

Transmission Update

June / July 2005

Summary

- ✓ Welcome to the Third NWCC Transmission Update! Kevin Porter of Exeter Associates led the June 14, 2005 Transmission Update Conference Call, which featured expert speakers providing their insights into key transmission issues affecting wind energy, with an opportunity for discussion and questions. The current edition is the third to follow the new Transmission Update format, in which the written brief is being distributed after the call to conference call participants, other NWCC members and participants, and to interested NWCC observers.
- ✓ This edition focuses on two issues that are critical to their respective regions, but have important ramification for other areas of the country as well: market redesign initiatives involving the Electric Reliability Council of Texas (ERCOT), and Southern California Edison's (SCE) proposal to create a “renewable resources trunk facility” to access potential wind capacity in southern California.
- ✓ Eric Schubert from the Public Utility Commission of Texas discussed ERCOT’s potential redesign to address problems highlighted in its current zonal system. Potential options being considered include making partial fixes to the zonal model or going to a nodal design such as used in PJM.
- ✓ Patricia Arons from SCE discussed their filings with FERC and the California PUC that would create a new classification of transmission facility, a “Renewable Resource Trunk Facility”. This could potentially facilitate transmission access to designated areas with a good resource. Under this new designation, the transmission owner would be able to recover costs for implementing this designation of transmission through rates under the California ISO tariff. This may be an example with implications for other areas looking to connect windy areas to the grid.
- ✓ The next Transmission Update call will be August 9 at 1 pm Eastern. Please mark your calendars!

Texas

Market Redesign in ERCOT

Background

The Electric Reliability Council of Texas (ERCOT) serves as the Independent System Operator for Texas, administers the settlements of participants in the state's deregulated wholesale market, and acts as the transaction hub for electricity suppliers serving competitive retail markets. ERCOT currently operates a zonal or portfolio market that was implemented in July 2001, as a decentralized dispatch system. The portfolio system makes congestion and grid management difficult, and the Texas Public Utilities Commission is examining alternative market design proposals to improve the existing zonal system.

Zonal and Interzonal Congestion

Under the current system, qualified scheduling entities (QSEs) submit balanced generation and demand schedules for each zone to meet the demand forecast for every hour. ERCOT fills in with any required out-of-order dispatch or grid management services as needed. The QSEs have the flexibility to select which resources should be deployed and at what location within the grid. ERCOT does not receive the specific details from QSEs as to which units are being used and when, nor is ERCOT made aware of the operating parameters and ramp rates of the units that are committed. As a result, ERCOT has to guess which resources a QSE will use, resulting in greater deployment of ancillary services and contributing to congestion. While ERCOT can call on specific must-run generating units for reliability and grid support, the units selected may not always be the most efficient units deployed.

In addition, interzonal congestion (congestion that spans at least two zones) costs are charged directly to participants. Intrazonal congestion (congestion within a zone) costs, though, are uplifted on an ERCOT-wide load ratio share basis to all customers in that particular zone. At the time the ERCOT market was designed, it was thought that intrazonal congestion would be a localized, random event. However, intrazonal congestion has been frequent and persistent, and at times, it has been determined that market participants take actions to create congestion in order to be paid to alleviate it.

Siting Generation and Transmission

In its current configuration, ERCOT's market design does not send price signals that effectively encourage efficient generator siting. A rush of combined cycle natural gas plants in 1999 and wind projects in 2001, concentrated in particular zones, created areas of "generation pockets" that are underserved by sufficient transmission resources to move their generation to load centers. The 750 MW of wind projects located in far west Texas near McCamey, Texas, is a commonly cited example of this: in McCamey, wind generation outstripped transmission capacity to such an extent that in 2001, ERCOT ordered curtailments by these generators to prevent overloading the local transmission system.

The Texas PUC is in the midst of evaluating options for redesigning the ERCOT market. One option is to maintain the zonal market but require QSEs to make unit-

specific schedules, instead of the portfolio approach. This would allow ERCOT to calculate load flows and more efficiently call on resources for grid support and ancillary services.

The second option would shift the Texas electricity market to a nodal design, similar to the market design for PJM. The nodal market would include a day-ahead market to calculate hourly settlements based on bids and offers. While energy would be dispatched at the unit-level with nodal pricing, load settlements would still be based on load zones, with nodal prices averaged to arrive at a zonal clearing price.

**Moving from a Zonal to a Nodal model to manage
commercially significant transmission constraints in ERCOT**

ERCOT has over 1,400 MW of wind capacity installed, with 2,000 MW expected to be in operation by the end of 2005. If ERCOT shifts to a nodal system, wind power facilities located away from load centers may receive lower prices for their generation, absent new transmission to transmit that wind power to load centers. However, it may encourage the development of more moderate wind resources located close to load centers, as these wind projects may receive a higher price.

A decision on whether to modify ERCOT's zonal market or drop it in favor of a nodal market design is expected sometimes this year, perhaps as soon as this summer.

For more information on revisions to ERCOT's system market design:

Eric Schubert, Senior Market Economist for the Texas Public Utilities Commission, joined the June 14 conference call to discuss the market design alternatives for ERCOT. For more information, email eric.schubert@puc.state.tx.us, (512)-936-7398. See also the PUC docket on ERCOT wholesale market design issues at <http://www.puc.state.tx.us/electric/projects/28500/28500.cfm>.

California

SCE's Renewable Resource Trunk Line Proposal

Background

The Tehachapi area in Central California boasts more than 4,600 wind turbines with 645 MW of capacity, generating approximately 1.4 billion kilowatt-hours of electricity per year. The wind power is connected via a network of 66 kV lines traversing the Tehachapi region. The California Energy Commission estimates that Tehachapi has a potential wind resource capacity of 4,000 MW. This area has been of great interest to regulators, load serving entities, and wind energy advocates and developers alike thanks to its relative proximity to markets and the potential it has to contribute to the state's Renewable Portfolio Standard (RPS), which requires investor owned utilities to provide 20 percent of retail energy sales from renewable resources by the year 2017. In spite of this, development of this resource has remained untapped because of transmission limitations in the area.

The essential problem facing improving transmission access to the Tehachapi wind resource remains how to manage risks associated with providing transmission for projects that have not, as yet, been proposed. With the enactment of the RPS in California, Southern California Edison (SCE) has been working closely with wind developers to identify possible projects and regions of interest in Tehachapi in an effort to create a transmission plan to supporting construction of wind power facilities. Furthermore, the state RPS statute directed the California Public Utilities Commission (CPUC) and utilities to seek recovery of costs related to transmission facilities through general retail or wholesale transmission rates, and the CPUC ordered SCE to file an application for CPUC approval to construct transmission in Tehachapi.

Planning for New Transmission

Rather than building transmission to serve each of a large number of potential future wind energy facilities, SCE is contemplating upgrading its transmission system to provide for access to a new substation in the wind resource area that would serve these potential facilities. Current plans call for three segments, specified in more detail below.

Segment 1 of the project would be a 25.6-mile-long 500 kV transmission line between the existing Antelope and Pardee substations. The project would connect a potential 201 MW wind project with a proposed in-service date of December 2006. Segment 2 would be a new, 17.8-mile-long 500 kV line between the existing Antelope and Vincent substations to run in parallel with existing transmission lines. The final phase of the project, Segment 3, includes the construction of two new substations in the Tehachapi area and corresponding transmission lines to the Antelope Substation.

Other than the potential 201 MW wind project, SCE's transmission application does not include information on the number of wind projects that would benefit from the project. Indeed, transmission would be built to access the wind resources at Tehachapi before specific wind projects are announced. SCE filed an application

with the CPUC in December 2004 for the first segment. SCE expects to file application for the other two segments at the CPUC later this year.

Cost Recovery and Risk Management

In a separate filing submitted to FERC on March 23, 2005, SCE requested that the three proposed transmission projects, the Antelope Transmission Projects, receive guaranteed cost recovery within the rolled-in rates of the California Independent System Operator (CAISO). SCE's usual practice is to submit applications for permits to construct transmission only after interconnection agreements have been signed.

While Segments 1 and 2 are upgrades to existing high-voltage, network transmission facilities or that will operate in parallel with such facilities, Segment 3 would resemble more of a generation tie-line in that energy would flow in one direction, unless all generation interconnected to Segment 3 stopped. In that case, no energy would flow at all on Segment 3 except for the line charging current. While interconnecting generators would normally pay the costs of such a line, wind generators would not likely be able to pay the large capital costs of Segment 3, and that incremental transmission upgrades based on first-in-queue would not be effective in renewable-rich locations such as Tehachapi. For these reasons, SCE suggested the creation of a new category, the Renewable Resources Trunk Facility.

In many ways, this is a question of what comes first: generation or the transmission to serve it. In addition to concerns over cost recovery, under current FERC rules, SCE's shareholders might be required to absorb up to 50 percent of the transmission expansion costs as an abandoned plant if the wind power projects do not come to fruition. Therefore, building the transmission lines prior to generator development places risk on SCE. Wind generators, though, cannot afford to finance the extensive transmission upgrades that are necessary to tap the full wind potential in Tehachapi, although some wind developers may be able to finance individual interconnections for a specific wind project. Without sufficient transmission to connect the wind projects to the load centers in and around California, the full wind potential in Tehachapi would not likely be developed.

The SCE FERC filing was intended to mitigate the risk on the part of SCE and potential wind developers. In their FERC filing, SCE asked that FERC issue a declaratory order addressing four issues:

- Assurance that SCE is entitled to roll-in the cost of the three transmission projects into the CAISO high voltage charges;
- Assurance that SCE will be permitted to recover the cost of the transmission projects whether or not generation develops as expected;
- Assurance that SCE will be permitted to recover 100 percent of the costs even if one or more projects are abandoned or cancelled; and
- Clarification that the Antelope to Tehachapi transmission line and associated transmission facilities are eligible to be placed under the operational control of the CAISO.

Furthermore, SCE argued that this type of transmission project, one that is build

specifically to bring renewable generators into load areas, should have special consideration by FERC.

Petitioning FERC for a new classification

At issue is whether or not the transmission project, particularly Segment 3, should be classified as a generation tie-line, a network upgrade, or as a Renewable Resources Trunk Facility line. Because of the manner in which the lines would need to be constructed, some would have difficulty meeting the requirements for being classified as network upgrades, making them eligible for cost recovery through CAISO rates. If the new facilities are found to be generation tie-lines, existing regulations prohibit the transfer of their costs to the CAISO, and would have to be paid for by the wind generators as part of an interconnection agreement with SCE. As noted before, the wind power developers cannot afford the high cost of the transmission upgrades. A Renewable Resource Trunk Facility would provide a method to meet the state's renewable energy requirements while removing some cost recovery barriers. However, there are concerns that classifying the facilities as a Renewable Resource Trunk Facility may be found to be discriminatory against non-renewable facilities, providing a competitive advantage to renewable resources.

Another element of the filing is the size of the transmission projects. SCE argues that while current plans for potential wind capacity requires only a 220 kV line, the facilities should be built for 500 kV and operated at 220 kV. The renewable energy requirements of the California RPS and the high level of interest in wind power for the Southern California area may be a good indication that there could be additional wind projects developed over the next several years. SCE believes that installing the towers and conductors to operate at 500 kV will save future demolition and rebuilding costs.

Comments filed thus far in the FERC filing can be classified into six categories. The renewable energy groups have supported the filing, as well as regulators. The other investor owned utilities are also supportive and are hoping to make use of the potential capacity to help meet the 20 percent RPS requirement. The non-renewable electricity generators are not supportive. The CAISO is neutral, supporting the declaratory order as it relates to segments 1 and 2 but not segment 3. Neither the municipal electricity companies nor the rural electric cooperatives are supportive of the project, since they will pay the higher transmission access charges from the CAISO but would not see the benefit from wind energy projects in Tehachapi.

FERC Order and Implications

On July 1, 2005, FERC determined that Segments 1 and 2 are network upgrades and eligible for rolled-in rate treatment. However, FERC found that Segment 3 was not eligible for rolled-in rates. FERC ruled that Segment 3 resembles more of a generation-tie facility than a network upgrade, and therefore is not eligible for rolled-in rate recovery through the CAISO's TAC charge. FERC found that SCE did not provide how all users of the CAISO grid would benefit from Segment 3, nor how Segment 3 provides reliability or other benefits to the grid. In addition, the CAISO had not determined whether Segment 3 would be transferred to the CAISO. Given these circumstances, FERC denied SCE's petition to create a new category of transmission facilities, i.e., the renewable resource trunk facility.

FERC deferred ruling on SCE's application for an advance determination of prudence, stating that SCE can apply for a determination of prudence once SCE receives a certificate of public convenience and necessity from the CPUC for the proposed transmission facilities. FERC did say SCE can recover prudent costs for Segments 1 and 2, even if the facilities are abandoned or cancelled. FERC also found that the abandoned plant policy articulated in earlier FERC orders does not apply here. FERC determined that SCE is operating in a different environment than the utilities in the FERC order that instituted FERC's abandoned plant policy. FERC noted that SCE does not control the decision of wind developers to develop or not develop wind resources at Tehachapi, nor does SCE's shareholders receive some of the earnings from future wind development at Tehachapi. In addition, the CPUC directed SCE to file a permit application for Segments 1, 2 and 3. Given these factors, FERC determined that SCE is facing more risk because of factors beyond SCE's control and should not bear the risks of the Tehachapi transmission upgrades.

In its order, FERC maintained its focus on whether the proposed transmission upgrades would be part of the overall transmission system and provides overall reliability benefits to the transmission network, or whether the proposed transmission upgrades do not have identifiable network benefits and are intended to interconnect prospective generators. In doing so, FERC did not address the arguments raised by intervenors on the complexities of multiple generators planning and financing transmission while being market competitors. FERC did, though, remove a potential roadblock by modifying its abandoned plant policy. The Commission also noted that under Order 2003, transmission providers may pay for transmission upgrades and receive transmission credits plus interest, which is the reverse of the usual procedure of requiring generators to pay these costs and being reimbursed over time by transmission providers. Absent assurances of advance cost recovery, though, it is uncertain that a transmission provider will underwrite significant transmission upgrade costs.

Before FERC issued this order, there was some preliminary discussion that a renewable resource trunk line could service geothermal resources in the Imperial Valley or wind resources elsewhere in California. With FERC's order, the options have narrowed somewhat to either a finding by FERC of network benefits (for rolled-in rate recovery), for transmission owners to build the transmission or upgrades and be reimbursed by generators with interest, or for generators to either finance upgrades on their own, or to have generators band together and jointly finance new transmission or upgrades. In his dissent, outgoing FERC Chair Pat Wood suggested that the California ISO file a proposal for a region-wide cost allocation policy, which could be another alternative.

For more information on SCE's filing to FERC, please contact Patricia Arons, Manager of Transmission and Interconnection for Southern California Edison (patricia.aron@sce.com), who participated on the June 14th conference call to discuss the SCE filing to FERC and the background of the three proposed transmission projects.

Federal Energy Regulatory Commission, *Southern California Edison Company's*

Petition for Declaratory Order, Docket No. EL05-80-000, March 23, 2005.
Information on the FERC filing can also be obtained at FERC's eLibrary website, http://elibrary.ferc.gov/idmws/docket_search.asp, under EL05-80. FERC's July 1, 2005 order can be found at <http://www.ferc.gov/EventCalendar/Files/20050705074237-EL05-80-000.pdf>.

Next Update: August 9, 2005

The next NWCC Transmission Update will be held on August 9, 2005, at 1 pm Eastern.

Please email Kevin (porter@exeterassociates.com) or Miles Keogh (mkeogh@resolv.org) with any suggestions for topics or ways to improve the call.