NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary Consideration of Comments:

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

1. 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.
2. A more graded approach was applied to the VSLs where appropriate.
3. During the review of the VSLs and Measures, it was determined that the measures for R5, R6, R7, and R8 did not adequately measure compliance with the requirements. The drafting team updated the measures and VSLs to ensure that they captured the need to have accurate and valid numbers used in the requirements.
4. R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS).
5. MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.

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]

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

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td>R2.2 Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction maximum flow that can be simulated. The justification for this wording change stems from system reliability concerns surrounding "future" electrical system changes that would enable a higher transfer on a system that, prior to the system change, could not achieve this flow. A higher TTC would be allowed after the system reliability considerations at the higher TTC have been satisfied.</td></tr>
<tr><td colspan="2">Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS.</td></tr>
<tr><td>CenterPoint Energy</td><td>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.</td></tr>
<tr><td colspan="2">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, and would not require implementation of any methodology, including this standard.</td></tr>
<tr><td>Consolidated Edison Co. of New York</td><td>R1.1.1.2 should allow for the use of equivalents (in lieu of detailed modeling of neighboring areas).</td></tr>
<tr><td colspan="2">Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>Great River Energy</td><td>GRE does not believe that this standard applies in our region.</td></tr>
<tr><td colspan="2">Response: No response required.</td></tr>
<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 neighbouring 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.</td></tr>
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<tr><td></td><td>In addition we offer the following comments to the specific Standard MOD-029: As drafted, the Standard does not permit any equivalent modeling of neighbouring areas (which is permitted in MOD-028-1).</td></tr>
<tr><td colspan="2">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.

MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>Hydro-Quebec TransEnergie</td><td>Requirement 1.1.1.2 asks to model All Transmission Operator areas contiguous its own Transmission Operator area. This requirement is unlike its brothers in MOD-028 and MOD-030 which allow to model with equivalent. We understand that one could interpret the wording of the standard as in fact allowing the modeling with equivalent, but then it shows that the language of the standard is not clear enough.</td></tr>
<tr><td colspan="2">Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>Kansas City Power & Light Co.</td><td>Requirements state that the Transmission Operator performs functions that are currently performed by the SPP Transmission Service Provider for KCPL. Suggest adding "or Transmission Service Provider" after "Transmission Operator" in all requirements so that either entity could perform these tasks.</td></tr>
<tr><td colspan="2">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. The Transmission Operator has the ability to delegate the responsibility to the Transmission Service Provider if desired.</td></tr>
<tr><td>National Grid</td><td>MOD-028 allows for the equivalent representation of radial lines and facilities 161kV or below and the equivalent representation for immediately adjacent and beyond Reliability Coordination areas. This standard, MOD-029 does not allow for this equivalency. We feel that like MOD-028, MOD-029 should have this same equivalency (with clarification of the 161kV).</td></tr>
<tr><td colspan="2">Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>New Brunswick Power Transmission Corporation</td><td>Take exception to the allowance given for any equivalent modeling of neighboring areas.</td></tr>
<tr><td colspan="2">Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>New York</td><td>There is an issue with no allowance for any equivalent modeling of neighboring areas(which is specified in MOD 28-1)</td></tr>
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Entity	Comment
Power Authority	
Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
Northeast Utilities	No allowance for any equivalent modeling of neighboring areas (which is specified in MOD-28-1).
Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
PacifiCorp	PacifiCorp appreciates the work completed to date on MOD-029, Rated System Path Methodology, and the opportunity to continue to participate in the standards development process. In reviewing MOD-029, PacifiCorp has a remaining concern regarding the Severe Violation Severity Level for R7 that reads "The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements" (emphasis added). The calculation for firm ATC in R7 in the version posted for initial ballot includes incrementing firm ATC for firm counterflows. In the Rated System Path Methodology, PacifiCorp does not use counterflows to increment firm ATC because flows change in real time and may not allow additional firm transfer capability in the opposite direction to be relied upon. Taken further, considering scheduling practices for firm transmission reservations additional transfer capability should not be considered firm for either counterflows or counter schedules. Respecting a transmission customer's right to change schedules against a reservation up to 20 minutes before the hour gives little assurance to a transmission customer relying on any incremental transfer capability created in the opposite direction above and beyond the traditional ATC calculation, and as such additional "counter" transfer capability should only be reserved and scheduled as non-firm. The standard language should explicitly allow transmission providers to not include counterflows or counter schedules in their firm ATC calculation. The definition in R7 states that the adjustments for firm counterflows would be as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document described in MOD-001. While R3.2 and R3.3 appear to provide flexibility for the Transmission Service Provider to define how it accounts for counterflows, PacifiCorp's concern is that it does not use counterflows to increment firm ATC. In practice, most transmission providers in the west using the Rated System Path Methodology do not use counterflows as defined in the formula, PacifiCorp is concerned that it would not satisfy the requirement as discussed above and the Transmission Service Provider would be in violation by not using "all elements defined in R7, or used additional elements" (emphasis added). It should be clear that the use of counter schedules would not be interpreted as an "additional element." To alleviate this concern, PacifiCorp recommends two corrections to the proposed standard. 1) that the Severe Violation Severity Level for R7 be modified to read "The Transmission Service Provider did not use all the elements defined in R7 and as specified in the Transmission Service Provider's Available Transfer Capability Implementation Document required in MOD-001, when determining firm ATC, or used additional elements" 2) that the term counterflows in the firm ATC and non-firm ATC calculation included in R7 and R8 respectively, include a footnote or other language notation that states "May be satisfied under the Rated System Path Methodology without

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<tr><th>Entity</th><th>Comment</th></tr>
<tr><td></td><td>the use of counterflows as defined in the Transmission Service Providers ATCID."

With these changes, and assuming no further changes in the standard language elsewhere, PacifiCorp would vote affirmative for this standard. The remaining language in the standard is acceptable to PacifiCorp and appears to align well with the established rating practices for transmission facilities in the Western Interconnection.</td></tr>
<tr><td colspan="2">Response: Your concerns have been addressed in M9 and M10 by adding the highlighted words in the following sentence: Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…).</td></tr>
<tr><td>Potomac Electric Power Co.</td><td>Potomac Electric agrees with the comments of PJM distributed to the ballot body. I will not repeat them here, but do include the headings:
I. The ATC MOD standards should have been sent out for comment not pre-ballot posting.
II. Depth of the ATC MOD standards is excessive.
III. Determining Violation Risk Factors is incorrect.
IV. Determining Violation Severity Levels is incomplete.</td></tr>
<tr><td colspan="2">Response: Please see PJM response.</td></tr>
<tr><td>PP&L, Inc.</td><td>Section R10 ETCnf Calculation of Existing Transmission Commitments for non firm (ETCnf) should only include non firm transmission reservations that have energy scheduled on them during the operating horizon.

Allowing ATCnf to be decremented by non firm pt to pt reservations, without energy schedules, restricts the utilization of external RTO interfaces. Hoarding of ATC by counterparties who purchase the reservation and do not schedule energy is a possibility.

It is also not stated what the definition of "set aside" is as it pertains to NITSnf. Please provide a definition of "set aside".

Again ATCnf should not be decremented by non firm (network service) reservations that are not associated with energy schedules during the operating horizon. The reasons are the same as stated above.</td></tr>
<tr><td colspan="2">Response: The Drafting Team believes that how to account for unscheduled non-firm service in ETC and ATC is an issue to be discussed in NAESB as part of the postback business practice.

“Set aside” is intended to mean the practice of holding capacity for a committed or expected use. The drafting team believes that this aligns with the common definition of the words used.</td></tr>
<tr><td>Public Service Electric and Gas Co.</td><td>PSE&G votes NO for the reasons expressed in PJM's comments.</td></tr>
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Entity	Comment
Response: Please see PJM response.	
Sierra Pacific Power Co.	Voting affirmative with reservation that the VRF's are too high. None should be higher than "lower". These Requirements have zero impact on BES Reliability; they are merely commercial/business practices.
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. However, 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.	
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	Not applicable to SPP
Response: No response needed.	
Independent Electricity System Operator	Unlike MOD-028, this standard does not explicitly state that one can use equivalent models in their analysis. We are voting for this standard only because we interpret that when R1.1 states that "the model utilizes data and assumptions" - the requirement is indicating that creating equivalent models is included as an "assumption" by the TOP that such models are sufficient to represent the respective areas and that there is no need to explicitly state the use of equivalent models similar to MOD-028. We request the STD to provide this clarification in the standard similar to MOD-0028 for the re-circulation ballot. If our interpretation is incorrect, then we are totally against this standard and will cast a negative ballot during re-circulation
Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
ISO New	ISO New England believe this Standard, similar to MOD-028, should allow for equivalence modeling.

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<tr><td>England, Inc.</td><td></td></tr>
<tr><td colspan="2">Response: MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>New York Independent System Operator</td><td>The NYISO's December 14 comments requested that the SDT revise requirements R2.3 and R2.6 of MOD-029, or, in the alternative, clarify that they do not apply to transmission providers, such as the NYISO, that do not offer physical transmission rights based on contract-path reservations. The SDT did not take either of these actions so the NYISO respectfully renews its request.
Response: The drafting team believes the standards are currently drafted correctly.

The December 14 comments also requested that the definition of OS(F) in the ETC calculation algorithms in MOD-029 (R.6 and R.7) be revised to conform to the corresponding definitions in MOD-028 (R.9 and R. 10). The SDT has revised the definitions in MOD-029 to establish that OS(F) elements should be specified in the ATCID but has not made the requested change. The NYISO respectfully renews its request.
Response: In the Rated System Path methodology simultaneous impact to the path is taken into account in the determination TTC, not $OS_{f,}$ (which is a component of ETC).

Consistent with the NYISO's "general" comments submitted in response to MOD-001, none of the violation risk factors in MOD-029 should have a rating beyond "Lower," the proposed violation severity levels should be reviewed so that they include appropriate gradations, and reliability requirements should not be adopted in areas that are better left to NAESB or to the individual practices of Reliability Coordinators, Transmission Operators, Transmission Service Providers and/or Transmission Planners, etc..
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 drafting team also modified many of the VSLs to have more than one level. 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</td></tr>
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Entity	Comment
	entities to plan accordingly. The NYISO's December 14 Comments also explained that it was critically important that the definition of "Existing Transmission Commitments" ("ETC") in MOD-028 and -029 be interpreted flexibly. Many of the variables in the proposed ETC algorithm will not be applicable (or will always have a value of zero) in the NYISO's case. On the other hand, the most important input into the NYISO's ATC calculations is "Transmission Flow Utilization," which is based on the security constrained network powerflow solutions determined by the NYISO's day-ahead and real-time market software. The NYISO described how the OS(F) variable in the proposed ETC algorithm appeared to be broad enough for the NYISO to include Transmission Flow Utilization information when calculating ETC (and thus ATC). The NYISO added that it could provide additional information concerning its market software's computation of Transmission Flow Utilization and its role in the ETC calculation in its Available Transfer Capability Implementation Document ("ATCID"). The NYISO requested further that if its interpretation were incorrect that the MOD-028 and MOD-029 definition of ETC (and/or OS(F)) be revised to expressly allow ISO/RTO market software results, such as the NYISO's Transmission Flow Utilization information, to be considered in ETC calculations. Otherwise, the NYISO's existing method of calculating and posting ATC using market software outputs, which is a core feature of its FERC-approved market design, would be in conflict with NERC's standard. The SDT has subsequently made certain revision to the OS(F) definitions in MOD-028 and -029. None of the revisions responds to the NYISO's comments. Therefore, absent some contrary statement from NERC, the NYISO will assume that it has correctly interpreted the OS(F) definition as sufficiently broad to allow for the inclusion of Transmission Flow Utilization information when calculating ETC and ATC. Response: The SDT does not disagree with NYISO's understanding; however, interpretation of a standard has its own due process established in NERC and NYISO should pursue that process if it wants more certainty. Finally, the NYISO has previously noted that NERC's December request for an extension of time to file the proposed MOD standards described MOD-029 as a methodology used "exclusively" in the Western Interconnection. The December 14 Comments sought clarification that NERC was not proposing to restrict the use of MOD-029 (or MOD-028) to particular geographic regions. The text of the proposed standards is silent on this question. At the same time, NERC's March 3 Standards Announcement referred to MOD-028 and -029 as being "performed primarily" in the Eastern and Western Interconnections respectively, with no suggestion that either methodology is "exclusive" to those regions. Therefore, absent a statement to the contrary by NERC, the NYISO will assume that there are no geographic restrictions on a Transmission Service Providers' ability to adopt MOD-029 (or MOD-28) Response: NYISO is correct none of the standards are restricted to a geographic region. Further, any Transmission Service Provider can choose any of the methodologies. Refer to MOD-01 R.1. and footnote 1 for R.1
Response: Please see in-line responses.	
PJM Interconnection,	While PJM will not choose the method specified in MOD-029 PJM believes changes needed to make MOD-030 acceptable would cause the need for changes to similar requirements in MOD-029.

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<tr><td>L.L.C.</td><td></td></tr>
<tr><td colspan="2">Response: The Drafting Team has endeavored to make MOD-029 consistent with any changes made to MOD-030.</td></tr>
<tr><td>Alabama 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>
<tr><td>Bonneville Power Administration</td><td>R2.2 Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the maximum flow that can be simulated.</td></tr>
<tr><td colspan="2">Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS.</td></tr>
<tr><td>Consolidated Edison Co. of New York</td><td>R1.1.1.2 should be revised to allow for the use of equivalents (in lieu of detailed modeling of neighboring areas).</td></tr>
<tr><td colspan="2">Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.</td></tr>
<tr><td>Dominion Resources, Inc.</td><td>In support of PJM and NPPC comments</td></tr>
<tr><td colspan="2">Response: Please see PJM response.</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>
<tr><td>Gulf 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>
<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 neighbouring areas. The words inserted in the Effective Date of the Standards as well as in the Implementation Plan document permit that</td></tr>
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	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. In addition we offer the following comments to specific Standard MOD-029: – As drafted, the Standard does not permit any equivalent modeling of neighboring areas (which is permitted in MOD-028-1).
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. MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
MidAmerican Energy Co.	I believe this standard will not apply to us.
Response: No response needed.	
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 Power Authority	MOD-029-1--recommendation to vote NO not to accept NPCC RSC has an issue with no allowance for any equivalent modeling of neighboring areas (which is specified in MOD-28-1).
Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
Public Service Electric and Gas Co.	PSE&G votes NO for the reasons expressed in PJM's comments.
Response: Please see PJM response.	
Madison Gas and Electric Co.	We believe the standard does not apply to MRO members.
Response: No response needed.	
Bonneville Power Administration	I vote yes but suggest that R 2.2 be reworded as follows: R2.2 "Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction maximum flow that can be simulated."

Entity	Comment
	The justification for this wording change stems from system reliability concerns surrounding "future" electrical system changes that would enable a higher transfer on a system that, prior to the system change, could not achieve this flow. A higher TTC would be allowed after the system reliability considerations at the higher TTC have been satisfied.
Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS.	
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. In calculating the ATC or AFC as applicable, a significant factor in the calculations will be the assumed counterflows and postbacks. The standards provide no guidance on these terms, but rather leave them entirely to the discretion of the TSP, subject only to documentation of their assumptions in the ATCID, which might not be visible to market participants.
Response: 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.	
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

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Allowing ATCnf to be decremented by non firm pt to pt reservations, without energy schedules, restricts the utilization of external RTO interfaces. Hoarding of ATC by counterparties who purchase the reservation and do not schedule energy is a possibility. It is also not stated what the definition of "set aside" is as it pertains to NITSnf.
Please provide a definition of "set aside".
Again ATCnf should not be decremented by non firm (network service) reservations that are not associated with energy schedules during the operating horizon. The reasons are the same as stated above.</td></tr>
<tr><td colspan="2">Response: The Drafting Team believes that how to account for unscheduled non-firm service in ETC and ATC is an issue to be discussed in NAESB as part of the postback business practice. “Set aside” is intended to mean the practice of holding capacity for a committed or expected use. The drafting team believes that this aligns with the common definition of the words used.</td></tr>
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<tr><td colspan="2">Response: Please see PJM response.</td></tr>
<tr><td>Barry Green Consulting Inc.</td><td>Transparency: 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 standard that is being balloted, the word "transparency" has been deleted from the purpose.
We also note that a requirement that sufficient data be exchanged to allow for validation of the ATC calculation is included 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.
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Response: 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.	
Bonneville Power Administration	R2.2 Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the maximum flow that can be simulated. The justification for this wording change stems from system reliability concerns surrounding "future" electrical system changes that would enable a higher transfer on a system that, prior to the system change, could not achieve this flow. A higher TTC would be allowed after the system reliability considerations at the higher TTC have been satisfied.
Response: MOD-029 R2.2 has been modified to account for the situation where the TTC in the direction of prevailing flow is determined through the use of a Special Protection Scheme (SPS). In that case the TTC in the non-prevailing direction will be limited to the greater of the flow that can be simulated in the non-prevailing direction or the TTC that can be achieved in the prevailing flow direction without the use of the SPS.	
Consolidated Edison Co. of New York	R1.1.1.2 should allow for the use of equivalents.
Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
Dominion Resources, Inc.	Support comments provided by NPCC and PJM
Response: Please see PJM response.	
PP&L, Inc.	Section R10 ETCnf Calculation of Existing Transmission Commitments for non firm (ETCnf) should only include non firm transmission reservations that have energy scheduled on them during the operating horizon. Allowing ATCnf to be decremented by non firm pt to pt reservations, without energy schedules, restricts the utilization of external RTO interfaces. Hoarding of ATC by counterparties who purchase the reservation and do not schedule energy is a possibility. It is also not stated what the definition of "set aside" is as it pertains to NITSnf.

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Response: The Drafting Team believes that how to account for unscheduled non-firm service in ETC and ATC is an issue to be discussed in NAESB as part of the postback business practice. “Set aside” is intended to mean the practice of holding capacity for a committed or expected use. The drafting team believes that this aligns with the common definition of the words used.	
PSEG Energy Resources & Trade LLC	PSEG Energy Resources & Trade votes NO for the reasons expressed by PJM in its ballot.
Response: Please see PJM response.	
Commonwealth of Massachusetts Department of Public Utilities	Massachusetts DPU has an issue with no allowance for any equivalent modeling of neighboring areas, which is specified in MOD-028-1.
Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
National Association of Regulatory Utility Commissioners	The standard should provide for equivalent modeling of neighboring systems below a certain level.
Response: : MOD-29 has been modified to reflect the “equivalents” language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	
Wyoming Public Service Commission	Sufficient flexibility should be allowed to regional and subregional planners so that they could, under the right circumstances, seek new and workable ways to accommodate intermittent generation resources when there is actual transmission capacity available but not covered by contracted allocations.
Response: The Drafting Team does not believe the standard prohibits the use of intermittent generation resources. If Wyoming Public Service Commission believes otherwise, please detail the potential conflicts in future comments.	
Midwest Reliability	The MRO believes the standard does not apply to MRO members.

Entity	Comment
Organization	
Response: No response needed.	
Northeast Power Coordinating Council, Inc.	The standard should allow for equivalent modeling of neighboring systems.
Response: : MOD-29 has been modified to reflect the "equivalents" language in MOD-28 (R2.1 & R2.2) and MOD-30 (R3.4) and the corresponding VSLs.	