

of FPA section 211A. Further, as we indicate below, we expect unregulated transmission providers to participate in the open and transparent regional planning processes that we propose to order and note that, if there are complaints about such participation, we will address them on a case-by-case basis.

112. We disagree with the position of the Canadian Electricity Association. EPC Act 2005 did not repeal the reciprocity obligation in Order No. 888. Rather, it granted a new avenue of authority to the Commission to order comparable transmission service from non-public utilities. We are proposing not to exercise this new authority at this time. Rather, we are proposing to retain our reciprocity policy, which was adopted pursuant to sections 205 and 206 of the FPA. By maintaining the same reciprocity requirement for domestic, non-public utilities as for foreign utilities doing business in the United States, the Commission will ensure that foreign entities will continue to be treated no less favorably than domestic, non-public utilities.

V. Proposed Modifications of the OATT

A. Consistency and Transparency of ATC Calculations

113. In Order Nos. 888 and 889, the Commission directed transmission providers to offer their unused transfer capability to the market and to post the amount of ATC¹⁰⁷ on OASIS. At the time those orders were issued, the Commission noted that formal methods did not exist for calculating ATC, but recognized that there were industry efforts

¹⁰⁷ See supra note 7.

underway to develop a consistent, industry-wide method for calculating it.¹⁰⁸ Instead of prescribing a specific methodology for calculating ATC in Order Nos. 888 and 889, the Commission encouraged the industry efforts and required that transmission providers base their ATC calculation methodologies on current industry practices, standards and criteria.¹⁰⁹ In addition, the Commission directed transmission providers to include a description of their ATC calculation methodologies in Attachment C of their tariffs.

114. Ten years later, however, although some progress has been made, the industry still has not developed a consistent, industry-wide methodology for evaluating ATC. In the intervening years, the industry, working through the North American Electric Reliability Council (NERC), has adopted a general definition of ATC, which establishes a basic methodology for evaluating ATC. NERC also has developed a set of guiding principles for calculating ATC and has encouraged further consistency of ATC calculation methodologies on a regional level. NERC defines ATC as the transfer capability remaining on the system for further commercial activity over and above already committed uses. This value is determined by deducting existing transmission commitments (ETC)¹¹⁰ (including transmission reservations, network and retail customer

¹⁰⁸ Order No. 889 at 31,607.

¹⁰⁹ Id.

¹¹⁰ NERC does not have a formal definition or standard methodology for ETC.

service), capacity benefit margin (CBM),¹¹¹ and transmission reliability margin (TRM)¹¹² from total transfer capability (TTC).¹¹³ However, NERC's calculation methodology is not prescriptive; it establishes a framework for evaluating ATC, which leaves open to each transmission provider's interpretation and discretion the specific algorithm, data inputs and assumptions needed to assess ATC.¹¹⁴ Consequently, transmission providers

¹¹¹ NERC defines CBM as the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities, whose loads are located on that transmission service provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a load-serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the load-serving entities only in times of emergency generation deficiencies. See North American Electric Reliability Council, *Glossary of Terms Used in Reliability Standards*, (Effective April 1, 2005), (NERC Glossary) available at ftp://www.nerc.com/pub/sys/all_updl/standards/sar/Glossary_07Feb06.pdf.

¹¹² NERC defines TRM as the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. See NERC Glossary.

¹¹³ NERC defines TTC as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. See NERC Glossary.

¹¹⁴ See NERC, *Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market* (1996) available at ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/atcfinal.pdf.

have developed numerous ways to evaluate ATC using their own algorithms, data and modeling assumptions.¹¹⁵

115. Although transmission providers across the Nation have developed various methodologies, in general, there are two main approaches to calculating ATC used in the industry. The first is the contract path approach, which is more commonly used by transmission providers in the Western Electricity Coordinating Council (WECC) region.¹¹⁶ The contract path methodology derives ATC directly from predetermined TTC, ETC, CBM, and TRM values derived consistent with contract path transmission rights. The second method is the flowgate¹¹⁷ approach, which is used more widely in the Eastern Interconnection.¹¹⁸ The flowgate methodology is based on physical power flow models. The flowgate calculation first determines AFC and then converts AFC into ATC and derives TTC for the OASIS posting. The differences between the two approaches

¹¹⁵ See supra note 59.

¹¹⁶ See, e.g., Determination of Available Transfer Capability within the Western Interconnection (June 2001), available at <http://www.wecc.biz/documents/library/procedures/ATC-aprdec01.pdf>.

¹¹⁷ A flowgate is a designated point on the transmission system used in the modeling of power flows. While NERC currently does not have a formal definition for AFC, the power industry commonly defines AFC as a measure of the capability remaining on a flowgate for future uses, after considering the effect of prior sales. Mathematically, the industry measures AFC as $AFC = \text{Flowgate rating} - [(\text{base case flow}) - (\text{impacts of existing reservations})] - \text{Flowgate}_{CBM} - \text{Flowgate}_{TRM}$.

¹¹⁸ See, e.g., PJM Manual 2: Transmission Service Request (April 14, 2005), available at: <http://www.pjm.com/contributions/pjm-manuals/pdf/m02v08.pdf>

may not result in significantly different ATC values if consistent data inputs and industry acceptable modeling assumptions are used. Without a consistent and transparent approach to evaluating ATC, transmission customers will remain wary when service is denied and transmission providers will be the subject of suspicion and heightened scrutiny, especially given the increasingly congested state of the Nation's electric grid.

Consistency

116. Generally, transmission providers calculate ATC by creating a base model of their system using a set of data inputs and assumptions, which are determined by the transmission provider. The transmission provider uses the model to perform various computer simulations of the operations of its system to determine the levels of transfer capability available on the system. The types of data and assumptions used in the models include, for example, facility ratings, the operating status of facilities, and generation dispatch, which might be supported by history, transmission plans, or the judgment of the transmission provider. For example, a transmission provider could use its judgment to reduce a facility rating or model certain facilities as out of service, which would have the effect of calculating a lower TTC value. A transmission provider also may use generation dispatch assumptions to limit transfer capability that otherwise would have been available to independent generators, thereby favoring the transmission provider's own generation. A transmission provider usually assumes that designated network resources are dispatched in economic merit order. However, a transmission provider has the discretion to decide which of the generators that are not designated network resources

will be modeled in-service. Assumptions like these influence the loading on transmission lines in the model and heavily influence the resulting ATC. Having standards in place that address the calculation of ATC components, data inputs, and modeling assumptions would help ensure non-discriminatory treatment by limiting a transmission provider's ability to use discretion to the disadvantage of competitors and the market.

117. As noted above, NERC does not have a formal definition of ETC. Without clear criteria for what should be included in a transmission provider's ETC, a transmission customer might not know whether ETC is being over- or underestimated. For example, a transmission provider could set aside more capacity for native load than is realistically expected to occur. This could happen if a transmission provider includes in ETC excess capacity for a load-serving entity (such as capacity to meet generation reserve requirements) but then also has a CBM component in its calculation of ATC that includes the same capacity. A transmission provider also could overestimate its ETC by double-counting the same transmission reservations in its ATC calculation. For example, this could happen if a transmission provider fails to replace a transmission reservation with the associated real-time schedule, and as a result does not release non-firm ATC. A consistent process for calculating ETC will limit the subjectivity of the transmission provider's decisions and provide a more uniform method for estimating ETC.

118. With respect to the modeling of a particular transaction, when information concerning the source is unknown, a transmission provider has the discretion to select

which generator(s) will be used as a source.¹¹⁹ There are no standards for how that modeling should be done and, consequently, a transmission provider could model a source using single or multiple generators by increasing (scaling up) their output. In general, modeling a transaction using multiple generators as a source is less conservative for the transmission system than modeling a transaction using a single generator as a source. Modeling a transaction using multiple generators as a source typically results in a higher ATC value. Conversely, when a transmission provider models a transaction using a single generator as a source, this can result in a lower ATC value depending on the location of the generator. Modeling of contingency outages used for calculating ATC is another area within the discretion of the transmission provider. Although the type of contingency, such as single contingency (n-1), is determined by governing reliability criteria,¹²⁰ the transmission provider determines which specific contingencies will be used for the ATC calculation. The common industry practice is to consider the loss of each transmission facility at voltage 100 kV and above. However, the lack of standards governing transfer analysis allows the transmission provider to use its discretion to

¹¹⁹ Transmission providers do not always know the generator used as a source of energy provided under contracts that qualify as designated resources; the only requirement is that the network customer have an executed contract that commits it to purchase noninterruptible power. See Wisconsin Public Power Inc. v. Wisconsin Public Service Corp., 84 FERC ¶ 61,120 at 61,650-51 (1998).

¹²⁰ Standard TPL-001-0, Table I. Transmission System Standards – Normal and Emergency Conditions, NERC Reliability Standards for the Bulk Electric Systems of North America (effective April 1, 2005).

monitor outages only of facilities at 230 kV and above, ignoring the limitations that may exist for the loss of the facilities at lower voltages, such as 115 kV or 138 kV.

Consequently, ATC values may vary substantially, with ATC being much higher when monitoring contingencies of facilities at 230 kV and above, and much lower while monitoring the loss of all facilities (voltage 100 kV and above).

119. Furthermore, in calculating ATC, transmission providers set aside a portion of transfer capability in the form of CBM and/or TRM to provide for adequate generation reserves and account for uncertainties or contingencies, respectively. Generally, CBM is the amount of firm transmission transfer capability held back by the transmission provider so that load-serving entities, whose loads are located on the transmission provider's system, can access remote generation reserve from interconnected systems in times of emergency generation deficiencies. Some believe it is necessary for transmission providers to set aside a portion of their TTC to ensure that their ties with other systems remain available for this purpose. There are no consistent industry-wide standards, however, for determining how much transfer capability should be set aside as CBM. There is also no common approach to whether the capacity is set aside for Native Load Customers, as defined in section 1.19 of the pro forma OATT, for retail load, or for all load-serving entities. The lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside has the potential to result in the transmission provider setting aside capacity that it might not otherwise need to, thus

increasing costs for native load customers and blocking other firm uses of the transmission system.¹²¹

120. Similarly, TRM is the amount of transmission transfer capability reserved by the transmission provider to ensure that the transmission network will be secure under a reasonable range of uncertainties in system conditions. Because TRM and CBM are both maintained in part for the loss of generators, there exists the possibility of double-counting reliability margins for the loss of the same generation.

121. Moreover, a transmission provider also can use more conservative inputs and assumptions for calculating ATC and performing system impact studies (that tend to minimize ATC) when it is assessing a long-term transmission service request, but use less conservative inputs and assumptions (that tend to maximize ATC) when it is performing system planning for retail native load. This creates the potential for undue discrimination where a transmission provider uses one set of data and assumptions to evaluate third party requests and another set of data and assumptions to plan its system to serve its own load.

¹²¹ The Commission has explained that the pro forma OATT requires both transmission customers and transmission providers using the transmission system to serve network load (including bundled retail native load) to designate their resources and loads so that the transmission customers and transmission providers would have no incentive to designate network resources above their needs and, in so doing, tie up valuable transmission capacity. Aquila Power Corp. v. Entergy Services, Inc., 90 FERC ¶ 61,260, reh'g denied, 92 FERC ¶ 61,064 (2000), reh'g denied, 101 FERC ¶ 61,328 (2002), aff'd sub nom. Entergy Services, Inc. v. FERC, 375 F.3d 1204 (D.C. Cir. 2004) (Aquila).

Data Exchange Among Transmission Providers

122. The lack of a consistent ATC calculation methodology combined with limited coordination between transmission providers can result not only in inefficiencies but unjust and unreasonable terms and conditions of service, especially for a customer seeking contiguous transmission service from multiple transmission providers. The ATC values posted by a transmission provider are often inaccurate for reasons beyond the control of the transmission provider. A transmission provider may post ATC values in good faith and attempt to provide transmission service based on these values only to discover later that the transfer capability that it thought was available no longer exists due to decisions made by other transmission providers that it did not know about at the time it made its calculations. Accurate ATC calculation requires reliable and timely information about such things as load, generation dispatch, facility outages, and transactions on neighboring systems. Transmission providers also may apply differing assumptions and criteria to ATC calculations, which may produce wide variations in posted ATC values for the same transmission paths. All of these considerations make it difficult for an individual transmission provider that operates one part of an interconnected grid to calculate ATC accurately.

123. This lack of communication and coordination between transmission providers of ATC data can also affect reliability. As discussed above, a transmission provider could grant transmission service without being aware of the real impact that service may have on an adjacent transmission provider's system, thus degrading the reliability of the

interconnected system. Inaccurate ATC values can cause overselling of transfer capability, which can lead to curtailments or transmission loading relief (TLR) actions to avoid exceeding thermal, voltage, and/or stability limits.

Transparency

124. As discussed, the lack of a consistent, industry-wide methodology for assessing ATC makes undue discrimination difficult to detect. This problem is further exacerbated by a lack of transparency surrounding the calculation methodology used by transmission providers. Although the Commission requires transmission providers to file their methodologies for calculating ATC in their tariffs, transmission providers often have responded by filing very general narrative descriptions of their calculation methodologies (often simply referring to the general NERC definition)¹²² without further specification of the mathematical algorithm, data inputs, and modeling assumptions used to perform the calculation.

125. Other than the description of the ATC methodology provided in transmission providers' tariffs, third parties often have limited access to information concerning the specific algorithms, data and assumptions used by transmission providers to evaluate their ATC, which makes it difficult to verify or challenge a transmission provider's ATC calculations. The Commission requires each transmission provider to calculate and post

¹²² See, e.g., the OATTs of Aquila, Inc., Southern, and Tucson Electric Power Company.

ATC and TTC values for each posted path.¹²³ Transmission providers also are required to make publicly available, on request, all data used to calculate ATC and TTC for any constrained path.¹²⁴ Additionally, transmission providers are required to make publicly available, on request, system planning studies or network impact studies performed for customers to determine network impacts. Furthermore, subsequent to Order Nos. 888 and 889, the Commission required each transmission provider to post (and update) the CBM value for each path for which it already posts ATC and TTC, as well as a narrative explanation of its CBM practices.¹²⁵

126. Yet, despite these requirements, third parties often are unable to gain access to sufficient information surrounding a transmission provider's ATC calculation methodology. As a preliminary matter, we note that while the OASIS requirements regarding the availability of information related to ATC and TTC calculations are still in effect, they have been affected by restrictions that have been placed upon the availability

¹²³ See 18 CFR 37.6 (b) (2005). A posted path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. Id. 37.6 (b)(1)(i).

¹²⁴ Id. 37.6 (b)(2)(ii). A constrained posted path is defined as any posted path having an ATC value less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours. Id. 37.6 (b)(1)(ii).

¹²⁵ Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999) (CBM Order).

of critical energy infrastructure information (CEII) in the interest of national security.¹²⁶

Therefore, system planning and network impact studies and models typically are no longer available on a transmission provider's OASIS. Furthermore, transmission customers are often unable to access other information such as load flow base cases and associated files. In sum, although existing Commission regulations are intended to provide a certain level of transparency, this transparency is undermined by a number of factors, including the absence of detailed descriptions of the data inputs, assumptions, and criteria used to determine the data included in ATC calculations, as well as the inability of customers to access certain of this data because of, among other reasons, security concerns.

Recent Industry Efforts to Improve the Consistency and Transparency of ATC Calculations

127. The industry recently has taken some steps to address the lack of consistency and transparency in the way ATC is calculated. NERC formed a Long-Term AFC/ATC Task Force to review NERC's standards on ATC, which issued a final report in 2005 (NERC Report)¹²⁷ that made recommendations for greater consistency and greater clarity in the

¹²⁶ See Critical Energy Infrastructure Information, Order No. 630, 68 FR 9857 (Mar. 3, 2003), FERC Stats. & Regs. ¶ 31,140 (2003), order on reh'g, Order No. 630-A, 68 FR 46456 (Aug. 6, 2003), FERC Stats. & Regs. ¶ 31,147 (2003), order on clarification, Order No. 662, 70 FR 37031 (Jun. 28, 2005), FERC Stats. & Regs. ¶ 31,189 (2005); see also 18 CFR 388.113 (2005).

¹²⁷ See supra note 115.

calculation of ATC. The task force also recommended greater communication and coordination of ATC information to ensure that neighboring entities exchange relevant information. Based on the recommendations in the NERC Report, NERC has two Standards Authorization Request (SAR) proceedings underway to revise the standards on ATC. The first SAR proceeding proposes changes to the existing standards on ATC to, among other things, further establish consistency (on a regional basis) in the calculation of ATC and to increase the clarity of each transmission provider's ATC calculation methodology. The second SAR proceeding proposes certain changes to NERC's existing standards on the ATC components of CBM and TRM. This proceeding also calls for greater regional consistency and transparency in how CBM and TRM are treated in transmission providers' ATC calculations. Also, based on the recommendations in the NERC Report, the North American Energy Standards Board (NAESB) has a proceeding underway to develop business practice standards to enhance the processing of transmission service requests, which use TTC, ATC and/or AFC.

128. Following the release of the NERC Report, the Commission issued the ATC NOI¹²⁸ seeking comments on the contents of the NERC Report. More specifically, the Commission sought comments on the NERC Report's recommendations on areas in which CBM and TRM could be more specific and whether these recommendations go far enough in promoting a common CBM and TRM methodology within each region. The

¹²⁸ Supra note 9.

Commission also sought comments on the definitions of ATC, AFC, CBM and TRM.

The Commission also solicited comments on the advisability of revising and standardizing ATC, AFC, TRM and CBM values. In addition, the Commission sought comments on the advisability of developing interconnection-wide standards for the Eastern Interconnection and WECC. Finally, the Commission asked for comments on the most expeditious way to obtain industry-wide standards for ATC calculations.

129. Furthermore, in the NOI, the Commission sought comments on whether undue discrimination is most likely to occur in areas such as ATC calculation where the transmission provider retains discretion as to how to implement a particular tariff provision.

Comments

Comments on Consistency

130. Many commenters express general support for some level of increased consistency in ATC calculations.¹²⁹ Some commenters urge the Commission to develop a consistent, industry-wide methodology for calculating ATC.¹³⁰ Constellation asserts that although transmission providers need to be innovative and flexible in many respects, a requirement

¹²⁹ E.g., Alcoa, Ameren, AWEA, Calpine, Constellation, Cottonwood ATC NOI Comment, ELCON, Exelon, FTC ATC NOI Comment, Midwest ISO ATC NOI Comment, Midwest SATS, New York Commission ATC NOI Comment, North Carolina Commission, Occidental, South Carolina E&G, TAPS, and TransAlta.

¹³⁰ E.g., Alcoa, AWEA, Constellation, Exelon, Occidental, and Renewable Energy.

that all transmission providers use the same methodology to determine ATC would not only remedy the lack of clarity that surrounds these calculations and reservations, but would provide regulatory certainty and assist transmission customers in predicting the outcome of transmission service requests. This, in turn, Constellation suggests, would expand the commercial opportunities for transmission customers. According to Alcoa, AWEA and Renewable Energy, the industry-wide methodology should be a flow-based methodology, rather than a contract path methodology because they believe that a flow-based analysis provides a more realistic view of actual system usage and results in a more accurate assessment of ATC. Exelon further suggests that this uniform methodology should also apply to all transmission providers, including RTOs.

131. Other commenters argue against a one-size-fits-all approach, but rather express a preference for greater uniformity at a regional level to recognize regional differences.¹³¹ These commenters suggest that due to differences in transmission systems or regions, it may not be practical or possible to standardize the ATC calculation methodology on an industry-wide basis. For example, Powerex cautions that nationwide standardization may not take into account the unique characteristics of particular systems or regions, such as the differences attributable to the West's contract-path model and the East's flow-based

¹³¹ E.g., Alberta Intervenors, APPA, Bonneville, International Transmission, ISO/RTO Council, LDWP, MidAmerican, Nevada Companies, Powerex, Progress Energy, Public Generating Pool, Public Power Council, Salt River, Santa Clara, Snohomish, Tacoma Power, TANC, and TDU Systems.

model, as well as differences attributable to the primarily hydro-based systems in the Pacific Northwest.¹³² Similarly, TANC argues that flowgate terminology and application in ATC calculation should not be required in the West because it does not adequately represent the nature of the many transmission constraints in the West. Other commenters caution that too much uniformity of the ATC calculation methodology could have an adverse effect on grid reliability.¹³³ In addition, some commenters urge the Commission not to adopt an ATC methodology that is so prescriptive that it inhibits new or better practices or imposes a wholesale revision of accepted market designs and processes that are working within established markets.¹³⁴

132. Several commenters argue against any efforts to further standardize ATC calculations.¹³⁵ In its comments filed in the ATC NOI proceeding, LDWP asserts that the alleged problems with ATC are overstated. Moreover, it argues, the benefits of squeezing additional ATC from existing systems have not been established given that transmission customers can already request any capacity they need regardless of the posted ATC and transmission providers are required to make a good-faith effort to

¹³² Accord LDWP ATC NOI Comment, Public Power Council, Salt River, Snohomish, Tacoma, and TANC.

¹³³ E.g., NERC ATC NOI Comment, Public Power Council, and TVA.

¹³⁴ E.g., ISO/RTO ATC NOI Comment and Powerex.

¹³⁵ E.g., Cinergy, EEI, LG&E, LDWP ATC NOI Comment, National Grid, PPL, Public Generating Pool, San Diego G&E, Southern, TVA, and Xcel.

evaluate each request. Several commenters argue that the circumstances of individual transmission customers vary and often ATC calculations rely on the individual transmission provider's knowledge of its facilities and system conditions.¹³⁶ For example, Southern contends that too many factors go into the calculation of ATC to make the adoption of a static set of standards feasible. In fact, Southern and EEI maintain, standardization of ATC calculations is inconsistent with maintaining reliability because the circumstances of transmission providers vary significantly, and they must operate their systems based on their specific circumstances. In addition, LG&E maintains that standardizing ATC will not necessarily eliminate the need for TLR procedures to deal with load forecast errors and unplanned generation and transmission outages. Furthermore, some commenters argue that increased uniformity could impose significant costs upon utilities.¹³⁷

133. Some commenters urge the Commission to increase the consistency of the elements of the ATC calculation, such as the kind of data inputs that transmission providers consider when evaluating ATC – including load levels, generator outage information, transmission outage information and generation dispatch information.¹³⁸

Exelon also urges the Commission to establish the assumptions that transmission

¹³⁶ E.g., Southern and TVA.

¹³⁷ E.g., International Transmission and LG&E.

¹³⁸ E.g., Exelon and TDU Systems.

providers use in their ATC methodologies – such as how transmission reservations are accounted for and which reservations to model. Exelon also cites an example of modeling transaction counterflows, noting that uniform rules for data inputs are needed to ensure that transaction counterflows are modeled identically in both the planning and ATC/AFC calculation processes. In addition, commenters urge the Commission to establish the procedures for determining ATC (and its components) and to require a transmission provider to show that it has properly followed all required procedures.¹³⁹ Among other things, commenters suggest that the Commission should establish how frequently ATC is calculated, how frequently inputs are updated, require transmission providers to determine AFC instead of ATC, and require transmission providers to recognize all third-party flowgates that are requested to be monitored. In addition, several commenters state that the Commission should require that the methodology and inputs for ATC calculations be consistent with the transmission provider’s planning or operating criteria.¹⁴⁰

134. Several commenters urge the Commission to allow the industry, working through NERC and NAESB, to complete efforts already underway to further increase consistency

¹³⁹ E.g., Ameren and Exelon.

¹⁴⁰ E.g., Exelon, ISO/RTO ATC NOI Comment, MISO, and NERC.

of ATC (and its components), as well as certain related business practices.¹⁴¹ However, many of these commenters urge the Commission to give the industry, working through these organizations, specific guidance on what issues to decide and the parameters for the discussions.¹⁴² Furthermore, commenters state that the Commission should establish a date certain for completion of these industry efforts,¹⁴³ and should also take an active role in the process.¹⁴⁴

135. Other commenters suggest that the Commission should require that an independent entity develop and/or monitor a transmission provider's ATC methodology and its ATC calculations.¹⁴⁵ For example, Constellation states that it does not believe that the solution is to prohibit the transmission provider entirely from exercising its discretion, but instead to require transmission providers to retain an independent entity that can perform certain functions on a consistent, unbiased basis. In addition, the

¹⁴¹ E.g., Ameren, APPA ATC NOI Comment, Duke, EEI, Exelon, International Transmission Company ATC NOI Comment, ISO/RTO Council ATC NOI Comment, KCP&L, MidAmerican ATC NOI Comment, MISO ATC NOI Comment, Progress Energy, Southern, TAPS, TDU Systems, TransAlta, and WestConnect ATC NOI Comment.

¹⁴² E.g., APPA ATC NOI Comment and International Transmission ATC NOI Comments.

¹⁴³ E.g., Duke and Exelon.

¹⁴⁴ E.g., APPA ATC NOI Comment, TAPS, and TransAlta.

¹⁴⁵ E.g., Arkansas Commission, Calpine, Constellation, EPSA, New York Commission, Occidental, and TDU Systems.

Arkansas Commission asserts that section 1281 of EAct 2005¹⁴⁶ gives the Commission the authority to require the use of an independent coordinator of transmission to provide independent and verifiable transparency over critical Order No. 888 functions, such as ATC calculations.

136. Several commenters specifically address the lack of consistency in the industry on the definition and use of CBM and TRM. For example, TAPS notes that NERC does not require any transmission provider to reserve CBM. In addition, TAPS states, even in those regions that use CBM, there is often no regional methodology; it is up to the vertically integrated transmission provider to determine whether it wants to reserve CBM at all and at which interfaces, with no effective review of that determination. TAPS also states that TRM should be clearly defined and, if truly required for reliability, then all transmission providers should reserve it. According to TAPS, the Commission should define TRM in a manner that leaves no discretion as to whether, where, and how much capacity to set aside. EPISA also notes that there is a disconnect between the planning and expansion processes and the assumptions transmission providers use to calculate CBM and TRM.

¹⁴⁶ EAct 2005 sec. 1281(to be codified at section 220 of the FPA ,16 U.S.C. 824t), which concerns electricity market transparency rules.

137. TANC states that the Commission should closely examine the necessity of CBM in ATC calculations. Bonneville argues that there should only be one commercial margin instead of multiple margins (TRM, CBM, and others).

Comments on Data Exchange among Transmission Providers

138. Several commenters argue that the Commission should establish standards for resolving seams issues between transmission providers where each transmission provider uses a different methodology for calculating ATC.¹⁴⁷ Constellation and BC Transmission assert that when different transmission providers have different methods for determining ATC, this can lead to inefficiencies, including market confusion, lost sales/purchase opportunities, and unnecessary curtailments.

139. Commenters identify various elements of the ATC calculation methodology that they argue should be more consistent. For example, BC Transmission states that some of the elements that are calculated differently at the seams include the level of TRM, the level of CBM, the approach regarding the sale (or not) of TRM as non-firm capacity, assumptions regarding controlling interchange and assumptions regarding operating conditions. Similarly, MidAmerican in its response to the ATC NOI suggests that greater coordination is needed on partial path review, policies for decrementing AFC and redispatch policies. For example, MidAmerican references problems associated with

¹⁴⁷ E.g., BC Transmission, Constellation, Exelon, NY Transmission, Renewable Energy, and TDU Systems.

coordination between transmission providers on partial path treatment. Specifically, when transmission service involves a path across multiple systems, a given flowgate may be evaluated several times by various providers on the transmission path. Because of a lack of coordination between these providers, AFC on the flowgate may be decremented multiple times for the same transmission service request, and service may be denied even when the true available capacity on the flowgate is sufficient to allow the request to be granted. Exelon also states that certain data inputs must be coordinated across all transmission providers in an interconnection including load levels, transmission outages, generation outages and generation dispatch. In addition, Exelon states, the Commission should establish how transmission providers account for transmission reservations in an ATC/AFC calculation.

140. Moreover, NY Commission suggests that this problem goes beyond the non-independent transmission providers. According to NY Commission, in order for RTOs to properly determine tie flow limits, they need access to certain information from the control region on the other side such as load levels and distributions, generator dynamic capability and expected outputs, phase shifter positions and standard contingencies required by that control area. In addition, NY Commission states, these inputs need to be updated daily.

141. Finally, Alcoa states that the potential for underestimating ATC is likely another consequence of the fundamental conflict between the contract path model and the electricity path model of contracting for electric energy. According to Alcoa, outside of

ISO/RTO systems, utilities may not have enough data available to compute ATC, since they may not be able to accurately complete all relevant parallel path transactions.

Comments on Transparency

142. Commenters are overwhelmingly in favor of greater transparency in the ATC calculation methodology to provide more assurance that a transmission provider is not performing its ATC calculations in an inconsistent or unduly discriminatory manner.¹⁴⁸ EEI suggests that transmission providers could make their base case load flow studies on which they base their calculation of ATC available to transmission customers, subject to security and confidentiality protections. Other commenters state that greater transparency could be achieved through the imposition of additional posting requirements on OASIS.¹⁴⁹ These commenters argue that the Commission should require transmission providers to post their discrete methodologies and algorithms for evaluating ATC, as well as their transmission modeling information and their various assumptions. Commenters further suggest that transmission providers should be required to provide information

¹⁴⁸ E.g., Alcoa, Ameren, APPA, Calpine, CEOB, Cinergy, Constellation, Cottonwood, Duke, EEI, ELCON, HQ Energy, LDWP, MidAmerican, Midwest ISO, Midwest SATs, Powerex, PPL, Progress Energy, Public Generating Pool, Public Power Council, Salt River, Southern, TANC, TAPS, TDU Systems, TransAlta, and TVA.

¹⁴⁹ E.g., Calpine and PPL.

regarding planned outages, and to ensure consistent treatment of outage information between control areas.¹⁵⁰

143. In its reply comments, Southern acknowledges that greater transparency would reduce concerns of undue discrimination, but cautions the Commission against imposing unnecessary and duplicative posting requirements and notes that much of the information that commenters have asked the Commission to make transparent is in fact already publicly available through a variety of sources.

144. In addition, some commenters urge the Commission to impose meaningful reporting requirements.¹⁵¹ In this regard, Constellation asserts that the Commission should modify the pro forma OATT to require that transmission providers post systematic, timely and accurate reporting of certain service metrics such as transaction requests approved, rejected, confirmed, and curtailed. Similarly, Cottonwood states that transmission providers should be required to provide information detailing why a particular transmission request was denied and whether there are other available alternatives. In addition, several commenters argue that transmission providers also should be required to post their relevant business practices, operating standards, protocols and internal guidelines that affect transmission service.¹⁵² TDU Systems also urge the

¹⁵⁰ E.g., H.Q. Energy and Powerex.

¹⁵¹ E.g., Constellation, Cottonwood, and TDU Systems.

¹⁵² E.g., Powerex and TransAlta.

Commission to require transmission providers to explain why transactions are allowed to flow even when the posted ATC value was zero.

145. EPSA argues that capacity is unnecessarily held from the market when transmission providers reserve excessive amounts for their native load and when they fail to make capacity available through redispatch. EPSA states, however, that there is no way of knowing whether there is a hoarding problem because there is no requirement to post the necessary real time information on transmission utilization, and recommends a requirement to post such information. Powerex contends there is an incentive for transmission providers to hoard because grandfathered or other firm rights held by the transmission provider to serve native load are subsequently used for wholesale marketing purposes. It further states, however, that evidence of anticompetitive practices is difficult to obtain because of a lack of transparency. Powerex supports increased requirements for both uniform and transparent ATC calculation.

146. Several commenters urge the Commission to establish compliance review procedures and impose sanctions for violations to ensure that transmission providers are accountable for ensuring that their ATC calculations are correct.¹⁵³ In its response to the ATC NOI, Cottonwood states that the Commission should develop specific tests (benchmarks) to monitor transmission providers' performance. In addition, HQ Energy

¹⁵³ E.g., Cottonwood ATC NOI Comment, ELCON, HQ Energy, NRECA, Occidental, and Powerex.

states that the Commission should conduct periodic reviews of whether non-independent transmission providers have properly calculated and allocated ATC. ELCON states that the Commission should place the burden of proof to depart from its ATC methodology on the transmission provider and include specific penalties in the tariff for transmission providers that are found to be in violation.

147. HQ Energy and Powerex also state that the Commission should require transmission providers to ensure that staff is available at all times to respond to customer inquiries regarding real-time transactions.

Discussion

148. We propose to address the potential for remaining undue discrimination in the determination of ATC by requiring industry-wide consistency and transparency of certain definitions, data, modeling assumptions and components of ATC. We propose to provide general guidance regarding the aspects of ATC calculation that we believe should be more consistent and direct public utilities, working through NERC and NAESB, to use our guidance to revise the relevant standards and business practices. In addition, we propose to require increased detail in the pro forma OATT regarding the method of calculating ATC and to amend our OASIS regulations to require increased transparency.

149. Though NERC and NAESB currently are working on certain proposals to address the problems we have identified,¹⁵⁴ we are concerned that without guidance, direction and a firm deadline, these industry developments may not succeed due to other conflicting priorities. We believe that the existing NERC and NAESB processes are well-suited to achieving greater consistency in ATC calculations. It is our expectation that NERC and NAESB will expand on the work they have already undertaken to achieve the goals we propose to set out for them.

150. We propose to take this action pursuant to our obligation under FPA section 206 to remedy undue discrimination in the provision of transmission service. Transmission providers in general enjoy substantial discretion in establishing and interpreting the specific algorithms, data, and assumptions needed to assess ATC. Though we do not believe it is possible or necessary to entirely eliminate discretion, unchecked discretion affords a transmission provider the ability and opportunity to discriminate in its favor (and its affiliate's favor) against third parties in how it calculates and allocates ATC and, therefore, may be unjust, unreasonable, unduly discriminatory and preferential.

Transmission providers have an incentive to understate ATC on transmission paths that

¹⁵⁴ We understand that two NERC standard authorization requests related to ATC/TTC/AFC and CBM/TRM were approved earlier this year, and that drafting of the standards' revision is underway. We further understand that NAESB has a concurrent drafting effort underway for associated business practices that will follow a coordinated path with the NERC process. See <http://www.nerc.com/~filez/standards/MOD-V0-Revision.html>.

would be valuable to power sellers that are competitors to the transmission providers' own (or their affiliates') power sales. Where transmission congestion exists, the methodology for calculating ATC will effectively determine whether competitors have access to the transmission grid, and the lack of any consistent methodology for calculating ATC gives transmission providers excessive discretion in making this determination.

1. The lack of consistency and detail in the determination of ATC can facilitate undue discrimination in a variety of ways. Transmission providers may use generation **dispatch assumptions** that result in limited capacity being available to merchant generators. They also may use different **inputs and assumptions** for purposes of calculating ATC **for third parties than they do for system planning for retail native load.** As noted above, a transmission provider could reduce a facility rating or model certain facilities as out of service, which would have the effect of underestimating TTC. In determining ETC, transmission providers have discretion to determine the capacity needed and set aside for native load usage. Each of these exercises of discretion has a significant effect on ATC.

152. The **lack of transparency** into how a transmission provider calculates and allocates its ATC (including all assumptions and data inputs) **makes it difficult to detect discriminatory behavior.** This lack of transparency frustrates and increases the costs of compliance and enforcement efforts. Many transmission providers have urged the

Commission to provide greater clarity in the rules for OATT service,¹⁵⁵ particularly given the threat of the Commission’s new civil penalty authority.

153. In addition to our preliminary finding that the **lack of consistent**, industry-wide ATC calculation standards is unjust and unreasonable under FPA section 206, we believe that it **poses a threat to the reliable operation** of the bulk-power system. A transmission provider needs to know how much electricity its system can carry. The lack of a consistent, industry-wide methodology for evaluating ATC and the lack of data sharing among transmission providers often leads to problems in determining the appropriate ATC value. Despite a transmission provider’s good faith attempt to calculate and post accurate ATC levels, it can find that transmission that it thought was available on its system no longer exists because it was unaware of decisions by other transmission providers. This, in turn, can threaten the reliable operation of the interconnected transmission system.¹⁵⁶

¹⁵⁵ E.g., Ameren, APPA ATC NOI Comments, Duke, EEI, Exelon, International Transmission Company ATC NOI Comments, ISO/RTO Council ATC NOI Comments, KCP&L, MidAmerican ATC NOI Comments, MISO ATC NOI Comments, Progress Energy, Southern, TAPS, TDU Systems, TransAlta, and WestConnect ATC NOI Comments.

¹⁵⁶ According to NERC, “the lack of standardization and more significantly, limited coordination can negatively impact both the market, through the need for a large number of [TLR] actions (or curtailments in WECC) and, on occasion, reliability when even the use of TLRs provides insufficient relief on some critical interfaces.” See NERC Report at 1.

154. As a result of reliability effects of inconsistent ATC calculations, our proposal for greater consistency and transparency also is supported by our new authority under section 215 of the FPA, which gives the Commission jurisdiction to certify an Electric Reliability Organization (ERO) and to approve reliability standards that are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission also has authority to order the ERO to submit a reliability standard that the Commission considers appropriate to implement FPA section 215.¹⁵⁷ On April 4, 2006, NERC submitted an application to be certified as the ERO, as well as proposed reliability standards.¹⁵⁸ In this NOPR, we direct our guidance to public utilities and recommend that they implement our direction by working with NERC. However, this is not intended to prejudge the outcome of the ERO proceeding. Though the Commission will act independently on the reliability standards proposed by NERC in Docket No. RM06-16-000, we believe it is prudent to provide our guidance now on NERC's reliability standards related to ATC by providing specific direction on what should be more consistent and a timeframe for completion of NERC's efforts.¹⁵⁹ As we indicated above, the lack of consistency, data exchange and transparency in ATC calculations not only can

¹⁵⁷ Section 215(d)(5).

¹⁵⁸ See Docket Nos. RR06-1-000 and RM06-16-000.

¹⁵⁹ In this NOPR, we direct our guidance to NERC, though the reliability standards relating to ATC ultimately will be adopted by the ERO.

increase the opportunities for undue discrimination but also can threaten reliability. We therefore believe that Commission action pursuant to FPA section 215 may be appropriate on reliability standards related to ATC calculation. Any action on these reliability standards that is taken in Docket No. RM06-16-000 (the ERO standards rulemaking) will be coordinated and consistent with our determinations regarding ATC calculation in this proceeding.¹⁶⁰

Consistency

155. The Commission proposes to require public utilities, working through NERC, to develop the standards we set forth below within 6 months of the final rule in this proceeding. Consistent with NERC's existing efforts, we propose to require the development of standards for: (1) ATC/AFC, TTC/Total Flowgate Capacity (TFC), ETC, CBM, and TRM calculation methodologies, (2) data inputs, (3) modeling assumptions, (4) ATC calculation frequency, and (5) data exchange and coordination processes. We further propose to require public utilities, working through NAESB, to work with NERC to identify the appropriate business practices to complement the standards developed by NERC. We discuss below each of the elements for which we propose to require more consistency. We seek comment on these elements of the ATC

¹⁶⁰ We note that Commission staff recently released a preliminary assessment of the proposed ATC-related reliability standards, stating that they “may result in unnecessary regional variations not justified by technical differences and inconsistent applications.” Staff Preliminary Assessment of the North American Reliability Council's Proposed Mandatory Reliability Standards at 80 (May 11, 2006).

calculation and, in particular, whether certain elements are more susceptible to further consistency than others and whether certain elements should be prioritized over others because they represent the source of most disputes between transmission providers and customers. We recognize the need to focus on those elements of the ATC calculation that are most susceptible to further consistency and most important in terms of eliminating opportunities for undue discrimination.

156. The Commission recognizes that transmission providers use several basic types of ATC calculation methodologies (with various permutations), and does not believe that a single ATC calculation methodology must be applied by all transmission providers.¹⁶¹

However, we agree with commenters who argue that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. Accordingly, we propose to achieve greater consistency in ATC calculations by directing the development of

consistent definitions of the components of ATC, as well as consistent data inputs, data

exchange and coordination protocols, and modeling assumptions, as discussed further

below. We believe that this level of consistency will go a long way toward producing

¹⁶¹ For example, there are two primary ATC calculation methodologies: the contract path approach and the flowgate approach. See generally P 115. However, the ATC values that result from application of either method should largely be the same if consistent data inputs and modeling assumptions are used.

more coherent and uniform determinations of ATC across a region, thereby helping to eliminate the potential for undue discrimination.¹⁶²

157. We propose to direct public utilities, working through NERC, to develop consistent practices for TTC/TFC calculation methodologies. We recognize that the NERC reliability regions have historically calculated transfer capability using different approaches.¹⁶³ However, we expect that guidelines can be developed for the calculation of transfer capability that use a common approach to model power transfers. In addition, we believe that the criteria used for identifying flowgates and determining TTC/TFC can be more consistent.

158. The Commission believes that the lack of consistency of ETC permits too much discretion in determining how much capacity a transmission provider sets aside for native load, including its network customers. We believe that the development of an industry-wide methodology can limit this discretion. Therefore, we propose to require the development of a consistent methodology for determining the capacity needed and set aside for native load usage. In addition, we propose that accounting for transmission reservations in an ATC/AFC calculation also should be more consistent. Presently, there

¹⁶² As discussed further below, for consistency to be fully effective, it should be coupled with increased transparency. As such, we also propose greater transparency below.

¹⁶³ One approach models power transfers by scaling up/down the load, a second approach scales generation up/down, and yet another approach uses a combination of changes in load and generation.

are two main methods in use. One method models all “appropriate reservations”¹⁶⁴ in the power flow base case model. The other method models only those reservations that are expected to be actually scheduled and accounts for others by decrementing flowgate AFC. It is important for consistency to use the same calculation technique when modeling these types of reservations. Therefore, we propose that public utilities, working through NERC, establish and specifically identify which reservations they use in determining ETC.

159. The Commission has previously addressed the lack of a consistent industry-wide methodology for determining CBM. Following a two-day technical conference, the Commission held in the CBM Order¹⁶⁵ that transmission providers continue to wield significant latitude in interpreting how CBM is determined. The Commission directed that the CBM set-aside be more transparent, more accurate, and more widely available.¹⁶⁶ We remain concerned, however, that transmission providers have preferential access to the interface capacity that is set aside. This interface capacity is paid for by all transmission customers whether or not they receive a benefit from the set-aside. In


¹⁶⁴ “Appropriate reservations” takes into account the time frame (e.g., yearly, monthly) and ATC product (e.g., firm, non-firm) being calculated.

¹⁶⁵ Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999) (CBM Order).

¹⁶⁶ CBM Order at 61,237-38.

general, we believe that the latitude associated with CBM undermines the certainty and transparency that is needed for non-discriminatory, open-access transmission service.

160. The current pro forma OATT offers two means of reserving transfer capability, either of which implicitly provides some financial discipline to overreservations. The first is the requirement to designate a network resource on the other side of the interface and assume the associated financial responsibility of either owning the resource or executing a firm power purchase agreement. The other is to contract for firm point-to-point service on the interface, which requires the payment of a point-to-point reservation charge. In either case there is a disincentive to reserving transfer capability simply to prevent someone else from using it on a firm basis. With these processes in mind, the Commission has identified three possible options to provide the necessary certainty, transparency, and financial discipline necessary to remedy the potential for undue discrimination associated with inappropriate ATC set-asides for CBM. These options need not be mutually exclusive.

161. One option is to require that clear standards be developed for  the CBM value should be determined and allocated across transmission paths, and for which customers CBM should be used.¹⁶⁷ Consistent with the standards development process that is already in progress, we propose that these standards specify how CBM should be

¹⁶⁷ NERC has already contemplated developing a standard to address CBM issues. See <http://www.nerc.com/~filez/standards/MOD-V0-Revision.html>.

reserved to allow any load-serving entity to meet generation reliability criteria on a nondiscriminatory basis. In addition, we propose that NERC specify emergency generation deficiency conditions during which a load-serving entity will be allowed to use the transfer capability reserved as CBM. We believe that CBM should be reserved only when there is insufficient local generation capacity to meet generation reliability standards, and it should always have a zero value in the calculation of non-firm ATC.

162. Another approach may be to develop a specific charge for setting aside ATC for CBM. This approach would treat CBM as a service that would be available to customers serving load within the transmission provider's service area. To do this, the Commission would propose that an entity for which transfer capability has been set aside to meet generation reliability criteria be charged a separate rate for this service. We seek comment on this proposal to charge a separate rate, as well as comment on the potential impacts on overall rates and revenues. We also seek comment on whether there are credible situations in which the proposal would not be feasible. Commenters are encouraged to provide specific examples.


163. A third option may be to eliminate CBM and replace it with specific transfer capability reservations associated with designated network resources. In several cases, the Commission addressed instances when transmission providers had taken advantage of their ability to preserve interface capability to serve their own load while limiting the ability of competing suppliers to access customers on their systems. In these orders, the Commission position was that if a utility wanted to use firm transmission capacity on an

interface to serve its native load, it was required to designate a network resource associated with that capacity on the other side of the interface pursuant to the requirements of the pro forma OATT.¹⁶⁸ Specifically, the Commission stated that the pro forma OATT requires the transmission provider to designate all network resources, including those acquired for the purpose of meeting generation reserves, in the same manner as network customers do.¹⁶⁹ The retention of this obligation would require the transmission provider to replace any existing set-aside of firm transfer capability as CBM with reservations for specific designated resources. We seek comment on the reasonableness of eliminating CBM and any impacts on the reliable operation of the transmission system. Commenters are encouraged to provide specific examples of transmission providers that currently do not use CBM and, alternatively, conditions under which CBM must be used. We also ask for comments on how eliminating CBM would affect the ability of load-serving entities to meet existing generation reliability adequacy requirements.

164. The Commission proposes that public utilities, working through NERC, **develop clear standards for how TRM is determined, allocated across transmission paths, and**

¹⁶⁸ See Aquila *supra* note 121; see also Morgan Stanley Capital Group v. Illinois Power Co., 83 FERC ¶ 61,204, clarified, 83 FERC ¶ 61,299 (1998), order on reh'g, 93 FERC ¶ 61,081 (2000).

¹⁶⁹ Wisconsin Public Power Inc. SYSTEM v. Wisconsin Public Service Corp., 83 FERC ¶ 61,198 at 61,857-58 (1998).

 used. In addition, we propose to require that the standards ensure that there will be no contingency double-counting when calculating TRM, TTC and CBM. We also propose that the standards developed should specify the uncertainties that are accounted for in TRM and the methods used to determine their impacts on TRM values. The Commission proposes that TRM can be used to accommodate uncertainties such as: (1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC forums.

165. The Commission acknowledges that accurate data and system models are essential to accurately simulate the performance of the electric system when calculating ATC. The data and models used by the transmission provider should be consistent, to the maximum extent practicable, with the data and models used for the planning, operation, and expansion of the transmission system. While NERC's current ATC-related standards (MOD-001- MOD-009) require that steady state and dynamic data be submitted and that steady state and dynamic system models be prepared, there is no requirement to periodically benchmark these models and appropriately modify them against actual

em events.¹⁷⁰ Therefore, the Commission proposes that public utilities, working through NERC, modify the ATC-related standards to incorporate a requirement for the periodic review and modification of these models (including load flow base cases, short circuit data, transient and dynamic stability simulation data, contingency,¹⁷¹ subsystem and monitoring files, and production cost models), in order to ensure that they are up to date.

166. Modeling assumptions are a crucial element in the calculation of ATC. The Commission proposes that public utilities, working through NERC, develop consistent assumptions for use in ATC determinations. The Commission proposes that the assumptions used in the calculation of ATC be made consistent among transmission providers, to the maximum extent practicable. In general, the Commission believes that the assumptions used in the determination of ATC should be consistent with those used when planning the operation and expansion of the transmission system. This is necessary to remedy the potential for undue discrimination between the manner in which a transmission provider plans and operates its system to serve native load and the manner in which it calculates ATC for service to third parties. Consequently, the models for

¹⁷⁰ See U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, Recommendation Number 24 (April 2004). See <https://reports.energy.gov/>.

¹⁷¹ Contingency files should contain information on special protection schemes and remedial action plans.

short- and long-term ATC calculation should be developed using consistent assumptions regarding the load level, generation dispatch, transmission and generation facilities maintenance schedules, contingency outages and topology as those used in the planning for operation and expansion. In addition, the long-term ATC models should rely to the maximum extent practicable upon the same assumptions regarding new transmission and generation facilities additions and retirements as those used in the planning for expansion.

167. More specifically, the Commission proposes to direct public utilities, working through NERC, to establish consistent assumptions that are related to the modeling of:

(1) representative load levels, (2) generation dispatch, (3) transmission reservations and (4) counterflows, in addition to any other modeling assumptions identified by NERC.

Regarding the assumptions used for load level modeling in the ATC calculation, the Commission proposes to require all transmission providers to have a consistent approach to modeling of load levels. With respect to the base generation dispatch, we propose that public utilities, working through NERC, establish a method for determining which generators should be modeled in service, including guidance on how independent generation should be considered. With respect to modeling of particular transactions, the Commission believes that a consistent approach is needed on how to simulate power flows from points of receipt to points of delivery when sources are unknown.

Accounting for transmission reservations in an ATC/AFC calculation also should be

consistent.¹⁷² We note that the purpose of more consistent modeling assumptions is to eliminate discretion and the potential for undue discrimination. This proposal is not intended to change the manner in which native load customers are served. We seek comment on whether (and, if so, how) this proposal would affect service to native load customers.

168. The Commission also supports the development of clear standards on how often ATC/AFC and its individual components are calculated and updated. The Commission proposes that public utilities, working through NERC and NAESB, develop standards requiring that the calculation be performed on a consistent time interval among transmission providers and in a manner that closely reflects the actual topology of the system concerning generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. The Commission also supports uniform updating of ATC values and components by adjacent control areas.

169. The Commission believes that significant improvements in the communication, coordination, and exchange of data across all transmission providers in an interconnection are needed to produce accurate determinations of ATC. Therefore, we propose that public utilities, working through NERC, develop consistent protocols that

¹⁷² Currently, one method models all appropriate reservations in the power flow base case model, when another models only those reservations that are expected to be scheduled, and accounts for others by decrementing flowgate AFC.

Should enable and require the exchange of data among transmission providers. We propose that the following data, at a minimum, should be exchanged among transmission providers for purposes of ATC modeling: (1) load levels, (2) transmission planned and contingency outages, (3) generation planned and contingency outages, (4) base generation dispatch, (5) existing transmission reservations, including counterflows, (6) ATC calculation frequency, and (7) source / sink modeling identification. In addition, NERC may identify other data needs through the standards development process. We seek comment as to how much data sharing is workable; whether there are additional data that should be provided; whether access to such data should be limited to transmission providers; and if there are existing forums by which these or similar data are already shared.

170. In order to facilitate the process for achieving consistency in ATC calculations we have proposed in this NOPR, the Commission directs Staff to hold a technical conference. The technical conference will be transcribed to provide the Commission and NERC a record of the comments received at the conference. The Commission will provide further guidance regarding the date of the technical conference and the topics it intends to address at the technical conference in a subsequent notice.

Transparency


Pro forma OATT


171. Though the Commission's requirement that a transmission provider describe its ATC calculation methodology in its OATT has not changed, that requirement has been

interpreted in various ways. Some transmission providers post a detailed explanation of how they calculate ATC, while other transmission providers post very general descriptions that fail to offer sufficient detail for third parties to understand how ATC has been derived. The Commission is concerned that the lack of transparency in some of the descriptions provided by transmission providers gives these transmission providers too much discretion to change ATC practices without sufficient oversight and review. The Commission also is concerned that this lack of transparency could allow transmission providers to unduly discriminate against their competitors when allocating transmission service. We agree with commenters that greater transparency is needed into how transmission providers calculate and allocate ATC. Accordingly, in order to ensure that transmission service is provided in a nondiscriminatory manner, we propose to require transmission providers to take certain measures to make their ATC calculation process more transparent. We believe that these proposed changes will give transmission customers access to sufficient information to be able to examine the integrity of the process. Moreover, our proposal for greater consistency in the way ATC is calculated should aid in transparency because there will be far fewer differences in the way individual transmission providers calculate ATC. This will make it less difficult to determine whether ATC is being calculated in an unduly discriminatory manner.

172. Specifically, we propose to require transmission providers to include, at a minimum, in Attachment C of their OATT, the following information concerning their ATC calculation methodology (including the calculation of AFC, if applicable). First, we

propose to require transmission providers to state their specific mathematical algorithm used to calculate their firm and non-firm ATC (and AFC, if applicable) for their scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and their planning horizon (beyond the operating horizon). Second, we propose that transmission providers provide a process flow diagram that illustrates the various steps through which the ATC/AFC is calculated.

173. In addition, we propose to require transmission providers to include in Attachment  detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons. Thus, for TTC, a transmission provider should: (1) explain its definition of TTC; (2) explain its TTC calculation methodology (e.g., load flow, short circuit, stability, transfer studies); (3) list the databases used in its TTC assessments; and (4) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

174. For ETC, we propose to require a transmission provider to explain: (1) its  definition of ETC; (2) the calculation methodology used to determine the transmission capacity to be set aside for native load and non-OATT customers; (3) how point-to-point service requests are incorporated; (4) how rollover rights are accounted for; and (5) its processes for ensuring that non-firm capacity is released properly (e.g., when real time schedules replace the associated transmission service requests in its real-time calculations). With regard to (5), we seek comment on whether transmission providers

currently are keeping track of when firm service reservations are not scheduled and should be released as non-firm.

175. If a transmission provider uses an AFC methodology to calculate ATC, we propose to require it to explain: (1) its definition of AFC; (2) its AFC calculation methodology (e.g., load flow, short circuit, stability, transfer studies); (3) its process for converting AFC into ATC; (4) what databases are used in its AFC assessments; (5) the assumptions used in its AFC assessments; and (6) the reliability criteria used for contingency outages simulation.

176. For TRM, we propose to require a transmission provider to explain: (1) its definition of TRM; (2) its TRM calculation methodology (e.g., its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (3) the databases used in its TRM assessments; (4) the conditions under which the transmission provider uses TRM; and (5) the process used to prevent double-counting of contingency outages used in its TTC and TRM calculations. We propose to require transmission providers that do not reserve TRM to reflect that in Attachment C. We seek comment on the above proposal, specifically on what type of showing a transmission provider could make with regard to the process used to prevent double-counting.

177. Furthermore, in the CBM Order, the Commission required transmission providers to post a specific and self-contained narrative explanation of their CBM practices, including who performs the assessment (transmission or merchant staff), the methodology used to perform generation reliability assessments (e.g., probabilistic or

deterministic), whether the assessment method reflects a specific regional practice, the assumptions used in those assessments and the basis for the selection of paths on which CBM is set aside. In addition, the Commission directed transmission providers to post their procedures for allowing CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). The Commission further stated that if a utility's practice was not to reserve CBM, it should reflect that in Attachment C. We propose to require transmission providers to include this narrative in Attachment C of their OATTs.

178. In addition, for CBM, we propose to require a transmission provider to:

(1) explain its definition of CBM; (2) list the databases used in its CBM calculations; and (3) prove that there is no double-counting of contingency outages when performing CBM calculations.

179. Though we are proposing to require transmission providers to provide greater clarity in the description of their ATC calculations, it is our expectation that the reforms we propose for greater consistency of ATC methods will minimize the burden on transmission providers and customers of assessing various ATC calculation methodologies. Ultimately, when the ATC standards development process we propose is completed, we expect that Attachment C will refer to the NERC standards and will differ

by transmission provider only with respect to the limited elements of the ATC calculation that may not have been made consistent.

OASIS

180. The Commission’s existing regulations require certain ATC-related information to be posted on each transmission provider’s OASIS, while other information is required to be provided on request. To ensure that relevant information is available on a timely basis to all market participants, we propose to amend our regulations to allow potential customers greater access to information that will enable them to obtain service on a non-discriminatory basis from any transmission provider.¹⁷³ We believe that our proposed reforms will not only enhance the amount and accuracy of information available to customers, but will also increase the ability of the Commission and others to detect any potentially unduly discriminatory behavior in a transmission provider’s calculation and allocation of ATC.

181. Our regulations state that a transmission provider’s¹⁷⁴ ATC and TTC calculations shall be performed according to consistently applied methodologies referenced in the transmission provider’s OATT and shall be based on current industry practices, standards

¹⁷³ See 18 CFR 37.2 (2005).

¹⁷⁴ We note that various provisions of the OASIS regulations use the term “Responsible Party,” which means the transmission provider or an agent to whom the transmission provider has delegated the responsibility of meeting any of the requirements of the regulations. For simplicity, however, we will use the term “transmission provider” here.

and criteria.¹⁷⁵ We propose to revise this provision to include compliance with the reliability standards developed by the ERO – *i.e.*, ATC and TTC calculations shall be performed according to consistently applied methodologies referenced in the transmission provider’s OATT and shall be based on the ERO reliability standards as well as current industry practices, standards and criteria.

182. The regulations further state that, on request, a transmission provider must provide all data used to calculate ATC and TTC for any constrained paths.¹⁷⁶ Transmission providers also are required to make any system planning studies or specific network impact studies performed for customers to determine network impacts publicly available on request and to post a list of such studies on the OASIS.¹⁷⁷ The Commission proposes to maintain these requirements.

183. The Commission’s OASIS regulations require transmission providers to calculate and post ATC and TTC for each posted path.¹⁷⁸ The regulations define two classes of posted paths based on usage: “constrained” and “unconstrained.” A constrained posted path is any posted path for which ATC has been less than or equal to 25 percent of TTC at any time during the preceding 168 hours or is calculated to be less than, or equal to,

¹⁷⁵ See 18 CFR 37.6(b)(2)(i) (2005).

¹⁷⁶ See 18 CFR 37.6(b)(2)(ii) (2005).

¹⁷⁷ See 18 CFR 37.6(b)(2)(iii) (2005).

¹⁷⁸ See 18 CFR 37.6 (2005).

25 percent of TTC for any period during the current hour or the next 7 days. An unconstrained posted path is any posted path that is not a constrained posted path.¹⁷⁹ The Commission proposes to amend the regulations relating to the data posted for constrained posted paths, but largely to retain the existing posting requirements for unconstrained posted paths, as set forth below.

184. First, in the CBM Order, the Commission required transmission providers, with respect to each path for which the utility already posts ATC, to post (and update) the CBM figure for that path. The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS. The Commission proposes to incorporate these CBM posting requirements into its regulations.

185. With respect to paths for which the utility already posts ATC, TTC, and CBM, we further propose to require each transmission provider to also post (and update) the TRM value for that path.

186. Our existing regulations require ATC and TTC on constrained paths to be updated when: (1) transactions are reserved, (2) service ends, or (3) whenever the TTC estimate for the path changes by more than 10 percent. We do not believe that this regulation has

¹⁷⁹ See 18 CFR 37.6(b)(1)(iii)(2005). Our regulations require transmission providers to post ATC and TTC for specific time horizons for constrained posted paths and unconstrained posted paths. The Commission proposes to maintain the existing time horizons. See 18 CFR 37.6(b)(3)(i)-(ii) (2005).

resulted in sufficient information to determine why ATC values changed. To provide a transmission customer with useful information to assist with its evaluation of monthly and yearly firm transmission service options, we propose to supplement the existing regulations by requiring the transmission provider to post a brief, but specific, narrative explanation of the reason for the posted change in the monthly and yearly ATC values on a constrained path. This narrative would describe, for example: (1) scheduling of planned outages and occurrence of forced transmission outages; (2) de-ratings of transmission facilities; (3) scheduling of planned generation outages and occurrence of forced generation outages; (4) changes in load forecast, (5) changes in new facilities in-service dates, or other events or assumption changes that cause the ATC value to change.

We seek comment on whether the posting of this new information would provide adequate transparency to the customer on a frequent enough basis without imposing an undue burden on the transmission provider. We seek comment on whether a similar narrative also should be required when ATC remains unchanged at a value of zero for some specified period of time.

187. We propose to maintain the requirement in 18 CFR § 37.6(e)(2)(i) that a transmission provider must post the reason for a denial of a request for service. We propose, however, to amend this provision to require a transmission provider to maintain and make available information supporting the reason for the denial for five years. In addition, we propose to extend the time period for which transmission providers must maintain transmission service information for audit. Our regulations currently require

audit data to be retained and made available upon request for download for three years from the date when they are first posted.¹⁸⁰ We propose to change the period from three to five years.

188. In the CBM Order, the Commission stated that the level of ATC set aside for CBM can and should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized). Thus, the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the availability of CBM and to post on OASIS their practices in this regard. We propose to incorporate these requirements in the Commission's regulations and to require transmission providers to reevaluate the CBM set aside at least quarterly.

189. We also propose to require the transmission provider and network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of a network resource. As with other transmission request information posted on OASIS, the transmission provider should keep designation and termination information posted on OASIS for 90 days and should make designation and termination information available upon request for five years, consistent with 18 CFR 37.7(b) (2005). Transmission customers will be able to query requests to designate and terminate a network resource under 18 CFR 37.6(a)(6)(2005). We propose to require

¹⁸⁰ See 18 CFR 37.7(b) (2005).

the transmission provider to post on its OASIS a list of its current designated network resources and all network customers' current designated network resources. The list of network resources should include the name of the resource, its geographic and electrical location, and the amount of capacity from the unit to be designated as a network resource.

190. Finally, we remind transmission providers that transfer capability associated with transmission observations that are not scheduled in real time must be included in non-firm ATC and posted on OASIS.¹⁸¹

CEII

191. Shortly after the attacks on September 11, 2001, the Commission removed from public viewing certain documents that were likely to contain detailed specifications of critical infrastructure facilities. CEII is information concerning proposed or existing critical infrastructure (physical or virtual) that: (1) relates to the production, generation, transportation, transmission, or distribution of energy; (2) could be useful to a person in planning an attack on critical infrastructure; (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. § 552 (2000); and (4) does not simply give the location of the critical infrastructure. Accordingly, access to transmission-related information collected by the Commission has been restricted by the Commission's CEII regulations. Thus, for example, information filed in FERC Form

¹⁸¹ Our regulations require non-firm ATC and TTC for constrained posted paths to be posted in the same manner as firm ATC and TTC, except that monthly and seasonal capacity need only be posted if requested. See 18 CFR 37.6(b)(3)(i)(B)(2005).

No. 715 (including base case power flow data and transmission system maps) as well as system planning and network impact studies and models are no longer publicly available. However, requesters with a particular need (such as transmission customers and consultants with legitimate needs) have the opportunity to access information designated as CEII from the Commission by submitting a request to the Commission under the procedures set forth in our regulations. In Order No. 643,¹⁸² the Commission addressed situations in which its regulations require public utilities to disclose information directly to the public. The Commission ruled that potential CEII disclosed directly from the public utility to the public should be evaluated under the same rules addressing the disclosure of CEII from the Commission to the public, *i.e.*, if an entity concludes that certain of its information is CEII, it must designate it as such and provide other specified information about obtaining access to the CEII through the Commission's process. The Commission also held that it did not intend to restrict an entity's ability to reach appropriate arrangements for sharing CEII, and that all persons with a legitimate need for CEII should be able to gain access to it with a minimum of difficulty.¹⁸³

192. We believe that much of the information we propose to require transmission providers to provide in this proposed rulemaking will not pose CEII concerns. If

¹⁸² Amendments to Conform Regulations with Order No. 630, Order No. 643, 68 FR 52089 (Sep. 2, 2003), FERC Stats. & Regs. ¶ 31,149 (2003).

¹⁸³ Id. at P 16.

commenters believe that any of the information is CEII, they should explain the basis for that view. We recognize that requiring interested persons to use the existing CEII process to access information we propose to require transmission providers to provide in this rulemaking could undermine our goal of providing increased transparency to information necessary to evaluate the use of the transmission system. As a result, we seek comment on procedures that could be adopted by transmission providers to streamline the resolution of CEII concerns and allow timely disclosure of information from the transmission providers to interested persons.

Additional Data Posting

193. Notwithstanding our proposed reforms requiring greater consistency of and increased transparency into ATC calculation methodologies, certain aspects of ATC calculation may remain committed to the discretion of the transmission provider. Thus, we believe that additional reporting requirements may be necessary to detect undue discrimination. Accordingly, we propose to add a requirement in our regulations for transmission providers to post on OASIS certain metrics related to the provision of transmission service under the pro forma OATT. Specifically, we propose to require transmission providers to post data each month concerning transmission service requests associated with particular paths or flowgates that would clearly identify the number of requests that have been accepted and the number of requests that have been denied during the prior month. The posted data would show: (1) the number of non-affiliate requests for transmission service that have been rejected and (2) the total number of non-affiliate

requests for transmission service that have been made. This posting would distinguish between the length of the service request (e.g., short-term or long-term requests) and between the type of service requested (e.g., firm point-to-point, non-firm point-to-point or network service). We also propose that the transmission provider post similar information for affiliate transactions. In other words, the transmission provider would also post: (1) the number of affiliate requests for transmission service that have been rejected, and (2) the total number of affiliate requests for transmission service that have been made. Similarly, this posting would distinguish between the length of the service request (e.g., short-term or long-term requests) and between the type of service requested (e.g., firm point-to-point, non-firm point-to-point or network service).

194. Another area of discretion is the load forecasts used by the transmission provider when computing ATC. The Commission recognizes that the lack of transparency regarding transmission providers' forecasted and actual use of the transmission system makes it difficult to determine whether an appropriate amount of capacity is being set aside for service to native load. To address this concern, we are considering additional posting requirements. For example, should transmission providers make available their underlying load forecast assumptions for all ATC calculations? In addition, should transmission providers post, on a daily basis, their actual daily peak load for the prior day? We believe that this posting of forecasted and actual loads would allow the Commission and others to make a meaningful comparison of these elements. We invite comment on whether this information would be helpful for such a comparison. We also

seek comment on the overall benefits of posting metrics and on potential alternative metrics.

195. For all of our proposed OASIS reforms, we propose to require public utilities, working through NAESB, to develop standards for consistent methods of posting the new requirements on OASIS so that a common format is used.

B. Transmission Planning – Coordinated, Open and Transparent Planning

196. Order No. 888 set forth certain minimum requirements for transmission system planning. For example, the pro forma OATT requires transmission providers to plan for the transmission needs of their network customers on a comparable basis (section 28.2), and it requires them to expand their systems to accommodate firm point-to-point customer requests (sections 13.5 and 15.4) that cannot be satisfied due to transmission constraints or satisfied more economically via redispatch. In addition, in Order No. 888-A, the Commission encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. The Commission also encouraged regional planning so that the needs of all participants are represented in the planning process.¹⁸⁴ However, the Commission did not require joint planning between transmission providers and their

¹⁸⁴ See Order No. 888-A at 30,311.

customers or between transmission providers in a given region,¹⁸⁵ nor did it impose any specific requirements regarding the manner in which transmission providers should coordinate their transmission system planning with their pro forma OATT customers. The only section of the pro forma OATT that directly speaks to joint planning is section 30.9, which provides that for facilities constructed by a network customer, the network customer must receive credit where such facilities are jointly planned and installed in coordination with the transmission provider.¹⁸⁶

197. In the NOI, the Commission asked several questions about joint planning between transmission providers and their customers. For example, we asked whether joint planning should be made mandatory, particularly when transmission requests affect adjacent transmission systems. We also inquired whether joint planning should be subject to an annual reporting requirement or audits. Additionally, we asked for comment on a number of issues designed to determine whether any pro forma OATT reforms are necessary to ensure that the transmission system is expanded so that customers have adequate transmission service. As the comments below indicate, commenters generally all believe that joint and regional planning are necessary and

¹⁸⁵ See id.

¹⁸⁶ Pro forma OATT section 21.2, “Coordination of Third-Party System Additions,” provides for certain rights for transmission providers to coordinate construction of facilities on their systems associated with point-to-point customer requests and related construction on a third-party transmission system, but imposes no obligation on transmission providers.

desirable, but there is a split over whether it should continue to be voluntary or should be made a requirement.

Comments Supportive of Mandatory Joint and Regional Planning

198. A number of commenters contend that joint planning between transmission providers and their customers should be required by the pro forma OATT. Most of these commenters also advocate joint planning among transmission providers in a given region. In perhaps the strongest comments on the topic, TDU Systems and TAPS request that the Commission mandate an open, regional transmission expansion planning process that provides opportunities for transmission customers to join and participate in the planning process. Many other commenters also support joint and regional planning in some form or another, with some focusing particularly on requiring such planning when adjacent transmission systems are affected.¹⁸⁷ Bonneville and Williams also assert that there is already Commission precedent for joint planning in our procedures on large generator interconnections, which require the coordination of studies when interconnection requests affect other systems. EPSA states that the Commission should require that neighboring systems formalize the process under which broad regional models are developed and used to study requests on any system within a broadly defined region. Powerex points out that

¹⁸⁷ E.g., AEP, Alcoa, APPA, Bonneville, Calpine, EPSA, Lafayette, National Grid, NCPA, NRECA, Old Dominion, Trans-Elect, Williams, and Xcel. Though it does not generally support mandatory joint and regional planning, EEI recommends that the Commission modify the pro forma OATT to address planning when transmission requests require upgrades on or otherwise adversely affect adjacent transmission systems.

the lack of regional transmission planning is one of the most difficult issues faced in the Pacific Northwest, and PPL asserts that transmission planning and expansion in the Western Interconnection does not support a competitive market.

199. In addition, many commenters contend that transmission providers should be required to report on an annual basis the joint and regional planning that has occurred or been requested.¹⁸⁸ TAPS states that an annual filing noticed by the Commission that gives the public an opportunity to comment should be buttressed with audits, in order to ensure that transmission providers are taking joint planning with their network customers (and neighboring systems) seriously. EPSA likewise contends that transmission providers should be required to report to the Commission on an annual basis the joint planning that has occurred or been requested on their systems, and that the Commission should conduct audits to determine the level of compliance with any joint planning requirement or agreement.

200. The commenters that advocate mandatory joint and regional planning assert that it is needed because transmission providers unduly discriminate against their customers when planning their transmission systems. For example, a number of commenters assert that transmission providers meet their own needs for transmission planning and construction before (and often without) meeting those of their customers.¹⁸⁹ NRECA

¹⁸⁸ E.g., East Texas Cooperatives, EPSA, FMPPA, MidAmerican, and TAPS.

¹⁸⁹ E.g., FMPPA, Midwest Municipals, NCPA, and NRECA.

asserts that since the implementation of Order No. 888, a number of public utility transmission providers – despite clearly stated obligations in the pro forma OATT – have not planned for their load-serving transmission customers on a basis comparable to that of their own bundled retail native load. TDU Systems believe that joint and regional transmission planning is a critical component of ensuring comparability between a transmission provider's use of the transmission system and a network customer's use of the transmission system, largely because transmission providers have an incentive to thwart the expansion planning process. Both NRECA and TDU Systems argue that the planning processes in RTOs and ISOs also are insufficient because they often only allow customer input after transmission plans are developed by individual transmission providers.

201. TAPS asserts that the absence of joint planning has resulted in unduly discriminatory transmission service. For comparable service to be a reality, TAPS asserts that the transmission system must be planned and built for customer needs, just as it must be planned and built to meet the transmission providers' need to provide service to their native loads. Old Dominion contends that transmission providers often locate transmission in such a way that it favors their own generation. According to Lafayette, transmission providers have increased their generation dominance by inadequately planning for the needs of their transmission customers so that they are unable to turn to alternative suppliers. East Texas Cooperatives also argues that some transmission providers continue to plan their systems in isolation from the needs of other load-serving

entities. EPSA concludes that the transmission needs of non-transmission provider customers are simply not integrated effectively into the planning process. APPA notes that the original goal of the pro forma OATT -- an inclusive planning process that takes into account on a comparable basis the load growth and new generation resource needs of all loads served using the transmission provider's system -- has not been achieved. Many commenters assert that joint and regional transmission planning is necessary in order to ensure adequate infrastructure development.¹⁹⁰ Others focus on the need for joint and regional planning to address the fact that changes on one system often affect transmission service on adjacent systems.¹⁹¹ Lastly, APPA blames substantial and rising congestion costs on inadequate transmission planning, and EPSA contends that better transmission planning is needed to support a competitive electricity market.

Comments Supportive of Voluntary Joint and Regional Planning

202. Another large group of commenters, including many investor-owned utilities, stress that joint and regional planning, while laudable, should not be mandatory and that it should continue to be voluntary or that processes are already in place to encourage

¹⁹⁰ E.g., AEP, Calpine, Constellation, East Texas Cooperatives, ELCON, NRECA, and TransAlta.

¹⁹¹ E.g., Alcoa and EPSA. EEI acknowledges the planning difficulties that arise when a transmission request on one system causes the need for upgrades to another system.

regional planning.¹⁹² Progress Energy, for example, contends that there are several formalized processes in place today that foster joint and regional planning, such as the process in North Carolina. Southern points out that in addition to participating in Southeastern Electric Reliability Council (SERC) planning activities, it is engaged in other types of joint regional planning (e.g., through the Georgia Integrated Transmission System (Georgia ITS)).¹⁹³ Nevada Companies supports the approach already used in the WECC, which employs interconnection-wide models for planning. Nevada Companies explains that these studies are then made available to all other WECC transmission providers. In addition, APS, Tacoma, and WAPA point to numerous forums (e.g., the Southwest Area Transmission planning group and the Southwest Transmission Expansion Plan process) where transmission providers and other industry stakeholders coordinate their transmission plans. LPPC also states that the Georgia ITS has provided benefits to participants and the region – in the form of improved investment in infrastructure and through the introduction of new sources of capital. Lastly, some

¹⁹² E.g., Cinergy, Entergy, KCP&L, LPPC, MidAmerican, Nevada Companies, North Carolina Commission, Northwestern, PNM-TNMP, Progress Energy, Salt River, Snohomish, South Carolina Regulatory Staff, Southern, Tacoma, and WAPA. Nevertheless, KCP&L, Nevada Companies, and Progress Energy join with EPSA in calling for a more formalized process for addressing base case and expansion plans.

¹⁹³ Georgia ITS consists of jointly-owned transmission facilities, which are owned by the Southern subsidiary Georgia Power, the Municipal Electric Authority of Georgia, the Georgia Transmission Corporation – a cooperative utility – and Dalton Utilities – a municipal system.

commenters point out that collaborative regional planning already occurs in RTO and ISO regions.¹⁹⁴ With regard to PJM, however, TDU Systems argues that better transmission planning is required due to PJM’s “rubber-stamping” of transmission provider identified transmission upgrades. Exelon states that the Northeastern ISO/RTO Planning Coordination Protocol is a formal agreement, executed in 2004, among the PJM Interconnection, the New York Independent System Operator, and ISO New England, pursuant to which the three organizations conduct a comprehensive process of coordinating system planning activities.

203. With regard to the imposition of reporting requirements, many commenters argue that transmission providers already are required to report joint planning activities.¹⁹⁵ EEI, for example, contends that joint planning activities under section 30.9 of the pro forma OATT currently are required to be reported on each transmission provider’s OASIS. EEI argues that audits should not be required. Bonneville contends that, at least in the Pacific Northwest, annual reporting and audits are not needed. Bonneville states that transmission planning staffs already bear a heavy workload; for example, Bonneville’s planning staff must address many requests for transmission and interconnection service, as well as conduct regional planning efforts and comply with regional and national reliability initiatives. Northwestern states that reporting

¹⁹⁴ E.g., Ameren, CAISO, Exelon, ISO New England, and MidAmerican.

¹⁹⁵ E.g., Bonneville, EEI, KCP&L, PNM-TNMP, Salt River, Tacoma, and WAPA.

requirements or audits are not needed and would be burdensome to the transmission provider, distracting it from performing its joint planning responsibilities.

Current pro forma OATT Planning Responsibilities

204. Order No. 888 and the pro forma OATT require that transmission providers plan and upgrade their transmission systems to provide comparable open access transmission service for their transmission customers. For example, with regard to network service, section 28.2 of the pro forma OATT provides that the transmission provider “will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider’s Transmission System.”

Section 28.2 also provides that the Transmission Provider shall, consistent with Good Utility Practice, “endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer’s Network Resources to serve its Network Load on a basis comparable to the Transmission Provider’s delivery of its own generating and purchased resources to its Native Load Customers.”

205. The pro forma OATT also requires that new facilities be constructed to meet the service requests of long-term firm point-to-point customers. Section 13.5 of the pro forma OATT requires the transmission provider to consider redispatch of the system to relieve any constraints that are inhibiting a transmission customer’s point-to-point service if it is economical to do so; but if redispatch is not economical, the transmission provider is obligated to expand or upgrade its system. This expansion obligation on the part of the

transmission provider for point-to-point service is found in section 15.4 of the pro forma OATT, which provides that when a transmission provider cannot accommodate a point-to-point transaction because of insufficient capability on its system, it will “use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service.” Section 15.4 goes on to provide that “the Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities.” **Importantly, however, the transmission provider’s obligation to upgrade or expand its system to provide point-to-point service as detailed in section 15.4 is contingent on the transmission customer agreeing to compensate the transmission provider for such costs pursuant to the terms of section 27 (providing for cost responsibility for upgrades and/or redispatch “to the extent consistent with Commission policy”).** Order No. 888 does not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans.¹⁹⁶

¹⁹⁶ Certain transmission data is required to be provided annually in the FERC Form 715 (e.g., Part 2 – Power Flow Base Cases, Part 3 – Transmitting Utility Maps and Diagrams, Part 4 – Transmission Planning Reliability Criteria, Part 5 – Transmission Planning Assessment Practices, and Part 6 – Evaluation of Transmission System Performance). As discussed below, we do not believe that the FERC Form 715 reporting requirements have satisfied the need for transparency with regard to transmission planning.

The Need for Reform

206. As discussed more fully in Part III.C above, in the ten years since Order No. 888 was issued, the Nation has witnessed a decline in transmission investment relative to load growth. As a result, transmission capacity per MW of peak demand has declined in every NERC region, and it has been estimated that capital spending must increase significantly to ensure system reliability and to accommodate wholesale electric markets. Many have argued that inadequate expansion of the transmission grid has contributed to the widespread transmission constraints that plague most regions of the country, as reflected in the limited amounts of ATC posted in many regions, increased frequency of denied transmission services requests, and increasingly common transmission service interruptions or curtailments, all of which make it more difficult for transmission customers to transfer power. In short, it has become clear that since Order No. 888 was issued, the Nation's transmission grid has not been planned and developed adequately and projections suggest that without reform this trend will continue.

207. The need for transmission planning reform also has been recognized by the Consumer Energy Council of America (CECA), a public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues. CECA launched its Transmission Infrastructure Forum

in early 2004,¹⁹⁷ which published its conclusions in January 2005 in a final report titled “Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability” (CECA Report).¹⁹⁸

Among other things, the CECA Report concludes that regional transmission planning with consumer input early in the process is needed to ensure the development of a robust transmission system capable of meeting consumer needs reliably and at reasonable cost over time. The CECA Report stresses that regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, as well as critical infrastructure to support national security and environmental concerns.¹⁹⁹

208. Transmission providers have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. As the Commission noted in Order No. 888, “[i]t is in the economic self-interest of transmission monopolists, particularly those with high-cost

¹⁹⁷ The CECA Transmission Infrastructure Forum included representatives from such diverse constituencies as investor-owned utilities, rural electric cooperatives, municipal power systems, federal power systems, independent power producers, equipment manufacturers, the U.S. Congress, the Commission, the U.S. Department of Energy, state legislatures, state public utility commissions, state energy offices and consumer advocates, consumer and environmental organizations, independent consultants, and academic institutions.

¹⁹⁸ Available at <http://www.cecacf.org/Publications/PublicationsAllDate.html>.

¹⁹⁹ See, e.g., CECA Report at 10-11.

generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves.”²⁰⁰ This statement continues to be true today. In upholding the Commission’s authority to require open access in Order No. 888, the court in TAPS v. FERC noted that “[u]tilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers.”²⁰¹ Thus, even when transmission providers do address congestion, they have an incentive to do so in a manner that benefits their own generation or loads rather than the generation or loads of their competitors. These disincentives frustrate new investment that could remedy both “local” congestion (i.e., within the transmission provider’s control area) and congestion between control areas, as well as remedy undue discrimination and increase bulk power trade. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will

²⁰⁰ Order No. 888 at 31,682.

²⁰¹ 225 F.3d at 684; see also New York v. FERC, 535 U.S. at 8-9 (addressing Order No. 888’s open access requirements, the Court noted that “public utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities’ control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors’ power on terms and conditions less favorable than those they apply to their own transmissions.”) (citation and footnote omitted).

make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.

209. The existing pro forma OATT does not adequately address the above-referenced problems. As noted, there is no general requirement that a transmission provider coordinate its transmission planning with customers, market participants, or its interconnected neighbors.²⁰² Additionally, though the pro forma OATT does require transmission providers to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. Rather, the transmission provider currently is allowed to create its own transmission plan with limited or no input from affected market participants or other affected entities, such as state commissions. There is also no requirement that the planning process be transparent. While we recognize that certain planning information is required to be filed annually in FERC Form No. 714 – Annual Electric Control and Planning Area Report and FERC Form 715 – Annual Transmission Planning and

²⁰² As discussed more fully in Part V.C.2, section 30.9 of the current pro forma OATT may inhibit coordinated planning by making transmission providers reluctant to engage in coordinated planning, because of the requirement to give customers credits for jointly planned facilities. We are proposing to sever the link between credits and planning, and treat the two issues separately within the pro forma OATT.

Evaluation Report, this does not appear to provide sufficient transparency to remedy the remaining concerns expressed in this proceeding about the potential for undue discrimination in planning.

210. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no input into whether a particular plan treats all loads and generators comparably. Without sufficient transparency, market participants have no means to determine whether the plan developed by the transmission provider in isolation is discriminatory. Moreover, the process is inefficient. Disputes over discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning. The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service, and therefore, an obligation to remedy these transmission planning deficiencies. The Commission's authority to remedy undue discrimination is broad.²⁰³ In addition, new section 217 of the FPA requires the Commission to use its FPA authorities in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. Finally, we note that a more transparent and

²⁰³ See Order No. 888 at 31,669 (noting that the FPA “fairly bristles” with concern for undue discrimination (citing Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987))).

coordinated regional planning process can support the DOE's responsibilities under EPCRA 2005 section 1221 to study transmission congestion and issue reports designating National Interest Transmission Corridors.

211. We are encouraged that since the adoption of open access in Order No. 888, a number of voluntary coordinated and regional planning efforts have been developed throughout the country, including those administered by RTOs and ISOs. For example, each of the Commission-approved RTOs in the Northeast, Midwest and Southwest, as well as CAISO, provide for a coordinated and regional planning process with stakeholder input from each industry segment. The Commission also notes that there are several other promising efforts to establish voluntary coordinated and regional planning efforts around the country. For example, WECC is in the process of expanding its reliability responsibilities to include comprehensive transmission planning to address the regional economic transmission needs of its members and other stakeholders in its regional footprint. In addition, each of the subregions in WECC has a coordinated transmission planning process that, in varying degrees, is open to market participants and, in some instances, has resulted in significant new transmission being built on a joint ownership basis. In North Carolina, Duke, Progress Energy, and two other organizations – North Carolina Electric Membership Corporation and ElectricCities of North Carolina, Inc. – have endeavored to create and implement a collaborative electric transmission planning process in that state. This process provides for broad stakeholder input as well an

independent facilitator. Other models for coordinated planning include the Georgia ITS and joint ownership arrangements like it around the country.

212. We fully support these voluntary efforts and believe they are consistent in significant respects with the nature of the reforms we are proposing for transmission planning under the pro forma OATT. In those regions and subregions that already have adopted significant reforms, our proposal may require only modest changes, while other regions and subregions may need to undertake more significant changes to the way in which the transmission system is planned today.

213. Today, numerous competing interests have a need to utilize the transmission grid, and yet in many areas of the country that grid is planned much the same way as it was before the electric industry matured into a regional business and Order No. 888 was implemented. That is, the same public utilities that own and control the grid also control the planning process that governs when and how the grid is expanded and upgraded. In short, the transmission grid is being utilized in a fundamentally different way, consistent with the intent of open access, and a decade of experience has shown us that in order to remedy undue discrimination, the existing provisions of the pro forma OATT respecting transmission system planning must be reformed. Accordingly, in order to provide for more comparable open access transmission service, eliminate the potential for undue discrimination and anticompetitive conduct, and satisfy our statutory responsibilities under section 217 of the FPA, we propose that each public utility transmission provider participate in an open and transparent local and regional planning process that addresses

certain fundamental principles of transmission planning. As we indicated above, existing regional planning processes will be expected to meet or exceed the transmission planning principles we outline in this proposed rule.

Coordinated, Open, and Transparent Transmission Planning

214. In order to eliminate the potential for undue discrimination as described above, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we propose to amend the pro forma OATT to **require coordinated, open, and transparent transmission planning on both a local and regional level.** We propose to require each public utility transmission provider to submit, as part of its compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the following coordinated and regional planning principles.²⁰⁴ In the alternative, transmission providers may make a compliance filing in this proceeding describing their existing coordinated and regional planning process and showing that it is consistent with or superior to the requirements set forth below. Moreover, we expect municipal, cooperative, and other public power entities to participate in these processes as well, consistent with their obligation to provide reciprocal transmission service as detailed in Order No. 888. An open and transparent regional planning process cannot succeed unless all transmission owners participate.

²⁰⁴ The revised pro forma OATT reflects the proposed planning requirement in sections 15.4, 16.1, 17.2(x), 28.2, 29.2, 31.6, and Attachment K.

Under our proposal in this NOPR, a coordinated, open and transparent process must satisfy the following eight principles:

1. Coordination – The transmission provider must meet with all its transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis. The Commission seeks comment on specific requirements for this coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features deemed important by commenters.
2. Openness – Transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers, and state commissions). The Commission seeks comment on whether there are any circumstances under which participation should be limited, e.g., to address confidentiality concerns.
3. Transparency – The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its transmission system plans. The Commission seeks comment on whether the information provided in FERC Form 715 is adequate and, if not, what additional detail should be provided. The Commission also seeks comment on the format for disclosure, including protections to address confidentiality concerns.

4. Information Exchange – Network transmission customers are required to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load; and point-to-point customers are required to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. The Commission seeks comment on whether specific requirements should be adopted for this information exchange.²⁰⁵ The transmission provider must allow market participants the opportunity to review and comment on draft transmission plans.
5. Comparability – After considering the data and comments supplied by market participants, the transmission provider is to develop a transmission system plan that: (1) meets the specific service requests of its transmission customers; and (2) otherwise treats similarly situated customers (e.g., network and retail native load) comparably in transmission system planning.

²⁰⁵ For network service, some of this information already is required by sections 29, 30 and 31 of the pro forma OATT, but to the extent it is not, we propose to require customers to provide additional information as necessary for the transmission provider to develop a system plan.

6. Dispute Resolution – The transmission provider must propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third-party neutral. The Commission’s Dispute Resolution Service is available to assist transmission providers in developing a dispute resolution process. In addition to informal dispute resolution, affected parties would have the right to file complaints with the Commission under FPA section 206. The Commission seeks comment on whether any specific dispute resolution processes should be required.
7. Regional Participation – In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, the transmission provider is required to coordinate with interconnected systems to: (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and (2) identify system enhancements that could relieve “significant and recurring” transmission congestion (defined below). The Commission strongly encourages that such coordination encompass as broad a region as possible, given the interconnected nature of the transmission grid and the efficiency of addressing these issues in a single forum. The Commission also recognizes that, as in the West, it may be appropriate to organize regional planning efforts on both a subregional and regional level. The Commission seeks comment on whether there are existing institutions (such as the NERC

regional councils or subregional planning groups) that are well situated to perform or coordinate this function.

8. Congestion Studies – The transmission provider is required annually to prepare studies identifying “significant and recurring” congestion and post such studies on its OASIS. The studies should analyze and report on the location and magnitude of the congestion; possible remedies for the elimination of the congestion, in whole or in part; the associated costs of congestion; and the cost associated with relieving congestion through system enhancements (or other means). The Commission seeks comment on how to define “significant and recurring” congestion, such as by reference to generation redispatch, repeated denials of service requests, zero ATC, frequent curtailments or a combination of these factors. The required congestion studies would address both “local” congestion (*i.e.*, within the transmission provider’s system) and congestion between control areas and subregions. The purpose of this requirement is to ensure that affected market participants, state commissions, and this Commission understand both the costs of recurring transmission congestion and the remedies. The Commission seeks comment on how this information should be used by the transmission provider and market participants to address significant and recurring congestion.

215. The Commission encourages the use of an independent third party to oversee or coordinate the planning process. The Commission is not proposing to require an independent third party to control the process, but does believe that independence can provide greater confidence in the planning process and resulting studies. Independence can take many forms, from having an independent entity resolve disputes over planning assumptions and decisions (as in an RTO) to having an independent consultant coordinate and otherwise perform the annual congestion studies referred to above. The Commission seeks comment on the levels of independence that can provide benefits and the institutions that could offer such independence, such as whether Regional Entities under the ERO could provide such independence.

216. Additionally, the Commission strongly encourages the participation of state commissions and other state agencies, particularly with regard to regional planning, in the coordinated transmission planning processes being proposed in this NOPR. The participation and support of state commissions and other state agencies is important because state commissions regulate the cost of transmission that is included in bundled retail rates and states also perform transmission siting. Many states also have traditionally been involved in utility planning in some way for their state or region. The Commission seeks comment on how best to accommodate effective state participation.

217. The Commission seeks comment on several aspects of this proposal. First, the Commission seeks comment on how much flexibility each transmission provider in a region should be given in implementing any principles adopted. Second, the Commission

seeks comment, by way of examples, on transmission planning processes that comply with the proposed transmission planning reforms in principle.

218. Third, we seek comment on whether there are other principles or requirements that should be adopted to support the construction of needed new infrastructure and otherwise ensure that all market participants are treated on a comparable basis. For example:

- a. We seek comment on whether there should be a principle or guideline to govern the recovery and allocation of costs associated with funding the regional planning requirement. To devote the resources necessary to support an open and transparent regional planning process, we recognize that the participating entities must be assured of recovery of their costs, as well as assured that the costs will be borne equitably by all parties benefiting from the process.
- b. We seek comment on whether there should be a requirement that, at least for large new transmission projects (such as new regional backbone facilities), there be an open season to allow market participants to participate in joint ownership of these projects. We believe that such a requirement could stimulate more investment in the grid and ensure that all customers have the ability to participate in new projects on a nondiscriminatory basis, including smaller market participants that cannot

support the construction of large new facilities on their own.²⁰⁶ We seek comment on whether to include such a requirement and, if so, what conditions or limitations should be associated with it.

- c. We further seek comment on whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion. Such a process would allow interested entities, including state resource agencies, siting bodies and commissions, load-serving entities, or other market participants to request that the transmission provider model grid upgrades needed to accommodate the construction of new resources, e.g., remote coal, nuclear or wind on a local and regional basis and prior to the existence of an actual proposal for such resources. Such a process could provide the information necessary to allow interested entities to proactively evaluate, on a nondiscriminatory basis, different resource options in light of the differing

²⁰⁶ We note that transmission providers in the Western Interconnection already participate in regional and sub-regional transmission planning processes that include the opportunity for joint financing and ownership of transmission facilities. Such facilities are typically owned by the participants as “tenants in common” with each participant owning a pro rata share of the land and common facilities and sharing the costs and expenses in proportion to their ownership percentage in each project. Additionally, all owners participate in the oversight and administration of jointly-owned projects through representation on various administration committees. Among other benefits, this has allowed all participating utilities, large and small, to take advantage of the economies of scale associated with larger transmission projects.

transmission infrastructure needs associated with them. We recognize that resource planning is traditionally performed at the state level and do not believe that any such study process would conflict with these state prerogatives. To the contrary, we believe such a study process could provide states better information to evaluate all relevant resource options in exercising their resource adequacy authority.

- d. We also seek comment on whether we should require public utilities to develop cost allocation principles to address the sharing of the costs of new transmission projects. Would the development of specific cost allocation principles provide greater certainty and hence support the construction of new infrastructure? Or is cost allocation better handled on a case-by-case basis? We also seek comment on how, as part of any cost allocation process, to address the fact that upgrades that may not be needed for reliability in the near term (e.g., 3-5 years) may be necessary to support reliability in the longer term (e.g., 10-15 years). Furthermore, because transmission upgrades, particularly multi-state regional backbone facilities, often can require 10 to 15 years to construct, we seek comment on whether the planning process proposed here should be required to look out at least as far as the longest time it would take to build such an upgrade in the region in question.

219. Finally, the Commission seeks comment on the level of detail to be required in transmission providers' OATTs.

C. Transmission Pricing

220. Order No. 888 and the pro forma OATT included primarily non-rate terms and conditions of open access non-discriminatory transmission service. The Commission required transmission providers to propose corresponding rates in a subsequent filing under FPA section 205. Similarly, here we do not propose to undertake a comprehensive overhaul of our transmission pricing policies. We do, however, propose a number of reforms to several discrete provisions in the pro forma OATT, as further described below. We also provide a clarification of our policy for pricing of system expansions.

1. Imbalances

Energy Imbalances

221. In Order No. 888, the Commission concluded that six ancillary services must be included in an OATT.²⁰⁷ One of those ancillary services is energy imbalance service under Schedule 4 of the pro forma OATT.²⁰⁸ Energy imbalance service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its

²⁰⁷ Order No. 888 at 31,703.

²⁰⁸ Id.

Comment Form for First Posting revisions to MOD-001-1 Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies

Please use this form to submit comments on the first draft of the ATC/TTC Methodology Documentation Standard. Comments must be submitted by **June 28, 2006**. You must submit the completed form by emailing it to sarcomm@nerc.com with the words "ATC/TTC Methodology" in the subject line. If you have questions please contact Maureen Long at maureen.long@nerc.net or 813-468-5998.

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<input type="checkbox"/> NA – Not Applicable	<input type="checkbox"/>	9 — Federal, State, Provincial Regulatory or other Government Entities