BEFORE THE
UNITED STATE OF AMERICA
ENERGY REGULATORY COMMISSION

Competitive Transmission Development	**)**	**Docket No. AD16-18-000**
Technical Conference	**)**	

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TOPIC: INTRODUCTORY REMARKS
PANEL 5 ADDRESSING "REGIONAL TRANSMISSION PLANNING AND OTHER TRANSMISSION DEVELOPMENT ISSUES"

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Good afternoon. My name is Omar Martino. I am the Director of Transmission Strategy within the Valuation and Transaction Group at EDF Renewable Energy, Inc.

EDF Renewable is a subsidiary of Électricité de France, S.A., a French electric utility company. In North America, EDF Renewable has developed over 6 gigawatts ("GW") of generation since 2012. EDF Renewable currently owns 3.1 GW of generation, has another 1.1 GW currently under construction and provides operations and maintenance service for another 10.5 GW of generation.

I want to thank the Commission for inviting me to speak today.

Some RTOs and transmission owners have argued it is too soon to assess the effectiveness of Order 1000 for regional and inter-regional effectiveness. We disagree. There is a need to fundamentally change and enhance how transmission is planned and utilized in this nation. RTOs are holding on to many historical ways of doing things that are inhibiting cost effective, efficient and maximum use of the grid. Commission directives are needed to require RTOs to expand the transmission planning concepts in their Tariffs. I will discuss seven areas where regional transmission needs to change. All of these items can be implemented without jeopardizing reliability. Further, these concepts apply to regional and inter-regional transmission planning.

First, regional transmission planning should annually identify persistent binding transmission constraints. Right now, no assessment of congestion occurring in real-time is regularly undertaken by the RTOs. If it is done at all, it is hit or miss or by specific, limited request of a load serving entity. This is a huge problem. Congestion is extremely costly and unnecessary to ratepayers and generation owners. We are seeing congestion at the rate of 30% of what we could provide for specific projects and around $10-12/MWh on basis, *i.e.*, price differentials in the same RTO region between a projects and a trading hub.

RTOs should be required to amend their Tariff to include a Congestion Management Protocol that (1) lists triggers for congestion identification -- such triggers might include (i) M2M payments in excess of $5 million; (ii) price differentials between region and trading hubs of $3-5/MWh; and (iii) curtailment at 200 hours annually; and (2) annually assesses whether an economic transmission upgrade is more cost effective than persistent congestion. The cost of a transmission enhancement is often much less than these type of costs to consumers. This second point would require all benefits to be considered, such as lowered LMP, reliability benefit from unrestricted transmission elements, foregone M2M and redispatch costs, etc. RTOs are not capturing these benefits. RTOs are not capturing and modeling these market conditions.

Second, lower voltage facilities should be included in congestion and economic transmission upgrades analyses. We're experiencing high levels of congestion and curtailment on lower voltages, yet RTOs do not review congestion or consider economic upgrades at lower voltages. Recently, we've seen MISO and PJM address binding constraints on lower voltage facilities (these were the 'quick hits' projects). All RTOs must include lower voltages, down to 100 kV, to consider economic upgrades. Cost allocation must not inhibit this planning tool. Cost allocation can be addressed if there is a Commission directive. Unless and until this is addressed, unresolved congestion and curtailment will remain with the only avenue of relief being interconnection customers filling the gap and funding new upgrades that benefit all other market participants (and with no cost recovery mechanism). This is not just and reasonable.

Third, regional transmission models need to embed network resource interconnection service (NRIS) rights and preserve them for customers that pay for the NRIS network upgrades. RTOs are not doing this. Order No. 888 requires the Transmission Provider to preserve network integration transmission service and firm point-to-point service rights, especially where the transmission customer funds network upgrades. RTOs capture this in regional transmission planning so there is transmission capacity to serve these paying customers. There is no comparable treatment for NRIS for the interconnection customer. This deficiency allows capacity dedicated to the NRIS customer to be eroded and used by others that did not pay for the capacity created by the network upgrade. This also allows new generation to connect to the grid without the RTO considering the level of NRIS already granted to earlier interconnection customers. This results in an underbuilt grid, congestion, curtailment and higher LMP from the inability to use local low-cost resources. Regional transmission planning needs to embed NRIS granted to interconnection customers so such customers can count on the benefit of what they funded; then, when the next generation project is considered, that capacity must be considered unavailable.

Fourth, regional transmission planning should utilize grid modernization and optimization tool such dynamic line ratings (DLR) and phasor measurement units (PMU) to manage congestion in the short term. DLR can monitor variable such as temperature and wind speed in real time.

PMUs provide valuable feedback to grid operators about the state of the grid in real time. These real time sensors can increase reliability and optimize flows on congested lines and even dispatch. The use of DLR and PMUs can also lead to revisit how SCED is operated and wind projects are dispatched (which can respond nearly instantaneously). The current method of dispatch is limited to N-1 conditions, which assumes a contingency in the system. This is not optimal and leads to further and unnecessary congestion. DLR can manage congested lines and optimize flows. PMUs can monitor the grid real time and allow RTO operators "relax" or revisit the N-1 contingency dispatch in use in SCED. RTOs and TOs are not utilizing these tools, but continue to use a static capacity value. This unnecessarily limits use of the grid and needs to be revisited. This is low-hanging fruit that RTOs should be capturing, but are not.

Fifth, the NERC criteria being applied for reliability upgrades needs to be reviewed. RTOs differ in the application of NERC Category A, B and C contingencies criteria. This can lead to an under-developed grid, especially when new generation is being assessed. One RTO may properly shore up the grid, whereas the neighboring RTO may not, all depending on how they choose to apply NERC criteria at study conditions. A project located at the seam suffers from an under-developed grid because adequate transmission is not being put in place to account for each new generation project. This, in turn, leads to more congestion and curtailment.

Sixth, a standard 3 or 5% distribution factor (DFAX) should be used. DFAX is a measure of the impact on transmission element from a proposed generation project. RTOs are not employing a lower enough DFAX. This allows new generation to connect without properly shoring up the grid. We have seen this occur over and over, with the result that generation projects do not experience the level of use that was modeled and for which they paid. Instead, we experience high levels of persistent congestion and curtailment. A lower DFAX will help to avoid this. Again, this is low-hanging fruit.

Seventh, the regional transmission and generation interconnection process should be united, not separate and distinct. The current construct causes transmission to lag behind generation needs. This causes generation to fund upgrades when certain transmission is not timely considered, such as for Public Policy needs or otherwise. The two processes should be linked and holistically resolved in RTO Tariffs. This is do-able. CAISO employs a form of this.

The transmission planning process essentially *only accommodates deliverability for load serving needs*. There is no forethought for transmission to accommodate the region's generation needs. RTOs should determine and describe renewable energy zones or areas of high interest to build generation. These areas should become part of the annual transmission planning process instead of the interconnection process. Transmission planning would identify transmission to *deliver* energy to the RTO footprint, with the interconnection process mitigating any *reliability* concerns at the regional level and in specific areas. In this way, transmission planning and the interconnection process would become truly intertwined.

Thank you, again, for inviting me to speak to you. These are very important concepts. I urge the Commission to provide separate processes to explore these concepts and require RTOs to demonstrate what is needed to implement them. We cannot wait two more years as commenters have suggested. I look forward to your questions.