Summary Consideration of Comments:

The Drafting Team has reviewed the comments and made some changes to the standard to address these comments.

1. As requested by BPA and others, the standard was modified to be clear that MOD-001 does not require conversion of AFC to ATC. While the OASIS Requirements require that ATC be posted, the Drafting Team could not find any reason that AFC must be converted to ATC for reliability. MOD-030 continues to provide the equation to convert AFC to ATC, that shall be used 'when' the conversion occurs, but the NERC standards do not define 'when' that conversion must occur. The standard now uses the phrase "ATC or AFC", where applicable. While the use of 'or' is not typically used in standards, since any Transmission Service Provider is only required to calculated either AFC or ATC, based on method that was selected, the use of 'or' is appropriate.
2. The title and purpose were modified to more clearly reflect the reliability aspects of 'why' ATC and AFC are calculated
3. All VRFs were set to "Lower" in response to industry comments. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
4. R2 has changed such that only 48 Hourly values are required instead of 168 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily values provide the necessary reliability information for time periods more than 48 hours in the future.
5. In R6 (and R7) we clarified that assumptions need to be 'no more limiting' rather than 'consistent'. In addition, the existing R6 was split to clarify which aspects the Transmission Operator and Transmission Service Provider are responsible for. Measures were expanded to be more clear.
6. A more graded approach was applied to the VSLs where appropriate
7. The Transmission Service Provider was given an 80-hour-per-year grace period in R8 for scheduled or unscheduled outages of any ATC calculation software that impact the hourly calculation.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/standards/newstandardsprocess.html.

Entity	Comment
Alabama Power Company	We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
American Electric Power	1. This standard places obligations on the registered "Transmission Operator" however, in many cases around the continent, there are 'registered' TOPs that do not calculate ATC both by tariff (ERCOT for example) or SPP where ATC is calculated, but not by the TOPs, but by the RTO. This standard must have an exemption for TOPs that do not calculate ATC. Delegation to the party that does calculate it is not an appropriate solution, because the TO does not have the responsibility to calculate, therefore it cannot delegate. Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. For similar reasons, the Drafting Team believes that the Transmission Operator does have an obligation to calculate TTC or TFC. The Transmission Operator has the ability to delegate these responsibilities to the Transmission Service Provider if desired. 2. As this standard is written, the Transmission Operat or has only 2 responsibilities -- R1 to pick a calculation method for the TSP to use to calculate ATC, and R6 where the TOP must calculate consistent with planning studies. If the TOP doesn't calculate ATC, why this obligation? Even so, how would 'compliance' be measured. Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. For similar reasons, the Drafting Team believes that the Transmission Operator does have an obligation to calculate TTC or TFC, which is incorporated in the individual methodology standards. We have modified the standard to make this more clear. The Transmission Operator has the ability to delegate these responsibilities to the Transmission Service Provider if desired. 3. All ATC calculation issues should be on the TSP, there should be no obligation on this subject placed on the TOP. Response: The Drafting Team has modified R6 and the associated measure and VSL to be clear that the responsibility of the Transmission Operator is to determine TTC or TFC, not to calculated ATC. 4. When this is accepted, MOD-013 is retired because those requirements are within this MOD-001 standard. TTC (FAC-012) is a reliability number and should not fall under ATC related standards. Response: These ATC standards are also reliability standards, therefore, the inclusion of the TTC requirements is appropriate within these standards.
AEP Marketing	1. This standard places obligations on the registered "Transmission Operator" however, in many cases around the continent, there are 'registered' TOPs that do not calculate ATC both by tariff (ERCOT for example) or SPP where ATC is calculated, but not by the TOPs, but by the RTO. This standard must have an exemption for TOPs that do not calculate ATC. Delegation to the party that does calculate it is not an appropriate solution, because the TO does not have the

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3. All ATC calculation issues should be on the TSP, there should be no obligation on this subject placed on the TOP.
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<tr><td colspan="2">Response: Please see in-line responses. Note that similar comments have been grouped and responded to once.</td></tr>
<tr><td>Associated Electric Cooperative, Inc.</td><td>The VSLs are very high for something that may be minor. If an entity is typically calculating AFC or ATC every hour, however due to some software or maintenance issue misses one on the hours why would the severity level be so high? I think it is inappropriate to have the VSL be high. It should be minor in this case.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has reviewed the quantity of ATCs that were required in R2 and has changed the requirement from 168 Hourly values to 48 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily values provide the necessary reliability information for time periods more than 48 hours in the future.
The VSLs have been modified to include a graduated approach.</td></tr>
<tr><td>Barry Green Consulting Inc.</td><td>Transparency: The former NERC standard for ATC required only that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose.
We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be</td></tr>
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The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to it. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID is reminiscent of the former ATC standard and cannot assure market participants of a sufficient degree of standardization.</td></tr>
<tr><td colspan="2">Response: The standard in R4 and R5 specifies the reliability entities to which the ATCID will be supplied, and NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation.</td></tr>
<tr><td>Bonneville Power Administration</td><td>The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1:
– Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL.
– Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6.
– Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".</td></tr>
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	– Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6. – Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".
Bonneville Power Administration	The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1: – Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL. – Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6. – Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC". Excerpt from the Summary Consideration of question six of the Comment Report Form for 3rd Draft of MOD-001; 2nd Draft of MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 - Project 2006-07: "[MOD-030-1] was modified to state that entities were required to use the provided formula to calculate ATCs and TTCs if they were doing such a conversion, but that the standards did not actually require the conversion." In Order 890 P 211, Order 890-A P 41 and 51, and Order 639 P 1031, FERC clearly indicated that the requirement to convert AFC to ATC is an OASIS posting requirement. In order to ensure that transmission providers were consistent in how AFC was converted to ATC, FERC directed NERC to develop a standard conversion formula. The use of "ATC" and the omission of "AFC" in MOD-001 could be interpreted to require conversion.
Response: The Drafting Team modified the standard to ensure that MOD-001 does not require the conversion from AFC to ATC, as it does not seem to serve a reliability purpose. Note that similar comments have been grouped and responded to once.	
Calpine Corporation	The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose. We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if it is not yet determined which parties will have access to the document. Furthermore, while flexibility is necessary in order to create a standard with applicability across many jurisdictions, allowing undue flexibility as long as assumptions are captured in the ATCID cannot assure market participants of a sufficient degree of standardization.
Response: The standard in R4 and R5 specifies the reliability entities to which the ATCID will be supplied, and NAESB is responsible for determining which information will be shared with market participants. While the standard does promote enhanced transparency, the purpose has been reworded to focus more on the reliability aspects of the standard. The Drafting Team believes that the standard provides an	

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appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation.	
CenterPoint Energy	ERCOT's filed comments to the SDT that ATC, TTC, CBM, and TRM are not applicable within ERCOT operations and that these Standards should have provisions that make it clear that these requirements apply only within market structures in which they are pertinent were ignored by the SDT. These standards should not apply to ERCOT, thus our negative vote.
Response:	MOD-001 has R1 that requires Transmission Operators to select a methodology based on ATC Paths, which have now been defined to be any path for which ATC is already calculated or any path that is a Posted Path, as defined by FERC. Assuming ERCOT does not calculate ATC and has no directive to do so, MOD-001 R1 (and therefore also R2, R6, R7, R8) would not be applicable to ERCOT. R3, R4, and R5 will apply to ERCOT, but the requirements are documentation related and do not seem to be onerous. R9 is intended to support neighboring entities, and ERCOT is expected to comply with this requirement.
City of Tallahassee	Calculating/reporting requirements are too burdensome for smaller systems with little or no real TTC (or ATC) for posting. This standard will require substantial commitment of resources to implement with little benefit to the TP or the surrounding grid.
Response:	The Drafting Team has reviewed the quantity of ATCs that were required in R2 and has changed the requirement from 168 Hourly values to 48 Hourly values. It is necessary for reliability to know the hourly information for the next 1-2 days. However, while OASIS posting is required for 168 hours, the Drafting Team does not see any reliability benefit to calculating more than 48 hours of Hourly data. Daily values provide the necessary reliability information for time periods more than 48 hours in the future.
Dominion Resources, Inc.	In support of PJM comments
Response: Please see response to PJM.	
Dominion Resources, Inc.	Support comments provided by PJM
Response: Please see response to PJM.	
Electric Power Supply Association	The former NERC standard for ATC required that TSPs have and publish their methodology for calculation of ATC. Such a standard has clearly been rejected by FERC, instead opting for much greater transparency. However, we note that amongst the redlined changes in the version of MOD-001 that is being balloted, the word "transparency" has been deleted from the purpose. We also note that Requirement R3.1 requires that sufficient data will be exchanged to allow for validation of the ATC calculation but in response to EPSA and many others it is clear that NERC will not mandate what if any of this data will be shared with market participants. By deferring that question to NAESB, it makes it very difficult for market participants to evaluate whether this standard provides sufficient transparency. The notion of an ATCID document is a positive step. To have a single document with a comprehensive list of assumptions represents a substantial improvement over the status quo. However, the utility of this document is difficult to evaluate if

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Response: The standard in R4 and R5 specifies the reliability entities to which the ATCID will be supplied, and NAESB is responsible for determining which information will be shared with market participants. The Drafting Team believes that the standard provides an appropriate balance between flexibility and standardization. Where possible, the next posting will provide the links to available draft NAESB documentation.	
Florida Municipal Power Agency	We believe this standard needs an additional commenting period.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
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FirstEnergy Energy Delivery	FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below. CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc. Response: Please see responses contained in the CBM and TRM comment reports. FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both. Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct. DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was

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	near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives. Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions: – We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as market areas. In these situations, it is not practical for a TOP to be selecting an ATC methodology. Additionally, per Requirement R1 the standard allows for the selection of different ATC methodologies for each ATC Path for various time periods. Response: Since these standards only deal with the 13 month timeframe, the Drafting Team does not agree that the Planning Coordinator is appropriate. In addition, the Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. The Transmission Operator has the ability to delegate the responsibility to the Transmission Service Provider if desired. – Although we agree with allowing for three different methodologies to match the way different areas of the bulk electric system perform ATC calculations, throughout a single area one specific ATC methodology should be used for all of the paths and time periods. This would result in more consistent ATC calculations. At minimum, it is expected that all participants within a market area would conform to a single ATC methodology. Response: The Drafting Team disagrees. The Drafting Team has seen specific examples where there are valid reasons to use different methods internally versus on external interfaces. Seams management may result in needs for different methodologies on external interfaces than those used for internal paths. In addition, there are valid reasons for using different methods for different timeframes. For example, timeframes that are farther out allow for a more computationally intensive method than can be used in a shorter timeframe. – The standard should be clear on how often and what periodicity the ATC methodology is chosen. It would be a reasonable expectation for an entity to use a given methodology for a minimum period of time before a different methodology can be chosen. FE suggests that the methodology be chosen on an annual basis, or even less often if the team feels that would be appropriate. Response: The Drafting Team does not believe it is appropriate for the standards to define how long a selected method

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	must be utilized. The ATCID must be updated and distributed before any change in method is applied. Also, there are business processes and software requirements involved such that it is not likely that entities will alternate between methodologies. – With regard to Requirement R6, this requirement requires the TSP and TOP to provide consistent ATC calculations based on assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. This requirement is aimed at the calculation (end result), which is the responsibility of the TSP and FE believes it is appropriate to remove the TOP from this requirement. Response: R6 (and its corresponding Measure and VSL) was separated into two requirements to address the specific aspects applicable to the Transmission Service Provider and the Transmission Operator. – The TOP's requirement for providing support via modeling data for use by the TSP is already addressed in the applicable methodology standard (for example, refer to R3 of MOD-030). Response: The Drafting Team agrees that MOD-028, MOD-029, and MOD-030 include details with the Transmission Operator responsibilities, but this requirement is addressing the consistency of assumptions and is common to all three MODs, so it is located in MOD-001.
FirstEnergy Solutions	FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. We offer the following general comments in addition to our specific standard comments presented below. CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc. FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both. Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct. DECISION TO BALLOT: While the MOD standards presented are improving in content FE believes the standards should have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve

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FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:

– We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as market areas. In these situations, it is not practical for a TOP to be selecting an ATC methodology.

– Additionally, per Requirement R1 the standard allows for the selection of different ATC methodologies for each ATC Path for various time periods. Although we agree with allowing for three different methodologies to match the way different areas of the bulk electric system perform ATC calculations, throughout a single area one specific ATC methodology should be used for all of the paths and time periods. This would result in more consistent ATC calculations. At minimum, it is expected that all participants within a market area would conform to a single ATC methodology.

– The standard should be clear on how often and what periodicity the ATC methodology is chosen. It would be a reasonable expectation for an entity to use a given methodology for a minimum period of time before a different methodology can be chosen. FE suggests that the methodology be chosen on an annual basis, or even less often if the team feels that would be appropriate.

– With regard to Requirement R6, this requirement requires the TSP and TOP to provide consistent ATC calculations based on assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. This requirement is aimed at the calculation (end result), which is the responsibility of the TSP and FE believes it is appropriate to remove the TOP from this requirement.

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CBM & TRM - MARKET AREAS: FE supports the drafting team's approach of three ATC methodologies presented in MOD-028, MOD-029 and MOD-030 to account for differences in calculating ATC in various geographic areas of the bulk electric system. However, the use of a single standard methodology for CBM and TRM as currently written does not meet the needs for entities operating within a market area such as MISO, PJM etc. FE suggests that various requirements in the proposed standards that are currently applicable to the TP and TOP are actually handled by the RTO and within a market area would more appropriately be assigned to the Planning Coordinator (PC) and Reliability Coordinator (RC), respectively. This change would allow the proposed standards for CBM and TRM to be used largely "as is" within both market and non-market areas as the PC and RC would be appropriate in both.

Our comments below on specific MOD standards elaborate on this point and provide examples where we feel the applicability is inappropriately assigned to TP or TOP responsible entities within a transmission market construct.

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<tr><td></td><td>have been issued for one more comment period prior to ballot per the NERC Standard Development Procedures (SDP). In many cases this is only the 2nd draft version being reviewed by industry. The objective during the "Solicit Public Comments on Draft Standard (Step 6)" of the NERC SDP is to "Receive stakeholder inputs on the draft standard for the purpose of assessing consensus on the draft standard, and modifying the draft standard as needed to improve consensus." Based on the 200+ pages of comments of the prior draft version it is hard to conclude that the industry was near consensus. Additionally, per the SDP, now that the standards have gone to First Ballot (Step 9), the standard drafting team is not permitted to make any changes to the standards based on comments received during this First Ballot. The drafting team will now be required to rely on their responses to industry feedback to try and improve consensus during a re-circulation ballot. FE has concerns with the consequences of this decision with regard to the integrity of the standard development process and substantive registered entity perspectives.

FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's ATC Standard Drafting Team. However, at this time, FE is voting Negative to this standard with the following comments and suggestions:
– We do not agree with the Transmission Operator (TOP) having the ultimate responsibility in selection of the ATC methodology. This should be the responsibility of either the Planning Coordinator (PC) or Transmission Service Provider (TSP). This is especially true when a TSP is providing service that crosses multiple TOP systems such as market areas. In these situations, it is not practical for a TOP to be selecting an ATC methodology.
– Additionally, per Requirement R1 the standard allows for the selection of different ATC methodologies for each ATC Path for various time periods. Although we agree with allowing for three different methodologies to match the way different areas of the bulk electric system perform ATC calculations, throughout a single area one specific ATC methodology should be used for all of the paths and time periods. This would result in more consistent ATC calculations. At minimum, it is expected that all participants within a market area would conform to a single ATC methodology.
– The standard should be clear on how often and what periodicity the ATC methodology is chosen. It would be a reasonable expectation for an entity to use a given methodology for a minimum period of time before a different methodology can be chosen. FE suggests that the methodology be chosen on an annual basis, or even less often if the team feels that would be appropriate.
– With regard to Requirement R6, this requirement requires the TSP and TOP to provide consistent ATC calculations based on assumptions consistent with those used in any associated operations studies or planning studies for the time period studied. This requirement is aimed at the calculation (end result), which is the responsibility of the TSP and FE believes it is appropriate to remove the TOP from this requirement.
– The TOP's requirement for providing support via modeling data for use by the TSP is already addressed in the applicable methodology standard (for example, refer to R3 of MOD-030).</td></tr>
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– The TOP's requirement for providing support via modeling data for use by the TSP is already addressed in the applicable methodology standard (for example, refer to R3 of MOD-030).</td></tr>
<tr><td colspan="2">Response: Please see in-line responses. Note that similar comments have been grouped and responded to once.</td></tr>
<tr><td>Great River Energy</td><td>GRE supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period based on the significance of the comments submitted during the previous commenting periods.</td></tr>
<tr><td colspan="2">Response: The Drafting Team will be sending the standards out for another round of comments prior to continuing the balloting process</td></tr>
<tr><td>Georgia Power Company</td><td>We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.</td></tr>
<tr><td colspan="2">Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.</td></tr>
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<tr><td>Hydro One Networks, Inc.</td><td>Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those</td></tr>
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Entity	Comment
	where such regulatory approval in not required that is, only when all regulatory approvals have been obtained,
Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1 are approved by all applicable regulatory authorities.	
Hydro One Networks, Inc.	Hydro One Networks Inc. is casting a negative vote on the 6 MOD standards (MOD-001, MOD-004, MOD-008, MOD-28, MOD-029 and MOSD-030) We believe there is a fundamental issue related with effective dates, that is, the dates in which Reliability Standards become effective and enforceable. In principle, the effective date of standards must be the same for all jurisdictions in North America. It does not make sense that there is a period of time when a standard is effective only in some jurisdictions while not in others. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that these Standards are effective in some jurisdictions and not others. These Standards should be modified to ensure that they become effective in all jurisdiction at the same time, including those where such regulatory approval in not required that is, only when all regulatory approvals have been obtained.
Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.	
Independent Electricity System Operator	While we are in general support of this substantially improved standard and the efforts of the standards drafting team (SDT) and have voted YES to MOD-001. We nonetheless, believe that the fundamental purpose of these MOD standards, which is to promote a "consistent" and "reliable" application of Available Transfer Capability (ATC) calculations between BA Areas, is being compromised due to the proposed effective dates. In principle, we believe the effective date of all standards must be the same for all jurisdictions in North America. This is particularly important in the MOD Standards in ballot as they have implications on neighboring areas with varying implementation dates.
Response: Based on the need to support data exchange dependencies, the drafting team has modified the language to read as follows: First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.	
Lincoln Electric System	LES supports BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
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Madison Gas and Electric Co.	We support BPA's position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
MidAmerican Energy Co.	I support the BPA position for changes to take AFC to ATC and TFC to TTC conversions out of this standard. I also support the PJM recommendation that this standard needs an additional commenting period.
Response: Please see BPA and PJM responses.	
MidAmerican Energy Co.	Although this standard leaves much to be desired, it is better than the current standard. I hope NERC continues to work towards consistency in the arena of transfer capability.
Response: Thank you for your comments; the Drafting Team will consider them in subsequent revisions to the standards.	
Midwest Reliability Organization	The MRO supports BPA position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
Mississippi Power	We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
New York Independent System Operator	As an initial matter, the NYISO supports, and incorporates by reference, the five "general" objections to proposed standards MOD-001, MOD-004, MOD-008, and MOD-030, that were raised by the PJM Interconnection, LLC in Sections I-V of its February 29 pre-ballot comments. The NYISO also raises these general objections in its comments on proposed MOD standards -028 and -029 notwithstanding the fact PJM intends to abstain from voting on those standards. Specifically: – The proposed standards should have been sent out for comment not pre-ballot posting. Because there are still a number of significant questions about them and because there are instances where the proposed standards may not be broad enough to accommodate alternative means of compliance. Response: The Drafting Team is posting the standards for an industry comment period – The proposed standards are overly detailed. They contain requirements that should be left for "Business Practices" as that term is defined in MOD-001, creating an unnecessary likelihood of conflict with applicable tariffs, rules, procedures and/or market rules. Response: The Drafting Team disagrees that the standards are too detailed and does not understand which requirements you see that would conflict with tariffs or market rules. When these standards are published for comment again, please provide specific suggestions on what you believe should be modified. – The proposed violation risk factors are too severe. None of the ATC standards should have a risk factor beyond

Entity	Comment
	"Lower" under NERC's own violation risk factor definitions, since violations should not be expected to affect the reliability of the bulk power system. Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling. – The proposed violation severity levels are not complete and several proposed levels should be revised to include gradations that reflect the fact that substantial compliance should not be treated as harshly as total non-compliance. Response: Where possible, the VSLs have been broken into graduated levels rather than only one level. The description of how system outages are applied and the requirement to include all of those outages has a high chance of resulting in noncompliance findings that are unreasonable. The NYISO's December 14 Comments on the third draft of the proposed MOD standards explained in detail how ATC serves a fundamentally different purpose and is calculated differently, with respect to interfaces internal to New York, under the NYISO's Commission-approved "financial reservation" transmission model. Under that system, there are no express physical transmission reservations, all desired uses of the grid are accommodated to the extent that customers are willing to pay congestion, i.e., customers' ability to schedule transactions is not limited by a pre-defined amount of ATC. Instead, ATC postings are really "advisory projections" based on schedules calculated by the NYISO's day-ahead and real-time market software. The Commission has granted the NYISO a number of waivers from its OASIS regulations that reflect these differences. The December 14 Comments further explained that the NYISO believed that its form of financial reservation service would fit within the framework of NERC's proposed definitions and standards provided that NERC interpreted them with reasonable flexibility. The NYISO does not believe that there is anything in the latest version of the proposed MOD standards that is inconsistent with this interpretation. The NYISO notes, however, that the latest version of MOD-001 replaces the definition of "Posted Path" with a new term "ATC Path" that is then used throughout the proposed MOD standards. The definition of "ATC Path," i.e., "[a]ny combination of Point of Receipt or Point of Delivery for which ATC is calculated," is broader than the definition of "Posted Path," which is comparable to the definition used in FERC's OASIS regulations. The broader definition has the potential to come into conflict with waivers the NYISO has previously been granted by FERC that exempt it from the requirement to post ATC values beyond the day-ahead period for its internal interfaces.

Entity	Comment
	This potential for conflict was much less significant when the MOD standards were focused on "Posted Paths" because the NYISO's internal interfaces normally would not be counted as Posted Paths. The NYISO respectfully requests that the SDT either return to its use of the term "Posted Path" or that NERC clarify that it will not seek to enforce MOD requirements against entities that have waivers from FERC that conflict with them. Response: The Drafting Team changed the definition from Posted Path to ATC Path because the definition of Posted Path did not completely capture where ATC should be calculated for reliability, and will not be reverting back to the use of Posted Path. The Drafting Team does not understand how the change in use of "ATC Path" versus "Posted Path" will impact the NYISO. If you are calculating ATC for internal paths, it is not clear how this standard will conflict with your current practice. The NYISO has a similar concern with respect to M2 under MOD-001 which assumes that all Transmission Service Providers are required to post ATC beyond the day-ahead period on all of their interfaces. Response: This standard is only discussing the calculation of ATC, not the posting of ATC. The NYISO respectfully asks that NERC clarify that it will not seek to enforce this rule against entities that have FERC waivers of the relevant underlying OASIS regulation. Response: These standards are written for reliability purposes and are not related to OASIS regulations. It is outside the Drafting Team's scope of responsibility to make interpretations on how these standards will be enforced. The December 14 Comments asked the SDT to revise requirements R10.3 through R10.8, and R10.14, which have now been renumbered under R8, or in the alternative, clarify that they do not apply to transmission providers, such as the NYISO, that use financial reservation models and thus will not have the information that the proposed requirements direct them to make available on request. Otherwise, these information requirements would effectively call on the NYISO to perform functions that FERC's waiver orders excuse it from performing and that would serve no purpose under the NYISO model. The SDT has not made the requested clarifications or revisions. The NYISO therefore respectfully renews its request that the SDT do so. Response: R9.1 states "Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider". The Drafting Team believes this addresses the NYISO concern without additional changes being required. Consistent with Sections I above and with PJM's specific comments on this issue, none of the violation risk factors in MOD-001 should have a rating beyond "Lower," the proposed violation severity levels should be reviewed so that they include appropriate gradations, and the requirements that PJM has identified as being overly detailed should be eliminated and the underlying issues left for NAESB or to the individual practices of Transmission Service Providers and other entities. Response: Please see responses above and responses to PJM.

Entity	Comment
Response: Please see in-line responses.	
Orlando Utilities Commission	This standard should contain only 'lower' level VRFs.
Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.	
PJM Interconnection, L.L.C.	– PJM believes no requirement from the set of ATC standards should have an assigned Risk Factor exceeding "Lower". A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling. – The ATC MOD standards should have been sent out for comment not pre-ballot posting. Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes. – PJM believes that the MOD standards go too far in areas that should be covered and addressed by Business Practices (as defined in MOD-001 Definitions). The frequency of postings and frequency of AFC/ATC calculations should be NAESB Business Practices not in NERC standards as reliability based requirements (see specific details for MOD-001 R2 and R7 and MOD-030 R10 in Specific Comments sections below). Not recognizing the clear

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	distinction between the reliability scope to be addressed by these standards and the NAESB business practices could cause inconsistencies in interpretation. Response: The Drafting Team believes that ATC calculations are reliability related. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability entities to plan accordingly. As such, the standards must provide clear requirements on how many and how often the calculations must occur to be measurable. The number of required hourly values was reduced from 168 from 48 to reflect the reliability need for the ATC calculations. The Drafting Team agrees that the frequency of posting should be a NAESB business practice. – NERC states that a VSL defines the degree to which compliance with a requirement was not achieved. The violation severity levels for these draft standards need to be developed with a more graded implementation for several requirements. The VSLs for several requirements do not consistently include the graded degree of achieving compliance. To the extent that reliability and transparency can be maintained in the event that the entity does not meet the measures the VSL is often excessive. Some VSLs do not recognize the potential varying level of non-compliance with the requirement. With these requirements there are several instances where the VSLs should have incorporated the following distinctions: a. Recognizing gross violation of the requirement - for example the entity's program ignores the requirement. b. Recognizing programmatic issues exist with the implementation of the requirement leading failure to meet some of the requirement. For example if only 167 hours of hourly ATC values instead of 168 hours are calculated it would be a violation with a severe sanction indicating that reliability was severely affected. The actual impact being minimal since customers can only reserve hourly ATC for 24 to 48 hours in the future out of the 168 hours. It is clear that the SDT recognized differences in severity levels in some of the requirements such as MOD001 requirement 7. This was accomplished by specifying timeframes and numbers of instances of not meeting the requirements. However the VSLs in several instances throughout the standard(s) do not reflect this approach. The SDT should continue with a more graded implementation of VSLs for: – MOD001-1: o R2, R5, and R6 Requirement 1 The violation risk factor should be "Lower." Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other

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Entity	Comment
	in an Accepted state (that were not pre-confirmed) may be withdrawn by the customer. However, R8 has been modified to remove the term 'confirmed' so that parties may ask for data exchange of additional statuses. ▪ The description of how system outages are applied and the requirement to include all of those outages has a high chance of noncompliance. A suggestion is to add a time duration for how long an outage can be temporarily excluded due to naming or modeling issue. Another exemption would be to block non-critical outages that cause problems arriving at a loadflow solution (see MOD001-R3.7 and MOD030 R5.2). Response: The ATCID is intended to allow entities to document how to handle these scenarios. R3.6 was modified to remove the term 'duration', indicating a more detailed description is required of how outages are handed. o Requirement 6 ▪ This requires the use of assumptions consistent with those used in associated operations studies or planning studies. PJM believes language should be added as follows: Assumptions used in studies not associated with calculating TTC, AFC, and need not be used. Response: This requirement has been separated to clearly address the Transmission Service Provider versus the Transmission Operators responsibilities. In addition, the phrase 'consistent' was replaced with 'no more limiting than'. ▪ The requirement should be modified to recognize allocation processes as acknowledged in R3.6. The allocation process may affect the value of ATC. The intent of the requirement would be met but not the requirement itself as written. Response: The Drafting Team has addressed this issue by modifying that the assumptions shall be 'no more limiting than' rather than 'consistent'. o Requirement 7 ▪ The requirement is a business practice and should be NAESB scope. This requirement also makes no distinction between firm and non-firm service and assumes the reliability risk is the same. Response: ATC is reliability related and as such, these standards must include measurable requirements on how often the values must be calculated to ensure the data is not stale. The VRF is already lower, whether it applies to firm or non-firm, so there is no way to reflect that not meeting this requirement for non-firm may have a lower reliability risk that firm. o Requirement 8 ▪ R8 should not require the entities to supply data that is not specifically part of the ATC calculation. The requirement should state the entity is to provide information in the form that it has been used.

Entity	Comment
	Response: R9.1 (previously 8.1) currently states this. ▪ R8 fifth bullet--PJM believes reservations in "Accepted", as well as, "Confirmed" status should be included. Response: The status of the reservations was removed to allow the requestor to define what status reservations they want to receive
Response: Please see in-line responses.	
Portland General Electric Co.	The SDT made modifications to MOD-030-1 to no longer require conversion of AFC to ATC and TFC to TTC, but failed to make the necessary modifications to MOD-001-1 to reflect the removal of the conversion requirement. BPA would vote "Yes", if the following modifications were made to MOD-001-1: – Change the following Requirements, Measures, and Violation Severity Levels to replace each "ATC" with "ATC or AFC": first use in R2, R2.1-R2.3, R3.1, R3.2.1, R3.3, R3.7-R3.7.2, R7-R.8, M2 (including the three dashes), M7, M8, R2 Severe VSL, R6 Severe VSL, and R7 Lower VSL - Severe VSL. – Change the following Requirements and Measures to include the missing "TFC" term: R6 and M6. – Change the Data Retention requirement in the first dash of 1.3 to replace "ATC" with "ATC or AFC".
Response: Please see response to BPA	
Potomac Electric Power Co.	Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings: – The ATC MOD standards should have been sent out for comment not pre-ballot posting. – Depth of the ATC MOD standards is excessive. – Determining Violation Risk Factors is incorrect. – Determining Violation Severity Levels is incomplete.
Response: Please see response to PJM.	
Public Service Electric and Gas Co.	PSE&G votes NO for the reasons expressed in PJM's comments.
Response: Please see response to PJM.	
Public Service Electric and Gas Co.	PSE&G votes NO for the reasons expressed in PJM's comments.
Response: Please see response to PJM.	
PSEG Power LLC	PSEG Power LLC votes no for the reasons expressed in PJM's comments.
Response: Please see response to PJM.	

Entity	Comment
PSEG Energy Resources & Trade LLC	PSEG Energy Resources & Trade LLC votes NO for the reasons expressed in PJM's ballot.
Response: Please see response to PJM.	
Sierra Pacific Power Co.	While much great work was undertaken by the SDT in preparing this Standard, I am voting Negative on this Standard primarily for two reasons: – First, I disagree with the assertion in this Standard that any of the Requirements are a Reliability matter. As per our previous comments, ATC is a commercial product, a commodity that is offered by transmission service providers, sold to transmission customers, and perhaps traded among such customers. The body of NERC Standards should be restricted to those that have an impact upon the reliability of the Bulk Electric System. Response: The Drafting Team has adjusted the quantity of ATC or AFC data that must be calculated to better reflect the reliability need for the data, such that only 48 hours of hourly values are required instead of 168 hours. While the Drafting Team does agree that the sale of transmission service and that the underutilization of the transmission system is not a reliability issue, the over-scheduling of the transmission system can have significant reliability implications. An overscheduled condition can require operator intervention; ATC or AFC calculations can provide indicators of the effect planned transfers will have on the transmission system and allows the associated reliability entities to plan accordingly. – Second, and related, is that the Violation Risk Factors are incorrect on R1, R2, and R4 at "medium". As the entire Standard pertains only to non-reliability matters, there is no reason for a VRF higher than "lower". Response: The Drafting Team has modified the standard to set all VRFs to Lower. A medium risk factor is appropriate for "a requirement that, if violated, could ***directly*** affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures." A violation of these standards can produce values that indirectly affect the system (i.e., the value may be used in other processes that result in the sale of transmission service), which results in a Lower VRF. The Drafting Team believes that subsequent recalculations of ATC or AFC will help address any incorrect values. Additionally, such a value would be identified and prevented in advance of actual reliability problems by other standards (e.g., SOL or IROL in the FAC standards) as well as the Transmission Operator's existing guidelines and procedures that prevent the Transmission Operator from over-scheduling.
Response: Please see in-line responses.	
Southern Company Services, Inc.	We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making minor changes to the current draft could undermine the integrity of the good work of the drafting team.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
Westar Energy	R2. Should be ONLY one method for each Transmission Provider, not different method for each Transmission Owner. R8. Certain information, i.e. Power flow models will not be supplied to ANY/ALL requestors; R8 should specify "Qualified"

Entity	Comment
	requestors.
Response: The Transmission Operator is responsible for handling the issues on the real-time system. Therefore, the Drafting Team believes the Transmission Operator (not the Transmission Owner) is the appropriate entity to select the methodology, rather than be forced to implement the method selected by the Transmission Service Provider. The Transmission Operator has the ability to delegate the responsibility to the Transmission Service Provider if desired. All entities that can request information in R8 (R9) are NERC registered functional entities and by definition they are all 'qualified' requestors.	
Wisconsin Public Service Corp.	The WPSC supports BPA position, and agrees with the PJM and MISO recommendation that the standard needs an additional commenting period.
Response: The Drafting Team has made changes in response to this ballot and will be soliciting comments from the industry on these changes.	
WPS Resources Corp.	R5 – The ATCID of the Transmission Service Provider should also be publicly available. Making the ATCID only available to TOs, TPs, RC, and Planning Authorities defeats the purpose of the ATCID document - transparency in the implementation of an ATC methodology.
Response: NAESB is responsible for the dissemination of publicly available information.	
Wyoming Public Service Commission	This standard should be read as not preventing the use of ADI or similar enhancements. It should be applied to give maximum flexibility to regional and sub-regional entities in dealing with the particular and sometimes localized challenges of the Western Interconnection.
Response: The Drafting Team does not believe the standard prohibits the use of ACE Diversity Interchange (ADI) or similar enhancements. If Wyoming Public Service Commission believes otherwise, please detail the potential conflicts in future comments.	