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ERCOT PLANNING AND SYSTEM COSTS ASSOCIATED WITH RENEWABLE RESOURCES AND NEW LARGE DC TIES	§ § § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

INITIAL COMMENTS OF ONCOR ELECTRIC DELIVERY COMPANY LLC

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

Oncor Electric Delivery Company LLC ("Oncor") submits the following Initial Comments in response to the Request for Comments by the Public Utility Commission of Texas ("Commission") filed August 13, 2014:

I. INTRODUCTORY COMMENTS

It is imperative that utilities, the Commission, and the Electric Reliability Council of Texas ("ERCOT") begin to see the future of the grid as how it will be and not just how it has been. The grid is dynamic; its components constantly changing. As generators distance from coal and nuclear, ever increasing ERCOT's reliance on natural gas and renewable energy, the grid must adapt to this change. This will require changes in transmission planning, a constant focus on maintaining grid flexibility, and utilization of new, emerging technologies.

Transmission grid planning must adapt to the changing landscape. Future planning must address the uncertainties that come with renewable resources. Some of this mitigation can occur simply by changing the way grid planning occurs. While the economics of renewable resources and natural gas prices can change quickly, transmission infrastructure does not. Planning for the future should not be limited by the conditions of today but should prepare the grid for a future where the types of generation resources, and their impacts, may be substantially different than exist today.

Flexibility must be a foundational principal in transmission grid planning. The utility of this broadened, flexible perspective to transmission planning can already be seen in the CREZ projects. While primarily designed to facilitate the integration of renewable wind energy, the CREZ lines are already serving all types of generation including wind, solar, clean coal, and natural gas fired plants. Additionally, these lines are serving substantial load growth in West Texas. The grid and its transmission planning functions must maintain a broad enough scope to realize these corollary benefits that can come from future transmission infrastructure.

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A wide variety of transmission technologies will also be required to mitigate the impacts of renewable generation and a changing generation landscape. These transmission technologies will include static synchronous compensators ("STATCOMs"), static var compensators ("SVCs"), synchronous condensers, synchrophasors, high speed control schemes, batteries, series compensation, and others. Transmission service providers ("TSPs") will utilize these facilities to stabilize the grid and provide widespread regional benefit. While several of these technologies may be relatively new, they have the potential to substantially mitigate the potential threat to grid reliability that is bound to arise as the market migrates from coal and nuclear to renewable and natural gas.

II. SPECIFIC COMMENTS

The issues for which Oncor has specific comments are addressed below:

A. RENEWABLE RESOURCES

1) 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?

The production cost savings test as utilized by the Commission today was added to PURA[1] in 2011.[2] Given the passage of time, changes to the ERCOT market, data gathered, and lessons learned, re-evaluation of the production cost saving test and its applicability is likely appropriate. At this time, Oncor does not have specific comments on what changes to the test may or may not be appropriate, but reserves its right to respond to the other filed comments.

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.

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)?**

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016 (West 2007 & Supp. 2014) ("PURA").

[2] *See id.* § 37.056 (d) (added by H.B. 971, 82nd Leg., R.S. (2011)).

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?**

Please see the prior comments above.

2) **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?

A stable, reliable electric grid is in the interest of all market participants. The burdens of grid instability and benefits of a stable market for electricity are felt by all. As such, the cost of maintaining grid stability should be allocated through the established transmission cost recovery system.[3] The electric grid is dynamic. It is constantly changing and adapting to new load and generation resources. The existing system of transmission cost recovery allows the cost for equipment and facilities that benefit the electric grid as a whole to be paid for proportionally by those who benefit from the stability of the grid.

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?**

Since the devices that will be used to provide grid stability are assets that will be installed on the transmission system, they are transmission assets and should be treated as transmission costs under the established transmission cost recovery system.[4] These facilities could include transmission lines, capacitors, reactors, STATCOMs, SVCs, synchronous condensers, synchrophasors, high speed control schemes, batteries, series compensation, and numerous other new and developing technologies.

3) **Market**

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

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[3] *See* P.U.C. SUBST. R. 25.192.

[4] *See id.*

i. **Are there 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 increases?**

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?**

Oncor has no specific comments at this time.

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

Oncor has no specific comments at this time.

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

Oncor has no specific comments at this time.

B. DC TIES

1) <u>Transmission Planning</u>

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

Oncor's internal planning process is to model the DC Ties with both maximum importing and maximum exporting flows when performing transmission planning activities. Looking at both of these extreme cases in the planning process allows for a full picture of potential transmission scenarios to be considered in the decision-making process.

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

The current relationship for existing DC Ties in which Oncor has an ownership interest is that the responsibility for upgrades to the tie is proportional to ownership interest. Upgrades to any other transmission facilities would be the responsibility of the owning TSP. (*See* comments on Investment in Transmission System below.)

Oncor does not have any comments at this time on what relationship should exist for potential future DC Tie facilities.

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.

The potential grid stability problems that could result from additional DC Ties are extremely case specific. The size, location, and configuration of a particular DC Tie will determine whether it has severe stability implications or no implications at all. As such, each potential tie must be carefully studied so that an individual determination of impacts may be made.

Has a ceiling on the number or size of DC Tie installation 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?

As mentioned above, the size, location, configuration, and numerous other details regarding a potential DC Tie are necessary to determine what upgrades if any would be necessary.

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?

Oncor has no specific comments at this time.

2) <u>Investment in Transmission System</u>

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?

To the extent upgrades are transmission facilities, the upgrades should be the responsibility of the constructing TSP under PURA, the Commission's Substantive Rules, and the ERCOT Nodal Protocols ("ERCOT Protocols"). Although the DC Tie may be the impetus for the transmission upgrades, because of the integrated nature of the ERCOT grid the transmission facilities will be utilized when importing/exporting through the DC Ties but also for the grid generally. The new transmission facilities may provide opportunities to serve future load, interconnect additional generation, or simply provide additional transmission paths within the state during contingency situations. Thus, these facilities should fall under the existing transmission cost recovery system as transmission assets.

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?

Oncor has no specific comments at this time.

3) <u>Market</u>

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?

Oncor has no specific comment regarding the mechanism that should be employed if a DC Tie owner is required to bear a portion of the cost of transmission system investment to accommodate power flows over the ties. To the extent transmission investment is required, however, the proper TSP under applicable provisions of PURA, the Commission's Substantive Rules, and the ERCOT Protocols would build the necessary transmission facilities and recover those costs through the traditional mechanisms.

4) <u>Registration</u>

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.

Oncor has no specific comments at this time.

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

Oncor is unaware of what might qualify as a "merchant DC Tie" under state or federal law or whether any such entity is recognized under existing state or federal law. From Oncor's perspective, its obligations as a TSP under state law are to serve transmission service customers.[5]

[5] The Commission has defined a "transmission service customer" as a:

> [TSP], distribution service provider, river authority, municipally-owned utility, electric cooperative, power generation company, retail electric provider, federal power marketing agency, exempt wholesale generator, qualifying facility, power marketer, or other person whom the commission has determined to be eligible to be a transmission service customer. A retail customer, as defined in this section, may not be a transmission service customer.

P.U.C. SUBST. R. 25.5(142).

The ERCOT Protocols carry forward this concept.[6] Additionally, under limited circumstances, Oncor has obligations to provide transmission services to certain entities under federal law arising out of its ownership interests in certain discrete high-voltage DC Tie and associated assets subject to Federal Energy Regulatory Commission ("FERC") jurisdiction.

Oncor's state law transmission service obligations are sourced primarily in PURA §§ 35.004(a)-(b) and 39.203(a).[7] Commission Substantive Rules §§ 25.191 and 25.195 further govern and define Oncor's transmission service obligations. Section 25.191(c) provides the following with respect to DC ties:

> Transmission service shall be provided pursuant to Division 1 of this subchapter, commission-approved tariffs, the ERCOT protocols and, for TSPs subject to [FERC] jurisdiction, FERC requirements. Transmission service under Division 1 of this subchapter includes the provision of transmission service ***to an entity that is scheduling the export or import of power from the ERCOT region across a DC tie.***[8]

In Oncor's experience, the entities that schedule exports or imports of power from/into the ERCOT region across DC ties are ERCOT-registered power marketers and/or qualified scheduling entities.

Outside of PURA, Oncor's only other transmission service obligations are to serve certain entities under prior FERC orders issued pursuant to sections 210-211 of the Federal Power Act ("FPA")[9] based on Oncor's ownership interests in a discrete set of high-voltage DC

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[6] ERCOT Nodal Protocols § 1.6.1 ("Open access to the ERCOT Transmission Grid must be provided to all Eligible Transmission Service Customers by [TSPs] and ERCOT under these Protocols and the P.U.C. Substantive Rules, Chapter 25, Substantive Rules Applicable to Electric Service Providers, Subchapter I, Transmission and Distribution.").

[7] *See also* PURA § 35.005(a)-(b) (establishing the Commission's authority to, among other things, order the provision of transmission service at wholesale); *Texas Municipal Power Agency v. Public Utility Commission of Texas*, 253 S.W.3d 184, 194 (Tex. 2007).

[8] Emphasis added; *see also* Oncor Electric Delivery Company LLC, Tariff for Transmission Service § 4.6.1.1 ("Intrastate Wholesale Transmission Service Limitations - Company does not provide service to Customer where any part of Customer's Electrical Installation is located outside the State of Texas or is connected directly or indirectly to any other electric lines, all or part of which are located outside the State of Texas, other than through certain high-voltage interconnections constructed under orders of the [FERC].").

[9] 16 U.S.C. § 824i; 16 U.S.C. § 824j (2012).

Tie and associated assets (*e.g.*, East HVDC Tie in Titus County). Generally speaking, these FERC orders require interconnection and wheeling service upon application by, among others, an "electric utility" as defined by the FPA[10] without subjecting Oncor or other ERCOT utilities to FERC's generally applicable or plenary jurisdiction. As Oncor's Tariff for Transmission Service To, From and Over Certain Interconnections provides at § 2.2: "Company will provide wholesale transmission service to other electric utilities, federal power marketing agencies, power marketers, exempt wholesale generators, and qualifying facilities, in accordance with the provisions of this TFO Tariff."

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

Please see prior comments above. Oncor has no additional specific comments at this time.

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

Please see prior comments above. Oncor has no additional specific comments at this time.

[10] Under the FPA, an 'electric utility' is defined as "a person or Federal or State agency . . . that ***sells*** electric energy." 16 U.S.C. § 796(22) (emphasis added).

Respectfully submitted,

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