NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Consideration of Comments on 1st Draft of Standard MOD-030-1 — Network Response Flowgate ATC (Project 2006-07)**

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the first draft of standard MOD-030-1, Network Response Flowgate ATC (Project 2006-07). This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 17 sets of comments, including comments from 83 different people from more than 40 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received from stakeholders, comments from the cooperative effort with NAESB in developing associated business practices, and comments received from FERC staff, the drafting team has significantly redrafted the standard. The changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- Added definitions for the following terms:
  - Flowgate
  - Total Flowgate Capability
  - Available Flowgate Capability
  - Power Transfer Distribution Factor
  - Outage Transfer Distribution Factor
  - Flowgate Methodology
- Changed the title of the standard to just, 'Flowgate Methodology'
- Modified the purpose to clarify that the intent is to support 'consistency and transparency of transfer capability calculations' rather than 'consistency and uniformity of ATC calculations'
- Modified the applicability so that the requirements apply to the Transmission Service Provider and the Transmission Operator – the Planning Coordinator and Reliability Coordinator were removed as applicable entities
- R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. The sub-requirements were removed and added to R2.
- R2 was revised so that instead of he Planning Coordinator and Reliability Coordinator identifying Flowgates based on criteria in R1, the requirement was assigned to the Transmission Operator, and the criteria in R1 (sub-bullets R1.1 through R1.3) were clarified and added to R2. R2 was expanded to include the process for identifying Flowgates.
- R3 – was a requirement to make Flowgates 'publicly available' and this has been deleted. NAESB business practices will address all posting requirements. The NERC reliability standards stop at the point where the data or information is provided to the entity responsible for the posting.

- R4 was deleted from the revised standard. This requirement was assigned to the Transmission Owner and Transmission Planner and required that limits be provided to the Transmission Service Provider for use in determining Total Flowgate Capability. Since the standard was revised and the responsibility for determining TFC is now assigned the Transmission Operator this requirement is no longer needed as the Transmission Operator should already have these limits.
- R5 was a requirement for the Transmission Service Provider to use specific thermal limits in the determination of TFC. This requirement was merged into R2 and is assigned to the Transmission Operator. (See R2.3 in the revised standard.)
- R6 was deleted from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.
- R7 was a requirement for the Transmission Service Provider to use specific voltage and stability limits in the determination of TFC. This requirement was merged into R2 and is assigned to the Transmission Operator. (See R2.3 in the revised standard.)
- R8 was a step in the determination of TFC and had been assigned to the Planning Coordinator and Reliability Coordinator. In the revised standard this requirement is assigned to the Transmission Operator (see R2.3 in the revised standard)
- R9 required the Planning Coordinator and Reliability Coordinator to ensure TFCs were calculated in accordance with various time periods. In the revised standard, the Transmission Operator is responsible for calculating TFCs. (see R2.4 in the revised standard)
- R10 required the Planning Coordinator and Reliability Coordinator to distribute their TFCs, and in the revised standard this requirement is assigned to the Transmission Operator. (see R2.5 in the revised standard)
- R11 required public posting of TFCs and this requirement has been deleted from the revised standard. All ATC-related posting requirements are being addressed by NAESB in business practices.
- R12 was a requirement to calculate AFC at specific intervals and this is now addressed in MOD-001 — Available Transfer Capability.
- R13 was a requirement to determine Firm AFC and this has been revised to add more specificity. In the revised standard this is R8 and includes a specific algorithm for determining Firm AFC, with each element of the algorithm clearly defined.
- R14 identified the 'inputs' to use to determine the impact of firm ETC and this has been revised to require the calculation of the impact of firm ETC based on specific time periods. Much more specificity has been added to the description of this process. See R6 in the revised standard.
- R15 required the Transmission Service Provider to limit the total impact of all transmission service from a specific resource to not exceed the sum of the nameplate ratings of all generators at that source. The drafting team could not find a reliable approach to specifying how this could be implemented and the requirement was deleted.
- R16 was modified such that the 3% specified for including third party impacts applies only to 1st tier TSPs and those TSPS with which coordination agreements have been

executed. The elements of this requirement have been moved into R6 and R7 in the revised standard.

- R17 identified a process for calculating non-firm AFC and this has been revised. In the revised standard the process has been converted into an algorithm with each element in the algorithm clearly defined. See R9 in the revised standard.
- R18 identified the 'inputs' to use to determine the impact of non-firm ETC and this has been revised to require the calculation of the impact of ETC on non-firm commitments. See R6 in the revised standard.
- R19 and R20 required specific criteria be met in the modeling of the source and sink, and these requirements were merged into the modeling requirements for the Transmission Service Provider's calculation of AFC. See R4 in the revised standard.
- R21 was a requirement to make AFC calculation results 'publicly available' and this requirement has been deleted from the revised standard because it is being addressed by NAESB in a business practice.
- R22 was a requirement to convert AFC to ATC and this has been modified so that in the revised standard, the process for this conversion is addressed with an algorithm where each element of the algorithm is clearly defined. See R 10 in the revised standard.
- R23 was removed because the release of unscheduled Transmission Service for resale will be addressed by NAESB.
- R24 was a requirement to make ATC 'publicly available' and this requirement has been deleted from the revised standard because it is being addressed by NAESB in a business practice.
- Measures and compliance elements were added.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

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 Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G2) | AESO | | ✓ | | | | | | | | |
| 2. | Jason Murray (G6) | AESO | | ✓ | | | | | | | | |
| 3. | Darrell Pace (G4) | Alabama Electric Coop. Inc | | | | ✓ | ✓ | ✓ | | | | |
| 4. | Helen Stines (G4) | Alcoa Power Generating Inc. | | | | | | ✓ | ✓ | ✓ | | |
| 5. | Ken Goldsmith (G3) | ALT | ✓ | | | | ✓ | | | | | |
| 6. | Eugene Warnecke (G4) | Ameren | | | ✓ | | | ✓ | | | | |
| 7. | E. Nick Henery (G1) | APPA | ✓ | | | | | | | | | |
| 8. | Jerry Smith (G6) | APS-TP | | | | | | | | | | |
| 9. | Dave Rudolph (G3) | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Steve Tran (G6) | BP TX | | | | | | | | | | |
| 11. | Abbey Nulph (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Abbey Nulph (G6) (I) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Rebecca Berdahl (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | Steve Knudsen (G6) | BPA | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 15. | Charles Mee (G6) | CA Dept Water & Power | | | | | | | | | | |
| 16. | Brent Kingsford (G2) | CAISO | | ✓ | | | | | | | | |
| 17. | Greg Ford (G6) | CISO-TP | | ✓ | | | | | | | | |
| 18. | Don Reichenbach (G4) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | Ed Davis | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | George Bartlett | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 22. | Jim Case | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 23. | Joachim Francois (G4) | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 24. | Narinder K. Saini | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 25. | Steve Myers (I) (G2) | ERCOT | | ✓ | | | | | | | | ✓ |
| 26. | Patricia vanMidde (G6) | FERC Case MRG, Sempra | | | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 27. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 28. | Phil Bowers | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 29. | Richard Kovacs | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 30. | Ross Kovacs (G4) | Georgia Transmission Co. | ✓ | | ✓ | | | | | | | |
| 31. | Joe Knight (G3) | Great River Energy | ✓ | | ✓ | | ✓ | | | | | |
| 32. | Ron Falsetti (I) (G2) | IESO | | ✓ | | | | | | | | |
| 33. | Lou Ann Westerfield (G6) | IPUC-SP | | | | | | | | | | |
| 34. | Charles Yeung (G2) | IRC | | ✓ | | | | | | | | |
| 35. | Matt Goldberg (G2) | ISO New England | | ✓ | | | | | | | | |
| 36. | Brian Thumm | ITC | ✓ | | | | | | | | | |
| 37. | Sueyen McMahon (G6) | LADWP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 38. | Eric Ruskamp (G3) | Lincoln Electric System | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 39. | Michelle Rheault | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 40. | Robert Coish (G3) | Manitoba Hydro EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 41. | Jerry Tang (G4) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 42. | Tom Mielnik (I) (G3) | MidAmerican (MEC) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 43. | Dennis Kimm | MidAmerican (MEC) Trading | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 44. | Larry Middleton (G4) | Midwest ISO | | ✓ | | | | | | | | |
| 45. | Carol Gerou (G3) | Minnesota Power | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 46. | Terry Bilke (G3) | MISO | | ✓ | | | | | | | | |
| 47. | William Phillips (G2) | MISO | | ✓ | | | | | | | | |
| 48. | Jim Castle (G2) | New York ISO | | ✓ | | | | | | | | |
| 49. | Matt Schull (G1) | North Carolina MPA | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 50. | Todd Gosnell (G3) | OPPD | ✓ | | ✓ | | | ✓ | | | | |
| 51. | Brian Weber (G6) | Pacificorp | ✓ | | | | ✓ | | | | | |
| 52. | Alicia Daugherty (G2) | PJM | | ✓ | | | | | | | | |
| 53. | C. Robert Moseley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 54. | David A. Wright (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 55. | G. O'Neal Hamilton (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 56. | John E. Howard (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 57. | Mignon L. Clyburn (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 58. | Phil Riley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 59. | Randy Mitchell (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 60. | Chuck Falls (I) (G6) | Salt River Project (SRP) | ✓ | | | | | | | | | |
| 61. | Al McMeekin (G4) | SC Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 62. | Stan Shealy (G4) | SC Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 63. | Bryan Hill (G4) | SCS- Trans | ✓ | | | | ✓ | | | | | |
| 64. | DuShaune Carter (G4) | SCS -Trans | ✓ | | | | ✓ | | | | | |
| 65. | John Troha (G4) | SERC ATCWG | | | | | | | | | | ✓ |
| 66. | Carter Edge (G4) | SERC RC | | | | | | | | | | ✓ |
| 67. | Bob Schwermann (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 68. | Brian Jobson (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 69. | Dick Buckingham (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 70. | Dilip Mahendra (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 71. | W. Shannon Black (G6) | SMUD | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 72. | Phil Odonnell (G6) | SMUD- Ops | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 73. | Casey Sprouse (G6) | Sr. Term Marketer | | | | | | | | | | |
| 74. | Maria Denton (G6) | SRP | | | | | | | | | | |
| 75. | Terri M. Kuehneman (G6) | SRP System Operation | | | | | | | | | | |
| 76. | Raquel Agular (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 77. | Ron Belval (G6) | Tucson | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 78. | Doug Bailey (G4) | TVA | ✓ | | ✓ | | ✓ | | | | | |
| 79. | Jim Haigh (G3) | WAPA | ✓ | | | | | ✓ | | | | |
| 80. | Raymond Vojdani (G6) | WAPA | | | | | | | | | ✓ | |
| 81. | Mike Wells (G6) | WECC | | | | | | | | | | ✓ |
| 82. | Neal Balu (G3) | WPS | | | ✓ | | ✓ | ✓ | | | | |
| 83. | Pam Oreschnick (G3) | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group

G1 – APPA

G2 – ISO – RTO Standards Review Committee

G3 – MRO Members (MRO)

G4 – SERC Available Transfer Capability Working Group (SERC ATCWG)

G5 – PSC of South Carolina

G6 - WECC MIC MIS ATC Task Force

## Index to Questions, Comments, and Responses

1. Do you agree with the responsible entities described in Requirements four through seven and eleven (R4-R7 and R11)? If "No," please explain why in the comments area.

**Summary Consideration:** Most stakeholders who responded to this question indicated that the applicability section of the standard needed revision. The drafting team has redrafted the standard based on a more in-depth reading of the functional model, and we believe it should address the majority of the concerns expressed by the industry. The applicability section of the standard was modified so that there are no requirements in the revised standard applied to the Reliability Coordinator or the Planning Coordinator – and the Transmission Operator was added as an applicable functional entity.

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | "Planning Coordinator" is not a defined term. **Pleae** correct. |
| **Response:** We have drafted a definition to address this on an interim basis, until the Functional Model Drafting Team addresses it in more detail. According to members of the Functional Model Working Group, the terms 'Planning Authority' and 'Planning Coordinator' are equivalent. | | | |
| APPA | | ☑ | These requirements should be in the FAC series and developed by personnel who are experienced in the determination of flowgates and their limitations. The requirements, as written are requiring improper use of the values stated in the requirements. |
| **Response:** The drafting team drafted a Supplemental SAR and has expanded the membership of the drafting team to address this concern. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** We have drafted a definition to address this on an interim basis, until the Functional Model Drafting Team addresses it in more detail. According to members of the Functional Model Working Group, the terms 'Planning Authority' and 'Planning Coordinator' are equivalent. | | | |
| Entergy | | ☑ | R5 reference to Transmission Operator should be changed to Transmission Owner. |
| **Response:** We have included references to the transmission Owner with regard to Facility Ratings. (See R3 in the revised standard.) | | | |
| ITC | | ☑ | ITC agrees with the requirements, themselves, but disagrees with the responsible entities. The Transmission Owner and/or Transmission Operator should be responsible for determing all limits (thermal, voltage, stability) of the transmission facilities. The TO/TOP may choose to delegate the activities, but the requirements in this Standard have put the responsibility on the wrong entity. The RC should not be involved in the determination of facility limits unless so designated to do so. R4 and R5 are appropriate in that respect, but the others are not. As a Transmission Owner/Operator, ITC would be object to any rating greater than one we would provide. This is a dangerous possibility as currently written particularly if commericial interests could affect reliability considerations. |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** We have revised the standard so that it now requires the Transmission Operator to set TFC, but we have not specified how thermal, voltage, or stability limits are determined. The revised standard does indicate (R3) that the Facility Ratings in the transmission model used to determine AFC must include the Facility Ratings provided by Transmission Owners and Generator Owners. | | | |
| MEC Trading | | | The functional model doesn't necessarily translate to reality so this is hard to answer. |
| **Response:** The drafting team appreciates your comment, and has attempted to redraft the standard based on a more in-depth reading of the functional model. | | | |
| MEC | | ☑ | For R6, R8, R9, R10, R11 the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. Further R1 and R2 should also be revised for this reaons to also refer to the "Transmission Service Provider, the Reliabiltiy Coordinator and/or the Planning Coordinator, as appropriate." |
| **Response:** Most stakeholders who responded to this question and to similar questions for MOD-028 and MOD-029, indicated that the Transmission Operator should calculate TTC/TFC.<br>The drafting team deleted R6 from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.<br>R8, R9, and R10 are all related to the determination and dissemination of TFCs – these requirements had assigned to the Planning Coordinator and Reliability Coordinator and in the revised standard all are assigned to the Transmission Operator (see R2.3, R2.4 and R2.5 in the revised standard)<br>R11 required public posting of TFCs and this requirement has been deleted from the revised standard. All ATC-related posting requirements are being addressed by NAESB in business practices.<br>R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. | | | |
| MRO | | ☑ | The MRO believes that for R6, R8, R9, R10, R11 the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. Further R1 and R2 should also be revised for this reaons to also refer to the "Transmission Service Provider, the Reliabiltiy Coordinator and/or the Planning Coordinator, as appropriate." |
| **Response:** Most stakeholders who responded to this question and to similar questions for MOD-028 and MOD-029, indicated that the Transmission Operator should calculate TTC/TFC. | | | |

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| The drafting team deleted R6 from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.<br>R8, R9, and R10 are all related to the determination and dissemination of TFCs – these requirements had assigned to the Planning Coordinator and Reliability Coordinator and in the revised standard all are assigned to the Transmission Operator (see R2.3, R2.4 and R2.5 in the revised standard)<br>R11 required public posting of TFCs and this requirement has been deleted from the revised standard. All ATC-related posting requirements are being addressed by NAESB in business practices.<br>R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. | | | |
| SERC ATCWG | | ☑ | See answer to #6. |
| **Response:** Please see the response to your comments on question 6. | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** We did not receive IRC comments in response to this question. | | | |
| FirstEnergy | ☑ | | |
| IESO | ☑ | | |
| ISO SC | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |

2. Do you believe that all elements of ETC have been adequately captured in Requirements fourteen and eighteen (R14 and R18)? If "No," please explain why in the comments area.

**Summary Consideration:** The drafting team has re-written the requirement describing how to determine ETC.

| **Question #2** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in the second sub-bullet of R14.<br><br>The "five years or longer in duration" language should be removed from the fifth sub-bullet of R14. due to the fact that this element of Order 890 is only to be implemented by a TSP once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those exisitng Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |
| **Response:** In response to this comment, the drafting team has written a more detailed description of how to determine ETC. R14 has been revised (now R6) to base the impact of Firm Network and native Load Service on peak load forecasts for the applicable periods, which would include load growth. The 'five years or longer in duration' was removed in support of your suggestion. (See R6.2 in the revised standard.) | | | |
| APPA | | ☑ | These requirements are tariff or contract requirements that will be contained in or a part of a regulatory or legal document. Some of these requirements are not a reliability issues since and should be removed. Those statements that want to know the effects of actions that are of a reliability nature will be determined by other functions not the TSP, which just sell transmission capacity. |
| **Response:** The requirement to calculate TFC was revised so that it applies to the Transmission Operator rather than the Transmission Service Provider. | | | |
| BPA | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in the second sub-bullet of R14.<br><br>The "five years or longer in duration" language should be removed from the fifth sub-bullet of R14. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |

<table>
<tr><th colspan="4">Question #2</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>The ninth sub-bullet should include all other impacts and not just the impacts using transmission service to service Native Load or firm Network Integration load. Therefore, "using transmission that serves Native Load or Firm Network Integration Transmission Service" should be deleted.</td></tr>
<tr><td colspan="4">Response: In response to this comment, the drafting team has written a more detailed description of how to determine ETC. R14 has been revised (now R6) to base the impact of Firm Network and native Load Service on peak load forecasts for the applicable periods, which would include load growth.<br>The suggestion for deleting the phrase, 'using transmission that serves Native Load or Firm Network Integration Transmission Service' was adopted. In the revised standard the 'options' have been revised and restarted as elements that must be identified and included in the calculation for determining firm ETC. (See R6.1 in the revised standard)<br>The 'five years or longer in duration' was removed in support of your suggestion. (See R6.2 in the revised standard.)</td></tr>
<tr><td>IESO<br>IRC</td><td></td><td>☑</td><td>R14: It is not clear if the standard requires all inputs to be included in the calculation of the impact of Firm ETC. If so, 2 of bullet points are questionable:<br>• FIRM NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries. (POR not equal to POD) Otherwise they are part of the base-flow calculations - Designated Network Resources (DNRs) serving Native Load (first bullet point). In order to clarify, we could add to the second bullet: "not otherwise included in TRM or CBM or in the impacts of Native Load commitments"<br>• Impact of Ancillary Services not included already in TRM, is very difficult to quantify and include in ETC.<br>R18<br>• Non-Firm ETC calculations use the same base flow based on resources serving native load commitments as Firm ETC Calculations. Non-Firm NITS Reservations (second bullet point) are only explicitly incorporated in ETC if they cross control area boundaries (POR not equal to POD). Otherwise they are part of the base-flow calculations.</td></tr>
<tr><td colspan="4">Response: In response to this comment, the drafting team has written a more detailed description of how to determine ETC. See R6 and R7 in the revised standard.</td></tr>
<tr><td>ERCOT</td><td></td><td>☑</td><td>See IRC comments submitted by Charles Yeung.</td></tr>
<tr><td colspan="4">Response: See the response to IRC's comments.</td></tr>
<tr><td>ITC</td><td></td><td>☑</td><td>It is not clear that any "allocations" of flowgate capacity, such as in the MISO/PJM Seams agreement, are covered here. These allocations, while technically covered by the 2nd to last bullet, need to be addressed by stronger language than a blanket "any other agreements" clause.</td></tr>
<tr><td colspan="4">Response: The reliability standard refers only to the allocation of TTC from an ownership standpoint. It does not address contractual allocations of ATC.</td></tr>
<tr><td>MEC</td><td></td><td>☑</td><td>1. R1.1, R3, R11and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this</td></tr>
</table>

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | information is not made publicly without registration.<br><br>2. R14 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropriate level of " the following inputs.<br><br>3. R16 the impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that there are continuing to exist in the area, pre-contingent flowgates which would be inproperly represented by post-contingent flowgates. The pre-contingent flowgates in the area generally only consider signficant third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent.<br><br>4. R18 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the area to maximize the non-firm offerings in the operating horizon. I suggest wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC."<br><br>5. Either use existing transmission commitments in lower case or else provide a definition for the NERC Glossary. |
| **Response:** 1. The team has removed all requirements that included make data or information, publicly available', as NAESB will address all the posting requirements.<br>2. The term "an appropriate level of" may not allow for an accurate measurement of compliance. We have redrafted this language significantly, which may address your concerns.<br>3. The group has elected to use a 3% threshold, based on the work of the Alliant West TLR Task Force.<br>4. The standard allows for, but does not require, the use of meter data in the components used to determine ETC.<br>5. We have provided a definition of ETC, and each standard (MOD-028, MOD-029, MOD-030) explains the calculation of ETC. | | | |
| MRO | | ☑ | 1. R1.1, R3, R11and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration.<br>2. R14 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs.<br>3. R16 the impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that there are continuing to exist in the MRO area, pre-contingent flowgates which would be inproperly represented by post-contingent flowgates. The pre-contingent flowgates in the MRO generally only |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | consider signficant third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent.<br>4. R18 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the MRO to maximize the non-firm offerings in the operating horizon. The MRO suggests wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC."<br>5. Either use existing transmission commitments in lower case or else provide a definition for the NERC Glossary. |
| **Response:** 1. The team has removed all requirements that included make data or information, publicly available', as NAESB will address all the posting requirements.<br>2. The term "an appropriate level of" may not allow for an accurate measurement of compliance. We have redrafted this language significantly, which may address your concerns.<br>3. The group has elected to use a 3% threshold, based on the work of the Alliant West TLR Task Force.<br>4. The standard allows for, but does not require, the use of meter data in the components used to determine ETC.<br>5. We have provided a definition of ETC, and each standard (MOD-028, MOD-029, MOD-030) explains the calculation of ETC. | | | |
| Entergy | ☑ | | Sub requirements shown as bullets should be changed to numbered subrequirements in R14, R16 and R18. |
| **Response:** Agree. Where a sub-bullet indicated a 'required' performance, the bullet was changed to a numbered item in the revised standard. | | | |
| FirstEnergy | ☑ | | However, the term "Post-backs" is industry jargon and should be replaced with the term "reinstatement" to add clarity. |
| **Response:** We have continued to use the term "post-backs," but have requested that NAESB write its definition. | | | |
| MEC Trading | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |
| SERC ATCWG | ☑ | | |

3. Is the conversion of AFC to ATC adequately described in Requirement twenty-two (R22)? If "No," please explain why in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question. The drafting team has rewritten the requirement describing the conversion to be clearer and provide more detail.
The changes made include the addition of the following algorithm:

$$\text{TC} = \min\{\text{PTC}_1, \text{PTC}_2, \ldots \text{PTC}_n\} \text{ And } \text{PTC}_n = \frac{FC_n}{DF_{np}}$$

**Where:**

**TC** is the Transfer Capability (either 'Available' or 'Total').

**P** is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than 3% on an OTDF Flowgate or PTDF Flowgate.

**$\text{PTC}_n$** is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate *n*.

**$\text{FC}_n$** is the Flowgate Capability ('Available' or 'Total') of a Flowgate *n*.

**$\text{DF}_{np}$** is the distribution factor for Flowgate *n* relative to path *p*.

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | Need to let the expanded SDT review this by personnel knowledgeable in development of AFT and distribution factors |
| **Response:** The SDT was expanded and the revised standard reflects the requested actions. | | | |
| Entergy | | ☑ | The requirement should be worded in simple language to reflect how AFCs are determined rather than an equation that a program can use in developing program. |
| **Response:** We have expanded the details in the standard to better explain the process. Most comments wanted more specific details, and the most effective way of providing those details was in an algorithm. The revised standard includes the algorithm and defines each of the elements in the algorithm – while this doesn't support your specific request, the additional specificity should support the intent of your request. | | | |
| ITC | | ☑ | The conversion of AFC to ATC is covered, but it is not clear. The original SAR for this standard included a white paper with appropriate coversion formulae. Please consult and include the translation equations. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| in the algorithm. | | | |
| MEC | | ☑ | The R22 is inadequate in describing what must be done. It is unclear what path the flowgates are to be converted to. Are the flowgate quantities to be converted into equivalent control area to control area path quantities? Are the flowgate quantities to be converted into flowgate path quantities? If it is the latter, what are the definitions and purposes of the flowgate path quantities? In addition, I do not understand what the benefits are in converting Flowgate AFCs to path AFCs. It seems to be an unnecessary and confusing requirement albeit one in FERC Order 890. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements in the algorithm. Generally transmission service is sold on a path basis, with the limit being the most limiting Flowgate above the threshold limit. | | | |
| Manitoba Hydro | | ☑ | I don't believe there should be a conversion it only leads to uncertainty. I believe that the committee should be able to standardize on one technique. |
| **Response:** Order 890 allows for three methodologies, and the conversion explains how to post the results of one methodology in the terms used by the other two. | | | |
| MRO | | ☑ | The MRO believes that the R22 is inadequate in describing what must be done. It is unclear what path the flowgates are to be converted to. Are the flowgate quantities to be converted into equivalent control area to control area path quantities? Are the flowgate quantities to be converted into flowgate path quantities? If it is the latter, what are the definitions and purposes of the flowgate path quantities? In addition, the MRO does not understand what the benefits are in converting Flowgate AFCs to path AFCs. It seems to be an unnecessary and confusing requirement albeit one in FERC Order 890. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements in the algorithm. Generally transmission service is sold on a path basis, with the limit being the most limiting Flowgate above the threshold limit. | | | |
| SERC ATCWG | | ☑ | The definition provided in the SAR was clearer than the current definition. The new definition introduces new terms into the process that are not industry standard or recognizable. |
| **Response:** We replaced the requirement with a more detailed algorithm that includes a definition of each of the elements in the algorithm. We believe all terms are either in the NERC Glossary or are proposed by the updated MOD Standards. | | | |
| ERCOT | ☑ | | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments | | | |
| BPA | ☑ | | However, for the reasons explained in our response to the MOD-030-1 Comment Form's question 4, BPA suggests that R22. be modified to the following:<br>" The Transmission Service Provider shall make publicly available a mechanism for interested parties to convert Flowgate AFCs to path ATCs based on…" |
| **Response:** FERC has directed that path ATCs be posted. NAESB will be addressing what needs to be posted and how. | | | |
| IESO | ☑ | | Yes, the conversion is described adequately. In the first bullet point, "…the Transmission Service |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Provider shall calculate the partial AFC of that…" should be written as "…the Transmission Service Provider shall calculate the partial ATC of that…" |
| **Response:** The drafting team appreciates your response. You are correct, 'partial AFC should have been partial ATC.' | | | |
| IRC | ☑ | | Yes, conversion described adequate.<br>• Partial AFC should be partial ATC in first bullet point. |
| **Response:** The drafting team appreciates your response. You are correct, 'partial AFC should have been partial ATC.' | | | |
| MEC Trading | ☑ | | |
| PSC SC | ☑ | | |
| FirstEnergy | ☑ | | |

4. Do you anticipate any problems with posting both AFCs and ATCs as described in Requirements twenty-one and twenty-four (R21 and R24) in this draft standard? If "Yes," please explain why in the comments area.

**Summary Consideration:** Most stakeholders who responded to this question indicated that there would be problems in complying with the originally proposed R21 and R24. The drafting team has removed the posting requirements from the standard. NAESB will be addressing what needs to be posted and how in business practices.

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Entergy | | ☑ | AFCs are not required to be posted as these do not mean much to the users, therefore, R21 should be deleted. |
| **Response:** R21 was deleted from the revised standard. NAESB will be making the determination if these need to be posted or not. | | | |
| PSC SC | | ☑ | |
| WECC MIC MIS ATC TF | ☑ | | (The below statement is proposed by BPA. Is the WECC Team OK with supporting it?)<br>Under the flowgate methodology, ATC is a value derived from an analysis of the expected powerflow impacts of a reservation across multiple flowgates. Consequently, it is the posting of AFC and timely posting of changes to AFC that inform whether transfer capability exists to support a request for transmission service. ATC for a POR-POD path is derived from posted AFC. When posting both ATC by path as well as AFC by flowgate, there is a risk that the AFC and ATC values could get "out of sync" due to automation lag-time, etc. BPA believes that greater consistency and transparency is achieved if only AFC values are posted for each flowgate, and requestors are provided with a "conversion calculator" that calculates ATC for their requested path based on posted AFC's. |
| **Response:** FERC has directed that path ATCs be posted. NAESB will be addressing what needs to be posted and how. | | | |
| APPA | ☑ | | This Standard trys to provide detail requirements for AFT, ATC, ETC and the requirements of 3 different functional entities and it is written in a manner that will not support a Compliance program. |
| **Response:** We have redrafted the standards to address this concern. The applicability of the standard was revised and the Planning Coordinator and Reliability Coordinator are not assigned responsibility for any requirements. | | | |
| BPA | ☑ | | Under the flowgate methodology, ATC is a value derived from an analysis of the expected powerflow impacts of a reservation across multiple flowgates. Consequently, it is the posting of AFC and timely posting of changes to AFC that inform whether transfer capability exists to support a request for transmission service. ATC for a POR-POD path is derived from posted AFC. When posting both ATC by path as well as AFC by Flowgate, there is a risk that the AFC and ATC values could get "out of sync" due to automation lag-time, etc. BPA believes that greater consistency and transparency is achieved if only AFC values are posted for each Flowgate, and requestors are provided with a "conversion calculator" that calculates ATC for their requested path based on posted AFC's. |
| **Response:** FERC has directed that path ATCs be posted. NAESB will be addressing what needs to be posted and how. | | | |
| ERCOT | ☑ | | See comment 9. |

| Question #4 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** | | | |
| FirstEnergy | ☑ | | The standard should include specifics of methods for complying with the term "publicly available" such as posting on OASIS, a corporate web page, etc. (This concept is mentioned in all MOD-028, MOD-029, and MOD-030.) |
| **Response:** The SDT has eliminated this language, and will let NAESB specify the manner in which information is to be posted. | | | |
| IESO<br>IRC | ☑ | | R21 and R24<br>Current tools allow the submission of requests and retrieval of available and calculated AFC and ATC data. It is questionable if that is considered being compliant with R21 and R24. If not, changes to the software might be required to meet the requirements of R21 and R24. |
| **Response:** R21 and R24 have been deleted from the revised standard as they were requirements to make information publicly available and NAESB is addressing these requirements in its business practices. | | | |
| ITC | ☑ | | A ridiculous amount of paper or web space will be used if all ATC path values are posted for large footprints. Flowgates can be in the thousands but ATC paths are quadratic functions of the number of Sources/Sinks (i.e., too many paths to print). ATC for a given path should be on request. (i.e., ask for the path and the TSP provides that specific path ATC via OASIS). This should be either through manual entry by the requestor or electronically via a requestor electronic query tool (i.e., computer program query). |
| **Response:** FERC has directed that path ATCs be posted. R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |
| MEC | ☑ | | It will be incredibly confusing posting both AFCs and ATCs for the same transmission service. I agree that this is in accordance with the FERC Order 890; however, I do not understand what the benefits of this conversion to open transmission service and reliability. I ask the SDT to clarify. |
| **Response:** R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |
| MRO | ☑ | | It will be incredibly confusing posting both AFCs and ATCs for the same transmission service. The MRO agrees that this is in accordance with the FERC Order 890; however, the MRO does not understand what the benefits of this conversion to open transmission service and reliability. The MRO asks the SDT to clarify. |
| **Response:** R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |
| SERC ATCWG | ☑ | | Posting the AFC numbers provide no additional value if the ATC numbers are posted. |
| **Response:** R21 and R24 have been deleted from the revised standard. NAESB will be addressing what needs to be posted and how. | | | |

5. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to AFC, as it relates to ATC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to AFC in this draft of MOD-030-1? If "No," please explain why in the comments area.

**Summary Consideration:** The drafting team disagreed with the suggestions regarding FAC-012. Other comments suggested a general concern with a lack of clarity and detail regarding the Order, which is beyond the scope of the drafting teams work.

| **Question #5** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings. FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC. |
| **Response:** We agree the FERC order requires this; however, we believe we have good technical reasons for writing the standard otherwise. | | | |
| Duke | | ☑ | Conditional Firm Service (CFS) and Planning Redispatch Service (PRS) under Order No. 890 create new issues relating to modeling and calculating ATC. Specifically, when PRS is offered to maintain service, modeling for ATC calculations will be impacted during these periods. TTC must be modeled/calculated accounting for the new CFS/PRS requirements. |
| **Response:** Since these concepts have not been fully developed, the standard as drafted allows for the inclusion of CFS and PRS when modeling usage of the system. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| IESO | | ☑ | Note - We don't have a complete overview of all directives to answer this question. |
| **Response:** The drafting team will post a table that includes all relevant directives from FERC Order 693 and 890 to show the standard and requirement that addresses each directive. | | | |
| IRC | | ☑ | Note - Don't have a complete overview of all directives to answer that question. This is time intensive!!!! |

| **Question #5** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The drafting team will post a table that includes all relevant directives from FERC Order 693 and 890 to show the standard and requirement that addresses each directive. | | | |
| MEC Trading | | ☑ | Standard is a fill-in-the-blank |
| **Response:** The SDT has added significant detail to address this concern. | | | |
| FirstEnergy | ☑ | | |
| Entergy | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| PSC SC | ☑ | | |

6. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities to whom you believe the standard should apply and why.

**Summary Consideration**: Most stakeholders who responded to this question indicated that they disagreed with the applicability section of the standard. The SDT made changes to the functional entities based on commenters' suggestions, and the revised standard does not include either the Planning Coordinator or the Reliability Coordinator as responsible entities – and the Transmission Operator has been added as a responsible entity.

The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document – and modified all the standards in this set (MOD-028, MOD-029, MOD-030) to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC.

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF | | | See above on defining Planning Coordinator. |
| **Response:** We have removed the PC from the standard. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** We have removed the PC from the standard. | | | |
| IESO | | ☑ | TSP is the sole entity responsible for performing calculations, and posting of the results. The PC, RC, and TO only submit data to the TSP, such as list of OTDF and PTDF flow gates, seasonal limits of flow gates, flowgate components, flow directions on flowgate components etc. They do not calculate ATC, hence R1 is irrelevant. |
| **Response:** The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document (ATCID)– and modified all the standards in this set to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC.<br>R1 addresses the ATCID and in the revised standard is assigned to the Transmission Service Provider.<br>Note that all posting requirements have been removed from the revised standards. | | | |
| IRC | | ☑ | TSP is responsible to perform calculations, and post the results, the PC and RC and TO only submit data to TSP, such as list of flow gates, limits of flow gates. They do not calculate ATC, hence R1 is irrelevant. |

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| **Response:** The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document (ATCID)– and modified all the standards in this set (MOD-028, MOD-029, MOD-030)to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC.<br>R1 addresses the ATCID and in the revised standard is assigned to the Transmission Service Provider.<br>Note that all posting requirements have been removed from the revised standards. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| ITC | | ☑ | Applicable Entity 4.2 is not appropriate. Reliability Coordinators should not be calculating ATC. According to the Functional Model, ATC Calculations are performed by the Transmission Service Provider (Task #2, "Determine and post available transfer capability values.") R4 and R5 identify the TO and TP as responsible entities, and need to be included in the applicability sections. |
| **Response:** The drafting team modified MOD-001 — Available Transfer Capability to assign the Transmission Service Provider with the responsibility for having an Available Transfer Capability Implementation Document (ATCID)– and modified all the standards in this set (MOD-028, MOD-029, MOD-030) to clarify that the Transmission Operator and Transmission Service Provider are the entities with responsibility for developing the calculations used to determine ATC. The Transmission Operator determines the Transfer Capabilities and the Transmission Service Provider determines ATC. We do not agree that the Transmission Planner is applicable. R4 was deleted from the revised standard as the Transmission Operator will already have these limits – and R5 was merged with other requirements into R2 which is assigned to the Transmission Operator (see 42.3 in the revised standard.) | | | |
| MEC | | ☑ | It is not appropriate to qualify the Functional Entity as provided in A.4.1 through A.4.3, that is, A.4.1 through A.4.3 should just list the NERC functions from the NERC functional model and not qualify it. For example, 4.1 should be "Planning Coordinator" not "Each Planning Coordinator that uses the Flowgate Network Response method to calculate…..". Then it is up to Planning Coordinators etc. to review the standard to see how the requirements are to be applied, if at all. |
| **Response:** The NERC Standards Development Process encourages the qualification of applicable entities to ensure only the appropriate entities are required to adhere to the standard. | | | |
| MRO | | ☑ | The MRO believes it is not appropriate to qualify the Functional Entity as provided in A.4.1 through A.4.3, that is, the MRO recommends that A.4.1 through A.4.3 just list the NERC functions from the NERC functional model and not qualify it. For example, 4.1 should be "Planning Coordinator" not "Each Planning Coordinator that uses the Flowgate Network Response method to calculate…..". Then it is up to Planning Coordinators etc. to review the standard to see how the requirements are to be applied, if at all. |
| **Response:** The NERC Standards Development Process encourages the qualification of applicable entities to ensure only the appropriate entities are required to adhere to the standard. | | | |

| **Question #6** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| SERC ATCWG | | ☑ | The applicability section needs clarification. Referencing R1,6,8,9 and 10 they should apply only to those entities performing the function. The standard should not require the calculations be made by the PC and RC, but should be applicable to the designated entitiy performing these calculations . The designated entity must be specified as a requirement in this standard. For example: The TSP, PC and RC must specify and agree to the entity that performs this function in the TSP's ATCID as required in MOD 1. The current revision of MOD-001 states the following requirement as R1: "Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider." The requirements of MOD-0028 should refer to the Designated Entity specified through this requirement. The following are examples of how this would be implemented in the standard:<br><br>B. Requirements<br>R4. Each Designated Entity shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.<br>R5. Prior to calculating TTC, each Designated Entity shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied: |
| **Response:** We have changed the functional entities referenced to address your concerns.<br>R1 was revised so that, instead of being assigned to the Planning Coordinator and Reliability Coordinator, R1 in the revised standard applies to the Transmission Service Provider to align with the revisions made to MOD-001 – Available Transfer Capability – where responsibility for the Available Transfer Capability Identification Document is assigned to the Transmission Service Provider. Note that MOD-001 was also revised to clarify that the Transmission Service Provider calculates ATC.<br>The drafting team deleted R6 from the revised standard. R6 required the Planning Coordinator ad Reliability Coordinator to provide the Transmission Service Provider with voltage and stability limits – the revised standard assigns the Transmission Operator responsibility for determining TFCs, and assumes that the Transmission Operator already has these limits.<br>R8, R9, and R10 are all related to the determination and dissemination of TFCs – these requirements had assigned to the Planning Coordinator and Reliability Coordinator and in the revised standard all are assigned to the Transmission Operator (see R2.3, R2.4 and R2.5 in the revised standard)<br><br>"Designated Entity" is inappropriate for a responsible entity. The Functional Entity may delegate tasks, but the Functional Entity remains the responsible entity. | | | |

7. In R15, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R15 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

**Summary Consideration:** There was no consensus amongst the stakeholders who responded to this question. The DT discussed this issue in an attempt to define specific requirements to ensure consistent implementation. Several different approaches were discussed; however, talking through examples it was determined that each implementation would have a detrimental impact on either reliability or Open Access. Therefore this requirement was removed. This shall serve as a single response to opinions offered in response to this question.

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IRC | | ☑ | No R15 doesn't meet the intend of paragraph 245. Most of the PtP Reservations don't have specific resources as Source, they typically source from a group of commonly dispatched units. Also most Tariff's allow re-direct of Reservations to different Sources, so excluding Reservations from impact calculations could possibly result in overselling the system if the excluded reservation is re-directed to a different source. It might be possible to make some general guidelines to address the paragraph 245 of Order 890 such as:<br>• Total sum of Reservations (Confirmed, Approved, Study) impacting a specific corridor, such as a DC tie should not exceed the total capacity of the corridor.<br>• Total sum of Reservations (Confirmed, Approved, Study) sinking in a Control Area should not exceed the total Load of the Control Area.<br>• Total sum of Reservations ((Confirmed, Approved, Study) sourcing from a group of commonly dispatched units should not exceed the total available generation capacity of that group of units. |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| ITC | | ☑ | It meets the intent but is subject to potentiallt adverse interpretation. It is true that a POR may not exceed Pmax for the installed generation; however, when multiple requests are received for the POR that exceed Pmax, should the requests be taken first-come-first-served until Pmax is reached? Should the worst-case scenario be studied and used to set limits? Should the requests be pro-rated until the sum of the requests is reduced to Pmax? We believe the TSP should be allowed some leeway in how they model these situations, in order to prevent reliability problems. |
| IESO | | ☑ | No. R15 doesn't meet the intend of paragraph 245. Most of the PtP Reservations don't have specific resources as Source, they typically source from a group of commonly dispatched units. Also most Tariff's allow re-direct of Reservations to different Sources, so excluding Reservations from impact calculations could possibly result in overselling the system if the excluded reservation is re-directed to a different source. It might be possible to make some general guidelines to address the paragraph 245 of Order 890 such as: |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | • Total sum of Reservations (Confirmed, Approved, Study) impacting a specific corridor, such as a DC tie should not exceed the total capacity of the corridor.<br>• Total sum of Reservations (Confirmed, Approved, Study) sinking in a Control Area should not exceed the total Load of the Control Area.<br>• Total sum of Reservations ((Confirmed, Approved, Study) sourcing from a group of commonly dispatched units should not exceed the total available generation capacity of that group of units. |
| MEC | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests to the source point where subsequent requests will result in power being moved away from the point and show how the Transmission Service Provider than reviews the impacts to meet the requirement. |
| MRO | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests to the source point where subsequent requests will result in power being moved away from the point and show how the Transmission Service Provider than reviews the impacts to meet the requirement. |
| FirstEnergy | ☑ | | MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030 |
| **Response:** It was the decision of the SDT, supported by stakeholder comments, that MOD-001 be an overview, while MOD-028,-029-030 are separated to address various methods of calculation of TTC/ATC/AFC. The Order allows for more than one method; the SDT believe this approach is more clear and transparent to the industry. | | | |

| Question #7 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| FirstEnergy | ☑ | | However, the phrase "not exceed" can be replaced with the word "the" since the term "limiting the total impact" is synonomous. |
| MEC Trading | ☑ | | The words meet the intent of the order, but the order may not be technically correct, nor consistent with other OATT requirements. |
| Entergy | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PSC SC | ☑ | | |
| WECC MIC MIS ATC TF | ☑ | | |
| Entergy | ☑ | | |
| PSC SC | ☑ | | |

8. Do you agree with the 3% specified in R16 for including third party impacts? If "No," please specify what percent or alternate approach should be used and explain why in the comment area below.

**Summary Consideration:** The drafting team only received one suggestion for a different threshold (5%); and elected to retain the 3% threshold. The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions.

| Question #8 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC MIC MIS ATC TF<br>BPA | | ☑ | The threshold of 3% appears to be an arbitrary level. This level may be rooted in Operational and Planning studies that consider impacts from outages on one TP's system that increase loading on an element of another TP's system by 3% or more. While this level may be a good indicator of impact, it may not provide an indicator of which party's ownership or allocation of facilities is being used. It does not assure TPs will be able to preserve their rights (i.e. by contractual allocation) with a fixed threshold of 3%. |
| **Response:** The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions. | | | |
| Entergy | | ☑ | The threshold level of 3% for third party should not be included in this standard since there is no such threshold level for Transmission Service Provider's own data. |
| **Response:** We have modified the standard to clarify that providers may use a lower threshold if they wish – see the footnotes added to R7 in the revised standard. | | | |
| IESO<br>IRC | | ☑ | We assume the third party is a 1 tier or 2 tier Control Area adjacent to the Tariff footprint of the TSP. Some questions:<br>• Paragraph talks about impact transmission capability with 3%. Does this mean impact any flow gate within the Tariff footprint of the TSP with 3%. What about flow gates that are tie lines between Tariff footprint and 1tier and limiting element is in 1tier.<br>• What participation factors and generators should be used to determine if the GLDF of commonly dispatched units of 1tier Control Area is >3%. NERC IDC?<br>• Is the data listed in bullet point 2,3,4,5,6 of R16 going to be submitted by neighbor TSP. If so it is sufficient to specify that a TSP is getting the list of Reservations as specified in 2,3,4,5,6 of R16 from a neighboring TSP without having to know detail as specified in the bullet points. |
| **Response:** 1.) We have modified the standard such that the 3% applies to only 1st tier TSPs and those TSPS with which coordination agreements have been executed. We have also defined the criteria for how to select flowgates.<br>2.) The distribution factors should be based on calculating TSP's methodology for determining distribution factors.<br>3.) You will need to filter the data, since the data provided may include information relevant to one party but not another. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See IRC response. | | | |
| MEC Trading | | ☑ | If is this appropriate for MOD-30, it is appropriate for MOD-28. Why do you specifically spell out a |

| Question #8 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | requirement for MOD-30 but not MOD-28? |
| **Response:** The methodologies are different, and different approaches apply. We will look at making them more consistent in future versions. We have added a requirement to MOD-028 to consider third-party reservations. | | | |
| MEC | | ☑ | The impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that pre-contingent flowgates are continuing to exist in the area. Such pre-contingent flowgates have physical conditions that would be improperly represented by post-contingent flowgates so the pre-contingent flowgates must remain in place. The pre-contingent flowgates in the area generally only consider significant those third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent. |
| **Response:** The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions. | | | |
| MRO | | ☑ | The impacts by more than 3% are consistent with post-contingent flowgates. It should be noted that pre-contingent flowgates are continuing to exist in the MRO area. Such pre-contingent flowgates have physical conditions that would be improperly represented by post-contingent flowgates so the pre-contingent flowgates must remain in place. The pre-contingent flowgates in the MRO generally only consider significant those third-party impacts that are at 5% or more. Therefore, provisions should be made in R16 to allow the appropriate screen, 3% or 5%, for the appropriate type of flowgate, post-contingent or pre-contingent. |
| **Response:** The 3% is consistent with the work of the Alliant West TLR Task Force, which performed statistical analyses to determine a more efficient threshold for identifying impacting transactions. | | | |
| Manitoba Hydro | | ☑ | During a TLR or redispatch, a 3% cutoff would require the third party to adjust their resources by up to 33 MW for every 1MW of relief. I believe that this is too much. I would recommend third party mitigation has to be a balance of impact and ability for relief and those 3% biases that balance. I would recommend that the 5% impact which still requires a potential 20 MW adjustment for every 1 MW of relief maintains the balance between impact and ability for relief. |
| **Response:** This requirement addresses what transactions that are included in TSP analyses, and is not directly related to curtailments. | | | |
| ITC | ☑ | | This is overdue in our estimation. Using 5%, as some have done, has resulted in unnecessary TLRs, particularly on lower voltage (138kV and below) systems. |
| **Response:** Thank you for your support. | | | |
| FirstEnergy | ☑ | | |
| PSC SC | ☑ | | |

9. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please describe the conflict in the comments area.

**Summary Consideration:** Most stakeholders who responded to this comment indicated they were not aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. The SDT suggests that ERCOT, and others who believe this standard should not apply to them, pursue a regional difference to address their concerns.

| **Question #9** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| ITC | | ☑ | There are 3 methods, pick the one that works. We have noted in our other comments that some entities, such as New England, have approved tariffs that don't require the sale of transmission service. They should not have to pick any method but should, as we have noted, be required to provide data to neighboring TSPs that do sell transmission service. |
| **Response:** The SDT agrees this is a concern – entities with this concern need to submit a request for a Regional Difference. | | | |
| FirstEnergy | | ☑ | |
| WECC MIC MIS ATC TF | | ☑ | |
| Entergy | | ☑ | |
| MEC | | ☑ | |
| Manitoba Hydro | | ☑ | |
| MRO | | ☑ | |
| PSC SC | | ☑ | |
| ERCOT | ☑ | | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.<br><br>Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. |

| Question #9 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved "beyond" ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therfore both ERCOT and SPP are notified when the DC Tie capability is reduced.<br><br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.<br><br>In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.<br><br>In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Control Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The SDT agrees this is a concern – ERCOT needs to submit a request for a Regional Difference. | | | |

| **Question #9** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MEC Trading | ☑ | | This standard is not requiring consistenecy per the requirement of FERC Order 890. |
| **Response:** Please see the revised set of standards. The drafting team modified all of the standards to require greater consistency between standards. | | | |

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-030-1.

**Summary Consideration:** The SDT made changes in response to some of the comments below, including adding definitions and redrafting sections to be clearer. Note that NAESB will be addressing some of the more commercial areas of the subject matter, such as timing guidelines and posting requirements.

| **Question #10** | |
|---|---|
| **Commenter** | **Comment** |
| WECC MIC MIS ATC TF | A. R1.2 should be modified due to the fact that Facilities don't cause congestion, rather they experience congestion. The following change to the language would be more accurate:<br>"How the methodology identifies transmisison Facilities that are expected by the AFC calculator to experience congestion on the transmission system."<br>B. See comments on MOD-29.<br>In the "Applicability" section, the term "Available Transfer Capability Implementation Document" is used as a defined term. The term is used in MOD-01 R3. At minimum the ATCID either needs to be defined or a reference to the MOD-01 must be inserted for cross reference.<br>C. R.1 through R.3. appear to be a prohibited "fill-in-the-blank."<br>D. R22. Typo. Change "covert" to "convert." |
| **Response:** A. We have redrafted this language, and it is now included in R2.1. (See R2.1.3 in the revised standard.)<br>B. We have defined ATCID.<br>C. We have attempted to address this comment by requiring more detail and making explicit requirements where possible.<br>D. We have corrected this error (See R10 in the revised standard). | |
| BPA | The ATC MOD's (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide descriptions of these methodologies.<br>The Applicability section 4.1. through 4.3. Should have the phrase "Available Transfer Capabilities for paths" replaced with "Available Flowgates Capabilities for Flowgates".<br>R1.2. should be modified due to the fact that Facilities don't cause congestion, rather they experience congestion. The following change to the language would be more accurate:<br>"How the methodology identifies transmisison Facilities that are expected by the AFC calculator to experience congestion on the transmission system."<br>R3. A Flowgate should not be defined as a thermal, voltage, or stability type due to the fact that Flowgates are limited by thermal, voltage, or stability problems that can vary depending on system conditions.<br>R4. through R8. should be combined into two requirements:<br>1) Each entity generating Flowgate limit values (note that it's not clear if this should be the Transmission |

| Question #10 | |
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| **Commenter** | **Comment** |
| | Owner, Transmission Planner, Planning Coordinator, and/or Reliability Coordinator) shall provide current Flowgate limit data to Transmission Service Providers (TSPs); and<br>2) TSPs shall use the lesser of the thermal, voltage, or stability limits that apply to the current system conditions.<br>R18.-sub-bullet 5, R23., and R24. should each have the "ATC"s replaced with "AFC"s, for the reasons explained in our response to the MOD-030-1 Comment Form's question 4.<br>R24. should have "path" replaced with "Flowgate", for the reasons explained in our response to the MOD-030-1 Comment Form's question 4. |
| **Response:** The SDT has included definitions of the methodologies for the glossary.<br>Regarding 4.1 through 4.5, we have modified the standard to use the phrase, 'for Posted Paths' and included a definition of 'Posted Path'.<br>R1.2 has been redrafted, and it is now included in R2.1 (See R2.1.3 in the revised standard.)<br>R3: We have changed the language in R3 to address this comment, and moved the language to 2.3.<br>Regarding R3 through R5, we have replaced this language with R2.3 and 2.5.<br>Regarding R24 Was deleted and is being addressed by NAESB along with the other requirements aimed at 'posting'. | |
| Duke | R1.1 does not create the same level of transmission service as created in MOD-028. MOD 028 R6.1 involves N-1 transmission contingency AND ramping/partial contingency of generation. MOD-030 R1.1 appears to only require N-1 transmission or generation contingency. This is not comparable service.<br>For R3. need to also include why the Flowgate is a limit |
| **Response:** MOD-028 as currently written allows for load adjustments instead of generation adjustments. Regarding R3, this will be addressed by NAESB, as will all other public posting requirements. | |
| ITC | We think this is a much better standard than MOD-028 and -029. It should provide for greater flexibility and reliability. We think all methods should be examined closely if there is any evidence of overselling (as evidenced byTLRs and market congestion) or underselling (as evidenced by denial of service without TLRs or market congestion). |
| **Response:** Thank you for your support. | |
| MEC Trading | This MOD should be combined with MOD-28 and everyone using a distribution factor based analysis should use the same methodology and the amount of consistency should be increased significantly. |
| **Response:** Most stakeholders supported the division of the various ATC calculation methods into separate standards. The SDT believes the differences between the two approaches merit two different standards | |
| MEC | 1. R1.1 implies that the only planning criteria that should be used in ATC calculations is Category B in Table 1 of the NERC Standards. That is incorrect, the methodology should describe how it meets the planning criteria that is appropriate for posted values including applicable NERC Standards, regional criteria, Transmission Owner criteria, etc. Therefore, R1.1 should state that "How methodology meets the planning criteria in NERC Standards, regional standards, Transmission Owner's planning criteria, Transmission Planner's planning criteria, and other applicable |

| Question #10 | |
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| **Commenter** | **Comment** |
| | planning criteria used by the Transmission Planner to plan the system.<br>2. R8 does not cover all the limitations that are possible for flowgates, for example, the limitation may be due to high transfers causing low voltage on the system after the next condition. This is not an example of a thermal rating or a voltage limit of the power transfer. I suggest that an additional bullet be added to R8 stating "Any other constraint to power transferred across the Flowgate, if applicable. For such constraints, the constraint should be defined, explained, and examples given in the methodology so as to ensure that the ATC methodology is transparent." As an alternative, a bullet should be added for "Steady-state voltage constraint."<br>3. The scheduling time horizon should be clarified.<br>4. The Standards Drafting Team indicated that they have decided not to define the term Existing Transmission Commitments, yet R13 uses that defined term with capital letters. The words Existing Transmission Commitments in R13 and elsewhere in the standard should not be capitalized so as not to indicate a defined term.<br>5. R22 change "covert" to "convert". |
| **Response:** 1.) R1.1 - We have changed the requirement to address this concern – the revised standard requires that contingencies used match those used in operations studies and planning studies for the applicable time periods.<br>2.) R8 – We believe the new language in R2.1.1 (R2.1.1. Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits) addresses this concern.<br>3.) We have asked NAESB to address scheduling timelines and how they relate to the release of unscheduled reservations.<br>4.) We have defined ETC within the standards themselves.<br>5.) We have corrected this typographical error. | |
| MRO | 1. R1.1 implies that the only planning criteria that should be used in ATC calculations is Category B in Table 1 of the NERC Standards. That is incorrect, the methodology should describe how it meets the planning criteria that is appropriate for posted values including applicable NERC Standards, regional criteria, Transmission Owner criteria, etc. Therefore, R1.1 should state that "How methodology meets the planning criteria in NERC Standards, regional standards, Transmission Owner's planning criteria, Transmission Planner's planning criteria, and other applicable planning criteria used by the Transmission Planner to plan the system.<br>2. R8 does not cover all the limitations that are possible for flowgates, for example, the limitation may be due to high transfers causing low voltage on the system after the next condition. This is not an example of a thermal rating or a voltage limit of the power transfer. The MRO suggests that an additional bullet be added to R8 stating "Any other constraint to power transferred across the Flowgate, if applicable. For such constraints, the constraint should be defined, explained, and examples given in the methodology so as to ensure that the ATC methodology is transparent." As an alternative, the MRO recommends that a bullet be added for "Steady-state voltage constraint."<br>3. MRO believes the scheduling time horizon should be clarified.<br>4. The Standards Drafting Team indicated that they have decided not to define the term Existing Transmission Commitments, yet R13 uses that defined term with capital letters. The words Existing Transmission Commitments in R13 and elsewhere in the standard should not be capitalized so as not to indicate a defined term.<br>5. R22 change "covert" to "convert". |

| Question #10 | |
|---|---|
| **Commenter** | **Comment** |
| **Response:** 1.) R1.1 - We have changed the requirement to address this concern – the revised standard requires that contingencies used match those used in operations studies and planning studies for the applicable time periods.<br>2.) R8 – We believe the new language in R2.1.1 (R2.1.1. Any Facility within the Transmission Operator's area based on thermal, stability or voltage limits) addresses this concern.<br>3.) We have asked NAESB to address scheduling timelines and how they relate to the release of unscheduled reservations.<br>4.) We have defined ETC within the standards themselves.<br>5.) We have corrected this typographical error. | |
| SERC ATCWG | The updating of flowgates as specified in Requirement 2 should be annually rather than quarterly. |
| **Response:** Since no other stakeholders disagreed with the 'quarterly' update and since no justification has been provided to support the change, the drafting team left 'quarterly' in the requirement. | |
| SRP | The standard should describe how flowgates and reliability limits should be determined such as is done for the Network Response Methodology MOD028 in requirement R6 and is done for the Rated System Path Methodology MOD029 in requirement R6.<br>Requirements R1.1, R1.2 & R1.3 are fill-in-the-blank requirements and need to specify rather than ask the tsp to explain what they do.<br>R8 - The standard should specify how the thermal, voltage and stability limited are determined. For example, are these n-0 or n-1 limits and are they transient or post-transient? |
| **Response:** 1.) The SDT has modified the standard to address this comment. R2.1 in the revised standard is the process for identifying Flowgates.<br>2.) The SDT has modified the standard to address this comment. R1.1 was moved into R2.1.2 and states, more specifically, how to treat contingencies in the identification of Flowgates. R1.2 and R1.3 were moved into R2.1.3 and identifies, more specifically, how to treat congestion in the identification of Flowgates<br>3.) The SDT has specified in R2.3 that the TFCs must respect SOLs. In the revised standard, the Transmission Operator is assigned responsibility for determining transfer capabilities and, the Transmission Operator will already have the thermal voltage and stability limits through requirements in other standards. | |