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 R8, R9, R10, and R11 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.

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
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, and would not require implementation of any methodology, including this standard.	
Consolidated Edison Co. of New York	R2 applies to TOP, but R2.1 refers to RC - why the switch? R2.1 should address TOP.
Response: It is not a switch; R2 and all of its sub-requirements specify how the Transmission Operator will model the Transmission Operator's Reliability Coordinator area and adjacent Reliability Coordinator areas. There is no action for the Reliability Coordinator in R2; R2.1 intends to covers the Reliability Coordinator's area for modeling purposes by the Transmission Operator, not the RC. The drafting team does not believe any change is necessary.	
Duke Energy Carolina	The RC's SOL methodology in FAC-011 is required to include generator contingencies. MOD-028 requires the TO to calculate incremental TTC without exceeding SOLs. If the TTC calculation is performed by scaling generation, then generator contingencies should not have to be considered in addition to the scaling, for the purpose of assuring SOLs are not exceeded.
Response: When scaling generation, you are not simulating a contingency – you are just changing dispatch to simulate a transaction. The SDT does not see a conflict.	
Great River Energy	GRE does nor support this standard. GRE has concerns with the application of the standard for transmission providers that use flowgates.
Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies.	
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 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, In addition we offer the following comments to the specific Standard MOD-028: Requirement R2.1 introduces a threshold for allowing equivalent representation of radial lines and facilities. The chosen value of "161 kV or below" needs justification.
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. The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally	

Entity	Comment
accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired.	
Kansas City Power & Light Co.	Requirements state that the Transmission Operator is to perform 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.
Response: The SDT believes it that in the case described, the Transmission Operator can delegate these functions to their Transmission Service Provider.	
National Grid	The standard allows when calculating TTC, the Transmission Operator shall use a model that contains the equivalent representation of radial lines and facilities 161kV or below. The 161kV seems arbitrary. We would like clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities.
Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired.	
New Brunswick Power Transmission Corporation	Would like clarification on why "161kV or below" was chosen in section R2.1 as being the threshold?
Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired.	
Northeast Utilities	Would like clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities.
Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired.	
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: 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.
Response: Please see PJM response.	
PP&L, Inc.	Confirmed TSR's affect non-firm ATC rather than schedules affecting Non-firm ATC.
Response: Confirmed firm TSR's affect Non-firm ATC and unscheduled firm TSR's affect non-firm ATC consistent with postback processes being developed by NAESB.	
Public Service Electric and Gas Co.	PSE&G votes NO for the reasons expressed in PJM's comments.
Response: Please see PJM response.	
Sierra Pacific Power Co.	Not used as a methodology.
Response: No response needed.	
Southern Company	We applaud the great work of the standard drafting team. While the current version is "workable" by Industry, making

Entity	Comment
Services, Inc.	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.
Western Area Power Administration	No Western office uses the Area Interchange model.
	Response: No response needed.
ISO New England, Inc.	Would like clarification as to why "161 kV or below" is the threshold for equivalence in R2.1.
	Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The 161kV threshold doesn't preclude using a lower threshold for equivalencing if desired.
New York Independent System Operator	In its December 14 Comments, the NYISO asked that requirements R3, R4, and R6 under MOD-028 be revised so that TTC would not have to be recalculated when the underlying TTC inputs have not changed. The SDT did not make this revision even though it accepted a similar proposal with respect to the ATC recalculation frequency requirements in what is now R7 under MOD-001 (which the NYISO supports). The NYISO respectfully renews its request that the STD make the requested changes to MOD-028. Under the NYISO system, TTC values do not change often. Accordingly, the proposed MOD-028 requirements would force the NYISO to adopt costly compliance measures that would offer no benefit to its customers. Response: The drafting team did modify requirement R6 under MOD-028 and changed "calculate" to "establish" the TTC values, which allows TTC not to be recalculated when the underlying TTC inputs have not changed but allows the same values with a different time stamp. The drafting team did not modify requirement R3 or R4 under MOD-028 because R3 and R4 do not have any frequency requirements and deal with what is required when TTC is calculated. Consistent with the comments provided for MOD I, all of the violation risk factors in MOD-028 should have a rating beyond "Lower," the proposed violation severity levels should be reviewed to ensure 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 has 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

Entity	Comment
	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. 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.
Response: Please see in-line responses.	
PJM Interconnection, L.L.C.	While PJM will not choose the method specified in MOD-028 PJM believes changes needed to make MOD-030 acceptable would cause the need for changes to similar requirements in MOD-028.
Response: The Drafting Team has endeavored to make MOD-028 consistent with any changes made to MOD-030.	
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.	
Consolidated Edison Co. of New York	R2 applies to TOP, but R2.1 refers to RC - why is there a switch from TOP to RC? R2.1 should address TOP.
Response: It is not a switch; R2 and all of its sub-requirements specify how the Transmission Operator will model the Transmission Operator's Reliability Coordinator area and adjacent Reliability Coordinator areas. There is no action for the Reliability Coordinator in R2; R2.1 intends to covers the Reliability Coordinator's area for modeling purposes by the Transmission Operator, not the RC. The drafting team does not believe any change is necessary.	
Dominion Resources, Inc.	In support of PJM comments
Response: Please see PJM response.	
Florida Municipal	Many small Transmission Operators are network service customers of, and are wholly enclosed by, a much larger

<table>
<tr><th>Entity</th><th>Comment</th></tr>
<tr><td>Power Agency</td><td>TOP/TSP. They have no viable paths or customers in and of themselves and currently their neighboring TOP/TSP handles all of the ATC-related data and calculations mentioned in this standard. In its current draft, this standard puts the onus of calculating TTC squarely on them, when in fact they are not the most appropriate entity for this task. We would suggest changing the Applicability section of this standard (and related standards) to exclude TOP's who are wholly enclosed by a single other TOP, or allow them the choice of deferring to the larger TOP's TTC calculations. We also believe that this standard needs an additional commenting period.</td></tr>
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<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>
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The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The specification of 161 kV doesn't preclude using a lower threshold for equivalencing if desired.</td></tr>
<tr><td>MidAmerican Energy Co.</td><td>The Transmission Service Provider should be allowed to post contract path quantities for CA to CA paths when reliability means are met with flowgates with ATCs calculated in accordance with MOD-030-1.</td></tr>
<tr><td colspan="2">Response: These standards don't attempt to mandate what may or may not be posted. The Drafting Team is also not clear on what the specific question or comment is with regards to the MOD 28 standard. If we have not answered your questions please rephrase it so that we can respond to it in the upcoming comment period.</td></tr>
<tr><td>Mississippi Power</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>
</table>

Entity	Comment
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	4) MOD-028-1--recommendation to vote YES to accept, but would like a clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities.
Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The specification of 161 kV doesn't preclude using a lower threshold for equivalencing if desired.	
Orlando Utilities Commission	This standard should not include any VRF's with a rating above '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.	
Public Service Electric and Gas Co.	PSE&G votes NO for the reasons expressed in PJM's comments.
Response: Please see PJM response.	
Wisconsin Public Service Corp.	WPSC does not support this standard. Certain MRO members have concerns with the application of the standard for transmission providers who use flowgates.
Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies.	
Florida Municipal Power Agency	Many small Transmission Operators are network service customers of, and are wholly enclosed by, a much larger TOP/TSP. They have no viable paths or customers in and of themselves and currently their neighboring TOP/TSP handles all of the ATC-related data and calculations mentioned in this standard. In its current draft, this standard puts the onus of calculating TTC squarely on them, when in fact they are not the most appropriate entity for this task. We would suggest changing the Applicability section of this standard (and related standards) to exclude TOP's who are wholly enclosed by a single other TOP, or allow them the choice of deferring to the larger TOP's TTC calculations. We also believe that this standard needs an additional commenting period.
Response: The Drafting Team has modified the definition of ATC path, which may address some of your concerns. Additionally, Transmission Operators may delegate tasks to other parties.	
Madison Gas and Electric Co.	The MRO does not support this standard. Certain MRO members have concerns with the application of the standard for transmission providers that use flowgates.
Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies.	
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

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	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: Response: 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.	
Duke Energy	The RC's SOL methodology in FAC-011 is required to include generator contingencies. MOD-028 requires the TO to calculate incremental TTC without exceeding SOLs. If the TTC calculation is performed by scaling generation, then generator contingencies should not have to be considered in addition to the scaling, for the purpose of assuring SOLs are not exceeded.
Response: When scaling generation, you are not simulating a contingency – you are just changing dispatch to simulate a transaction. The SDT does not see a conflict.	
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 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. 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	

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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	Many small Transmission Operators are network service customers of, and are wholly enclosed by, a much larger TOP/TSP. They have no viable paths or customers in and of themselves and currently their neighboring TOP/TSP handles all of the ATC-related data and calculations mentioned in this standard. In its current draft, this standard puts the onus of calculating TTC squarely on them, when in fact they are not the most appropriate entity for this task. We would suggest changing the Applicability section of this standard (and related standards) to exclude TOP's who are wholly enclosed by a single other TOP, or allow them the choice of deferring to the larger TOP's TTC calculations. We also believe that this standard needs an additional commenting period.
Response: The Drafting Team has modified the definition of ATC path, which may address some of your concerns. Additionally, Transmission Operators may delegate tasks to other parties.	
PPL Generation LLC	Confirmed TSR's affect non-firm ATC rather than schedules affecting Non-firm ATC.
Response: Confirmed firm TSR's affect Non-firm ATC and unscheduled firm TSR's affect non-firm ATC consistent with postback processes being developed by NAESB.	
PSEG Power LLC	PSEG Power LLC votes no for the reasons expressed in PJM's comments.
Response: Please see PJM response.	
Barry Green Consulting Inc.	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 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. We would be concerned if these values are unduly conservative.
Response: 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.	
Consolidated Edison Co. of New York	R2 applies to TOP but R2.1 refers to RC, R2.1 should address TOP.
Response: R2 and all of its sub-requirements specify how the Transmission Operator will model the Transmission Operator's Reliability	

Entity	Comment
Coordinator area and adjacent Reliability Coordinator areas. There is no action for the Reliability Coordinator in R2; R2.1 intends to covers the Reliability Coordinator's area for modeling purposes by the Transmission Operator, not the RC. The drafting team does not believe any change is necessary.	
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 comment, the drafting team will continue its work in developing reliability standards.	
PP&L, Inc.	Confirmed TSR's affect non-firm ATC rather than schedules affecting Non-firm ATC.
Response: Confirmed firm TSR's affect Non-firm ATC and unscheduled firm TSR's affect non-firm ATC consistent with postback processes being developed by NAESB.	
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	The Massachusetts DPU would like a clarification as to why "161kV or below" was chosen in section R2.1 for being the threshold for allowing equivalent representation of radial lines and facilities.
Response: The 161kV threshold was chosen based on Drafting Team experience for its potential impact on ATC. 161 kV facilities and above are generally accepted to be responsive to transfers, but the drafting team felt it would be too prescriptive to define which facilities below 161 kV would be responsive. The specification of 161 kV doesn't preclude using a lower threshold for equivalencing if desired.	
Wyoming Public Service Commission	[i] Nothing in this Methodology should prevent the use of diversity interchange (such as ADI) to improve overall grid efficiency. [ii] In R6.3, remove the words "in duration" from the end of the sentence, viz: "provided such outage is expected to last 24 hours or longer in duration." "In duration" is redundant.
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. The Drafting Team has removed the redundant language as suggested.	
Midwest Reliability Organization	The MRO does not support this standard. Certain MRO members have concerns with the application of the standard for transmission providers that use flowgates.
Response: The SDT does not understand the concern expressed. This standard would not apply to entities that elected to use the flowgate methodology. We do not believe there is any conflict between methodologies.	