 10, 2013).

Commission oversight, or that facilities to support DC Tie exports could be constructed by an MOU without an opportunity for Commission review. TIEC urges the Commission to consider whether it has the statutory authority necessary to ensure that the public interest is protected with regard to entities that want to construct, own and operate DC Ties to ERCOT. In addition, because the purposes, operations, and rates charged for the use of DC Ties can vary widely, the Commission should also consider whether its existing authority is sufficient to protect Texas electricity consumers with regard to DC Tie activity.

## IV. CONCLUSION

TIEC appreciates the opportunity to submit these comments, and looks forward to working with the Commission and other parties to consider these issues in more detail at the upcoming workshop.

Respectfully submitted,

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