NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments — 2nd Draft of Standard MOD-029-1 — Rated System Path ATC (Project 2006-07)

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the first draft of standard MOD-029-1, Rated System Path 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 15 sets of comments, including comments from 72 different people from more than 40 companies representing 8 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:

- Title shortened to 'Rated System Path Methodology'
- Purpose statement revised to clarify that the purpose is to increase consistency and transparency in the development of transfer capability calculations rather than to promote consistent and uniform application and documentation of ATC calculations
- Applicability modified so that the requirement are assigned to the Transmission Operator and Transmission Service Provider – the Planning Coordinator and Reliability Coordinator are not assigned any requirements in the revised standard
- Eliminated R2, R9, and R16, requirements associated with making information 'publicly available' – NAESB business practices will address all posting requirements
- Rearranged the order of the requirements so that the sequence follows a more logical order. R1 (requires the documentation associated with the determination of TTC be organized in a report) was moved into R2 as the last step in the process of determining TTC.
- Put all the modeling requirements (R2 and R4) into a single requirement – R1.
- Deleted R5, the requirement to use assumptions consistent with those used in expansion planning, because the revised MOD-001 — Available Transfer Capability includes a requirement that addresses the same topic but is more comprehensive.
- R6 is the requirement that includes the steps in the process of determining TTC and this requirement was modified based on stakeholder comments to include consideration of Posted Paths limited by contract and to require the development of a nomogram under specific conditions. The step in the process that addressed situations where the TTC for a path is reliability-limited in one direction and flow-limited in the other direction.
- R7 and was a requirement for the Planning Coordinator to ensure TTCs were calculated and this has been deleted. In the revised standard the requirement to calculate TTCs is assigned to the Transmission Operator and is addressed in R2.

- R8 was a requirement for the Planning Coordinator to distribute its TTCs and the supporting information and this requirement has been deleted. In the revised standard the Transmission Operator is required to distribute the TTCs it has developed and this is addressed in R3.
- R10 was a requirement to calculate ATC at specified intervals and this requirement has been deleted. The revised MOD-001 — Available Transfer Capability includes the requirement to calculate ATC at specified intervals.
- R11 described how to calculate firm ATC and in the revised standard the descriptive language has been converted into an algorithm with each of the elements in the algorithm clearly defined. See R7 in the revised standard.
- R12 was a requirement to determine the impact of firm ETCs and this has been converted into an algorithm with each of the elements in the algorithm clearly defined. See R 5 in the revised standard.
- R13 and R14 were requirements to determine the impact of non-firm ETCs and these have been converted into an algorithm with each of the elements in the algorithm clearly defined. See R 6 in the revised standard. (Note that the posted version of the standard had a typographical error that separated R13 into two requirements and this had not been intended.)
- R15 was a requirement related to non-firm ATC and this deleted as a separate requirement – the revised standard includes a specific algorithm for the determination of non-firm ATC that includes the intent of R15 in the definition of 'postbacks.'
- Added measures and compliance elements.

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.	Ken Goldsmith - (G3)	ALT	✓				✓					
4.	E. Nick Henery – (G1)	APPA	✓									
5.	Jerry Smith (G6)	APS-TP										
6.	Stephen Tran	BC Transmission Corp.		✓								
7.	Dave Rudolph - (G3)	BEPC	✓		✓		✓	✓				
8.	Steve Tran (G6)	BP TX										
9.	Abbey Nulph (G6) (I)	BPA	✓		✓		✓	✓				
10.	Rebecca Berdahl (G6)	BPA	✓		✓		✓	✓				
11.	Steve Knudsen (G6)	BPA	✓		✓		✓	✓				
12.	Charles Mee (G6)	CA Dept Water & Power										
13.	Brent Kingsford – (G2)	CAISO		✓								
14.	Greg Ford (G6)	CISO-TP		✓								
15.	Ed Davis	Entergy Services Inc.	✓		✓		✓	✓				
16.	George Bartlett	Entergy Services Inc.	✓		✓		✓	✓				
17.	Jim Case	Entergy Services Inc.	✓		✓		✓	✓				
18.	Narinder K. Saini	Entergy Services Inc.	✓		✓		✓	✓				
19.	Steve Myers – (I) (G2)	ERCOT		✓								✓
20.	Patricia vanMidde (G6)	FERC Case MRG, Sempra										
21.	Dave Folk	FirstEnergy Corp.	✓		✓		✓	✓				
22.	Phil Bowers	FirstEnergy Corp.	✓		✓		✓	✓				
23.	Richard Kovacs	FirstEnergy Corp.	✓		✓		✓	✓				
24.	Joe Knight - (G3)	Great River Energy	✓		✓		✓					
25.	Danielle Beaulieu	Hydro-Québec TransÉnergie (HQT)	✓									
26.	Roger Champagne – (I) (G4)	Hydro-Québec TransÉnergie (HQT)	✓									
27.	Ron Falsetti – (I) (G2)	IESO		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
28.	Lou Ann Westerfield (G6)	IPUC-SP										
29.	Charles Yeung – (G2)	IRC		✓								
30.	Matt Goldberg – (G2)	ISO New England (ISO NE)		✓								
31.	Kathleen Goodman– (G4)	ISO New England (ISO NE)		✓								
32.	Sueyen McMahon (G6)	LADWP	✓		✓		✓	✓				
33.	Eric Ruskamp - (G3)	LES	✓		✓		✓	✓				
34.	Robert Coish - (G3)	Manitoba Hydro Electric Board (MHEB)	✓		✓		✓	✓				
35.	Tom Mielnik – (I) (G3)	MidAmerican Energy Company (MEC)	✓		✓		✓	✓				
36.	Carol Gerou - (G3)	Minnesota Power (MP)	✓		✓		✓	✓				
37.	Bill Phillips – (G2)	MISO		✓								
38.	Terry Bilke - (G3)	MISO		✓								
39.	Mike Brytowski - (G3)	MRO										✓
40.	Grag Campoli	New York ISO (NYISO)		✓								
41.	Jim Castle – (G2)	New York ISO (NYISO)		✓								
42.	Ralph Rufrano	New York Power Authority (NYPA)	✓		✓							
43.	Al Adamson – (G4)	New York State Reliability Council										✓
44.	Matt Schull – (G1)	North Carolina MPA (NCMPA)			✓	✓	✓	✓				
45.	Guy V. Zito – (G4)	NPCC										✓
46.	Todd Gosnell - (G3)	OPPD	✓		✓			✓				
47.	Brian Weber (G6)	Pacificorp	✓				✓					
48.	Alicia Daugherty – (G2)	PJM		✓								
49.	G. O'Neal Hamilton-(G5)	PSC of South Carolina									✓	
50.	John E. Howard – (G5)	PSC of South Carolina									✓	
51.	Mignon L. Clybur – (G5)	PSC of South Carolina									✓	
52.	Phil Riley – (G5)	PSC of South Carolina									✓	
53.	Randy Mitchell – (G5)	PSC of South Carolina									✓	
54.	C. Robert Moseley– (G5)	PSC of South Carolina									✓	
55.	David A. Wright – (G5)	PSC of South Carolina (PSC SC)									✓	
56.	Chuck Falls (I) (G6)	Salt River Project (SRP)	✓		✓		✓	✓				
57.	Bob Schwermann (G6)	SMUD	✓		✓		✓	✓				
58.	Brian Jobson (G6)	SMUD	✓		✓		✓	✓				
59.	Dick Buckingham (G6)	SMUD	✓		✓		✓	✓				
60.	Dilip Mahendra (G6)	SMUD	✓		✓		✓	✓				
61.	W. Shannon Black (G6)	SMUD	✓		✓		✓	✓				
62.	Phil Odonnell (G6)	SMUD- Ops	✓		✓		✓	✓				
63.	Casey Sprouse (G6)	Sr. Term Marketer										

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
64.	Maria Denton (G6)	SRP										
65.	Terri M. Kuehneman (G6)	SRP System Operation										
66.	Raquel Agular (G6)	Tucson	✓		✓		✓	✓				
67.	Ron Belval (G6)	Tucson	✓		✓		✓	✓				
68.	Jim Haigh - (G3)	WAPA	✓					✓				
69.	Raymond Vojdani (G6)	WAPA									✓	
70.	Mike Wells (G6)	WECC										✓
71.	Neal Balu - (G3)	WPS			✓		✓	✓				
72.	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
G4 – NPCC CP9 Reliability Standards Working Group
G5 – PSC of South Carolina
G6 - WECC MIC MIS ATC Task Force

Index to Questions, Comments, and Responses

1. FERC has ordered that the TTC for all posted paths be calculated by using one of three methodologies (1 Rated System Path, 2 Network Response & 3 Flow base). The Rated System Path (RSP) Standard (MOD-029-1) is modeled after the WECC Path Rating Methodology which does not require that all posted paths be rated using the WECC Methodology. There are many posted paths within WECC whose ratings were not calculated using the WECC Path Rating process and would need to be re-rated to conform to the RSP Standard. Should the RSP Standard address this issue? If "Yes" please explain how you believe it should be addressed in the comments area.

Summary Consideration: The SDT has opted to adopt the FERC / NAESB approach to "Posted Path" to define the universe of paths addressed in this standard. Further, the SDT has adopted comments suggesting a high level methodology for calculating TTC accompanied by additional delimiters to address a large universe of unique and peripheral circumstances that accompany this approach. Finally, the SDT will adopt a phased in approach when formulating the implementation schedule for this standard to account for the potentially large number of Posted Paths which must be studied or re-studied in order to conform to the new requirements imposed by this standard.

Question #1			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	This is the very reason why it is necessary for the TSP to go the TP, PC, RC or TOP (depending on the time horizon of the ATC calculation) which has determined the TTC for reliable operational and planning reasons. Whatever, method the reliability functions have used will be communicated to the TSP and they will post the values and backup information for the calculations.
Response: This is what is intended.			
IRC		☑	We do not believe the RSP Standard needs to specifically address WECC Path ratings which were not rated using the WECC Path Rating process.
Response: The SDT has opted to adopt the existing FERC / NAESB approach of "Posted Path" to define the universe of paths affected by this standard.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC / Charles Yeung.			
PSCSC		☑	
FirstEnergy		☑	
WECC MIC MIS ATC TF.	☑		The TTC determinative process for the Rated System Path methodology accurately resides in the MOD-29. The WECC Team suggests that these determinants be fully vetted through the augmented expertise of those being added to the team via the most recent ATC SAR. The WECC Team does not believe it is FERC's intent to require a posting of TTC for each and every path and each and every possible permutation of paths or POR/PODs within a utility's system. It is estimated that this could result in a million plus postings for some utilities; most of these posting would be on paths for which no service has been requested. Rather, FERC has already made it clear that as to posting of ATC and TTC, FERC's intent was stated

Question #1			
Commenter	**Yes**	**No**	**Comment**
			in its approved definition of "Posted Path." It is the "Posted Path" that requires a posting of ATC and TTC. The WECC Team has the below positive suggestions that will remedy many concerns for MOD-29. Suggested Remedy: 18 CFR 37.6, Order 889/RM95-9-000, P. 58-60 and NAESB R-4005 all utilize "Posted Path" as the delineated paths for which ATC and TTC must be posted. At 18 CFR 37.6, the definition for Posted Path states: (control area has been replaced with Balancing Authority to bring the definition in line with the Functional Model) Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. See also: 18 CFR 37.6; http://a257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/aprqtr/pdf/18cfr37.5.pdf First, in refining this draft the term "Posted Path" must be adopted in accordance with FERC's intent. The WECC MIC MIS ATC TF Team suggests the following rewrite of R6: R6. For each Posted Path, each Planning Coordinator shall determine TTC using the applicable method below: R6.1. For Posted Paths whose capacity is limited by thermal, voltage or stability limits, TTC shall be the lesser of the thermal, voltage or stability limits as determined by adjusting generation dispatch, area interchange schedules, and Load levels to maximum values (without introducing fictitious facilities or unrealistic values into the system model) to determine the maximum flow that can be simulated on the path while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria. • If it is not possible to simulate a flow sufficiently large to reach a reliability-limited TTC, the TTC of the path is equal to the maximum flow simulated and the path is said to be flow limited. • If the TTC determined for a path in one direction is reliability limited and the TTC determined for the same path in the other direction is flow limited, the reliability limited TTC may be used for both directions. R6.2. for Posted Paths whose capacity is limited by contract, TTC shall be set on the Posted Path at the maximum allowable contract capacity, not to exceed the thermal, voltage or stability limits of that Posted Path. R6.3 For Posted Paths whose capacity is jointly owned, TTC shall be set for each separate owner of the Posted Path at the maximum capacity owned by each separate owner. R6.3.1. The Transmission Service Provider shall ensure that for jointly owned paths, the sum of all owners' allocations is equal to the TTC of the path

Question #1			
Commenter	**Yes**	**No**	**Comment**
			R6.4. For Posted Paths whose capacity has been established for ten years or more (subject to contingency and seasonal adjustment), and that are known to have operated reliably at that established capacity rating, TTC shall be set on the Posted Path at the established, reliable level at which that Posted Path has been operating for at least the previous ten years. R6.5. For new or revised Posted Paths, the Planning Coordinator shall determine if the TTC adversely impacts the path rating or TTC values of existing paths by modeling the flow on the new or revised Posted Path at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level, and if there is an adverse impact: • Limit the TTC for the new or revised path to eliminate the adverse impacts, or • Follow a local or regional procedure for resolving the impact with the affected parties. R6.6. Draft a report to document the steps performed in determining the TTC for the Posted Path.
Response: The SDT has accepted those comments with the exception that "R6" as included in the last drafted release should be changed from "maximum values" to "maximum or minimum values." The SDT modified the standard adopting the intent of most of the suggestions identified above. The drafting team adopted the term, 'Posted Path' with the proposed definition. The term, 'Posted Path' is now used consistently in the set of ATC-related standards. R6 was modified to include the term, 'Posted Path' and the requirement was further modified, based on other stakeholder comments, to assign responsibility for determining TTC to the Transmission Operator rather than the Transmission Service Provider.			
SRP	☑		SRP supports the comments on this subject submitted by the WECC contingent. Additionally we suggest that the drafting team provide for a "phasing-in" period to allow time for the TSP's who use the Rated System Path Methodology to re-study the TTC for their Posted Paths. This is needed because of the large number of Posted Paths in the west whose TTC was not established by the rigorous methodology stipulated in the R6 of the new standard. If a "phasing-in" period is not appropriately addressed in the standard itself it needs to be provided for somewhere. We suggest an Implementation Plan similar to the CIP Standards. One that requires the Responsible Entities to become Substantially Compliant, Compliant, and then Audibly Compliant within a defined schedule.
Response: The SDT concurs that MOD-29 as drafted may expose some entities to compliance risk. The SDT also concurs that a phased in approach is appropriate and necessary and will take that into consideration when the implementation schedule is formulated for this standard.			
Entergy	☑		Each Transmission Service Provider should calculated TTC for all posted using the same method for consistency
Response: The SDT agrees and believes adoption of the WECC comments will greatly enhance consistency in calculating TTC under this selected methodology.			

2. Do you believe that all elements of ETC relevant to the RSP Methodology have been adequately captured in Requirements twelve and fourteen (R12 and R14)? If "No" please explain how you believe it should be addressed in the comments area.

Summary Consideration: Most stakeholders who responded to this comment indicated that the requirements relative to ETC needed improvement. The drafting team modified the requirements by converting the descriptive language into algorithms with a definition for each element in each algorithm:

In the revised standard, the algorithm for firm ETC is: $ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$

Where:

NL_F is the firm capacity reserved to serve peak Native Load forecast commitments for the time period being calculated, to include Native Load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the capacity reserved for grandfathered Firm Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service,

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service.

In the revised standard, the algorithm for non-firm ETC is: $ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$

Where:

$NITS_{NF}$ is the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity reserved for grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm.

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 R12.2.
Response: The SDT has included the impact of load growth in Network Integration Transmission Service. The revised standard includes an algorithm for firm ETC, and in that algorithm, **$NITS_F$** is defined as the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin. The revised standard also includes an algorithm for non-firm ETC, and in that algorithm, **$NITS_{NF}$** is defined as the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.			
APPA		☑	See my comments on MOD-028
Response: The SDT has reviewed the appropriateness of the functions and endeavored to accurately align them with the NERC Functional Model. In all of the revised standards, the responsibility for determining TTC or TFC is assigned to the Transmission Operator, and the responsibility for determining ATC is assigned to the Transmission Service Operator.			
BPA		☑	The impact of load growth for Network Integration Transmission Service should be included in R12.2. The "five years or longer in duration" language should be removed from R12.5. 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.
Response: The SDT modified the standard in support of these suggestions. The revised standard includes an algorithm for firm ETC, and in that algorithm, **$NITS_F$** is defined as the firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin. The revised standard also includes an algorithm for non-firm ETC, and in that algorithm, **$NITS_{NF}$** is defined as the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin. The reference to 'five years or longer' was removed as suggested.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Entergy		☑	We suggest that R12.10 should be a stand alone requirement rather than a sub requirement. R 13 should be a lead requirement with R14 and R 14.1 - R14.5 as sub requirements under R13 requirements. R15 is similar to post back, therefore, it should also be made as a subrequirement under R13.
Response: R12.10 was revised and instead of a description of how to calculate non-firm ATC, in the revised standard, there is an algorithm that identifies how to calculate non-firm ATC. R14 should have been a sub-requirement under R13 – this was a typographical error in the version that was posted for comment. In the revised standard there is an algorithm for the calculation of non-firm ETC that includes what had been R13 through R14.5. R15 has been absorbed into the algorithm for determining non-firm ATC in Postbacks. (See R8 in the revised standard.)			
IESO		☑	We feel that R12.1, R12.2, R12.6 and R14 leave room for double counting for components that shold have been taken care of by TRM and CBM. Further, details to be included for non-firm ATC calculation are missing in R13.
Response: In the revised standard, the numbering and structure of the standard has been reorganized for clarity. The SDT cannot comment on IESO's concern at R13 addressing missing non-firm components as IESO has given the SDT no guidance as to what they believe is missing. R12.1, 12.2, 12.6 and R14. all include the as the qualifier "not otherwise included in TRM and CBM" to prevent double counting between either of those standards (MOD-04 and MOD-08) and MOD-29.			
IRC		☑	We feel that R12.1, R12.2, R12.6 and R14 leave room for double counting for components that shold have been taken care of by TRM and CBM. Further, details to be included non-firm ATC calculation are missing in R13.
Response: R12.1, 12.2, 12.6 and R14. all include the qualifier "not otherwise included in TRM and CBM" to prevent double counting between either of those standards (MOD-04 and MOD-08) and MOD-29.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC / Charles Yeung.			
HQTE NPCC	☑		R12.10 should be renumbered R13, R13 should be renumbered R14, R14 should be renumbered R14.1, R14.1 should be renumbered R14.2 (etc.)
Response: The SDT agrees that the standard as drafted would be clearer if restructured and has reorganized the standard for clarity in the revised standard.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
R12.10 was revised and instead of a description of how to calculate non-firm ATC, in the revised standard, there is an algorithm that identifies how to calculate non-firm ATC. R14 should have been a sub-requirement under R13 – this was a typographical error in the version that was posted for comment. In the revised standard there is an algorithm for the calculation of non-firm ETC that includes what had been R13 through R14.5.			
PSCSC	☑		

3. Would the reliability of the system be diminished if the flow limited TTC requirement in this standard (R6.1) was relaxed such that fictitious devices (e.g. fictitious generators or load or phase shifting transformers) could be modeled in the simulation in order to raise the flow on a flow limited path to a reliability limit and then allow the reliability limited rating to take precedence over the flow limited rating? Please explain your answer in the comments area.

Summary Consideration: Most stakeholders who responded to this question indicated that reliability would not be diminished if the standard allowed the modeling of fictitious devices. The drafting team removed the parenthetical phrase that had been included in R6.1 which precluded the use of fictitious facilities, but did not make any other revisions to MOD-029 to specifically address the use of fictitious devices**.** The revised standard is silent on this matter – and does not require nor prohibit the use of fictitious modeling elements.

R~~6~~2.1 Except where otherwise specified within MOD-029-1, adjust ~~Determine the reliability limited TTC for a path by adjusting~~ base case generation schedules and Load levels ~~to extreme values (without introducing fictitious facilities into the model)~~ within the updated power flow model to determine the maximum flow (reliability limit) that can be simulated on the Posted P~~p~~ath while at the same time satisfying ~~the~~ all planning for N-0, N-1, and N-2 contingencies as follows: ~~criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria~~.

Question #3			
Commenter	**Yes**	**No**	**Comment**
PSCSC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Response: The SDT concurs and appreciates your participation.			
APPA			R6 and its Sub-requirements are study methodologies that should not be included in any standard. Requirements of this nature could be interpreted to mean that an entities' future plan that included a resource 6 years from now would be fictitious if in the next planning cycle they determined to remove it. These Standards are written in a Policy format.
Response: R6 and its sub-requirements outlined the required actions to determine TTC using the rated system path methodology and are necessary to ensure consistency in the determination of TTC. The revised standard does not require nor prohibit the usage of fictitious modeling elements. However, FERC has stated that: "We conclude that the NERC process is appropriate as it is open to all industry participants and, therefore, is a suitable arena for establishment of common standards for modeling assumptions." Order 890. P. 298. The standards have been rewritten such that they no longer reflect a Policy format as suggested by this commenter.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
BCTC		☑	The use of artificial input data to increase a TTC limit for scenarios analysis and evaluating the impacts of a proposed generator (which is a fictitious until it has been constructed) would not diminish the liabilty of the system.
Response: The SDT concurs that in most cases usage of fictitious elements in modeling will not diminish the reliability of the grid for those using the RSP. Further, the revised standard does not require nor prohibit the usage of fictitious modeling elements.			
Entergy		☑	Realistically TTC should be calculated using any controls that can impact flow on the path. By not using all controls such as phase shifting transformers, TTC values are lower than what they can practically be, therefore, potential of underutilizing the transmission system.
Response: The revised standard does not require nor prohibit the usage of fictitious modeling elements. Note that the revised standard includes more specific requirements concerning modeling, including requiring the modeling of phase shifting transformers.			
IRC		☑	Reliability would not be diminished by fictitions simulations. This practice is not uncommon in the determination of operating limits and TTCs when available resources are insufficient to stress an interface or transfer level to the "edge".
Response: The SDT is in agreement with the commenter. The revised standard does not require nor prohibit the usage of fictitious modeling elements.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: Please see the response to IRC's comments.			
FirstEnergy		☑	Permitting the arbitrary introduction of fictitious devices potentially encourages producing the limitation wanted rather than determining the actual limitation. First bullet in R6.1 says the path will be said to be "flow limited", which is a misleading characterization. It really would be "extreme value limited" and should be identified as such. The second bullet in R6.1 seems to be very arbitrary and should be deleted to result in a limit that more accurately reflects the actual ability of the system to transfer power.
Response: Utilization of fictitious elements in modeling has routinely and reasonably been used by those utilizing the Rated System Path for some time. However, in moving into a mandatory regime the inclusion of this discretionary approach as a mandate may not produce an optimum outcome. Thus, the SDT has opted not to make inclusion or exclusion of fictitious modeling elements a Requirement. As to inclusion of the term "flow limited" the term is used widely in the industry, with particular emphasis on those currently using the RSP, that inclusion was warranted Nevertheless, the term flow limited has been deleted from the next version of			

Question #3			
Commenter	**Yes**	**No**	**Comment**
the standard.			
IESO		☑	Reliability would not be diminished by incorporating fictitious devices into power flow simulations. This practice is not uncommon in the determination of operating limits and TTCs when available resources are insufficient to stress an interface or transfer level to the "edge" or for other practical modeling reasons. However, entities which use such fictitious devices must ensure that its modeling assumptions are shared with other possible affected entities.
Response: The SDT is in agreement with the commenter. The revised standard does not require nor prohibit the usage of fictitious modeling elements. The standard does require sharing of assumptions.			
SRP		☑	The system should be reliable if the TTC in both directions of all paths is reliability limited even if one or more of the reliability limits was found using fictitious devices for stressing the system in order to determine the reliability limit. The flow limit does not represent the capability of the transmission system to reliably transfer power. It does represent the limit of the capability of the system to stress the system which doesn't imply the limit beyond which reliability is in jeopardy.
Response: The revised standard does not require nor prohibit the usage of fictitious modeling elements.			
HQTE NPCC	☑	☑	Real-time system reliability would not be diminished since the actual power transfer is less than the reliability limit. However, long-term reliability could be diminished because posted TTC would be higher than the actual maximum flow. Transmission users could overestimate the path capacity and consequently overestimate the amount of power that can be delivered on this specific path. A path might be voltage limited, not flow limited, and the introduction of a fictitious generator might hide the reliability rating if it supports the voltage on the path in the simulation, but not in "real life".
Response: The commenters' point is well taken and properly noted. Nevertheless, in moving into a mandatory regime the inclusion of this discretionary approach as a mandate may not produce an optimum outcome. Thus, the SDT has opted not to make inclusion or exclusion of fictitious modeling elements a Requirement.			
BPA	☑		Allowing the use of artificial input data to increase a TTC limit does not represent the most relevent system conditions to establish a reliabilty limit.
Response: The revised standard does not require the usage of fictitious modeling elements.			

4. Does this standard need to address the practice of selling the same Non-Firm Transmission multiple times? Please explain your answer in the comments area.

Summary Consideration: The stakeholders who responded to this question all indicated that the standard does not need to address the practice of selling the same Non-firm Transmission multiple times. Based on this consensus, the SDT has concluded that the selling of non-firm multiple times should be a NAESB Business Practice and has referred the issue to NAESB. By contrast, "how" non-firm is calculated and accounted for after that calculation is made remains a NERC issue and is included herein.

Question #4			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC TF		☑	The incremental sells of the same non-firm transmission to multiple customers represents a prioritization issue that would best be addressed in a NAESB Business Practice.
Response: The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to NAESB.			
APPA		☑	This is a business practice, not reliability
Response: The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to NAESB.			
Entergy		☑	Sale of service should not be in scope of this standard, only how TTCs and ATCs are calculated should be included. Accounting for Non-Firm Transmission already sold multiple times should be included in this standard so that accurate ATCs can be calculated and offered for sale to the market place. Sale of Non-Firm Transmission multiple times is a commercial issue and should be addressed by NAESB Business Practice Standard.
Response: The SDT concurs.			
FirstEnergy		☑	This is better covered by NAESB as a business practice issue. However, the requirements for loading and unloading the interchange schedules associated with this practice should be included in the NERC Standards to ensure that reliability is not jeopardized.
Response: The SDT has recommended that "practices" be referred to NAESB. However, the SDT is unclear as to the nuances within the "requirements for loading and unloading the interchange schedules" that FirstEnergy would have the SDT address. FirstEnergy is encouraged to clarify their concerns and make recommendations.			
HQTE NPCC		☑	As requested in R12.10, non-firm ATC is calculated by reducing TTC by non-firm-ETCs. Depending on time horizon, unscheduled transmission service could be sold multiple-times This is a business issue that should be addressed by NAESB.
Response: The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to			

Question #4			
Commenter	**Yes**	**No**	**Comment**
NAESB.			
IESO IRC		☑	This seems to be a business practice issue. Similar issues are selling non-firm services out of TRMs and/or CBMs which may be recalled when these latter components need to be used for capacity needs or transmission reliability needs.
Response: The selling of non-firm multiple times should be a NAESB Business Practice and we will refer that issue to NAESB.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See the response to IRC's comments.			
PSCSC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Response: The SDT concurs and appreciates your participation.			

5. Does R13 or R14 need to be reworded to explicitly clarify that CBM must be offered for sale as Non-Firm transmission? Please explain your answer in the comment area.

Summary Consideration: The SDT has included new language to address how non-firm is treated within the ATC calculation. Here is the algorithm for calculating non-firm ATC as included in the revised standard:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counter\text{-}schedules_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the Posted Path for that period.

TTC is the Total Transfer Capability of the Posted Path for that period.

ETC_F is the sum of existing non-firm commitments for the Posted Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the Posted Path during that period.

CBM_S is the Capacity Benefit Margin for the Posted Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the Posted Path that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period,

$Postbacks_{NF}$ are adjustments to non-firm Available Transfer Capability due to postbacks for that period, as defined in business practices, and

$Counter\text{-}schedules_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document.

Question #5			
Commenter	**Yes**	**No**	**Comment**
PSCSC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Response: The SDT concurs and appreciates your participation.			
NPCC		☑	This is a business issue to be addressed by NAESB.
Response: The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments in Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890: Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards			

Question #5			
Commenter	**Yes**	**No**	**Comment**
development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.			
WECC MIC MIS ATC TF	☑		As drafted the standard is unclear. This team suggests language that better reflects the following: Order 890, P. 351. "The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS." For clarity, this statement needs to be reconciled with MOD-04-1, R.3.4 stating, "The Transmission Service Provider shall use "zero" as the value for all unscheduled CBM for all non-firm ATC calculations for all methodologies. Order 890. P. 262.
Response: The SDT clarifies that the "calculation" for CBM should be in MOD-04. However, this MOD-29 Requirement stipulates the "application" of the resulting CBM calculation as one variable within the overall ATC calculation as stipulated in MOD-29. Restated: The CBM variable is calculated in MOD-04; the value is then applied to the overall ATC equation described in MOD-29. To address the stated concern, the SDT has Modified the non-firm ATC calculation to include only scheduled CBM. See the algorithm in the Summary Consideration above.			
APPA		☑	This should be removed, the rules for using CBM should stay in the CBM standards.
Response: The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments in Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890: Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.			
FirstEnergy		☑	MOD-004 should contain all the rules related to CBM. However, R13 and R14 should be renumbered to reflect the appropriate formatting.
Response: The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments in Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890: Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that			

Question #5			
Commenter	**Yes**	**No**	**Comment**
LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage. R14 should have been a sub-requirement under R13 – this was a typographical error in the version that was posted for comment. In the revised standard there is an algorithm for the calculation of non-firm ETC that includes what had been R13 through R14.5.			
HQTE		☑	This is a business issue to be addressed by NAESB.
Response: The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890: Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.			
Entergy	☑		For consistency with other methods, excluding CBM from Non-Firm ETC should be included in this standard..
Response: .Agree.			
IESO IRC	☑		It needs to be, but then again it may be a business practice issue. Along this vein, MOD-028 is silent on this and also has no mention of the CBM quantity in the calculation of non-firm ATC.
Response: The SDT concurs that it has overtones of a business practice; however, in light of FERC's comments Order 890, P. 262, at this stage of drafting it should be included in the NERC process and not the NAESB process. Here is the directive from Order 890: Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.			

Question #5			
Commenter	**Yes**	**No**	**Comment**
Note that the revised MOD-028 does include an algorithm for the calculation of non-firm ATC and it does require consideration of CBM. Here is the algorithm for determining ATC using the Area Interchange Methodology: ATC_{NF} = TTC – ETC_F - ETC_{NF} – CBM_S – TRM_U + $Postbacks_{NF}$ + $Counterflows_{NF}$ CBMs is the Capacity benefit margin for the postd path that has been scheduled during that period			
ERCOT	☑		See IRC comments submitted by Charles Yeung.
Response: See response to IRC's comments.			

6. Should R14 and R15 be combined to clarify the calculation for non-firm ATC? Please explain your answer in the comments area.

Summary Consideration: After the posting of the Comment request, the NERC ATC Team met with FERC for a progress report on these standards. It was concluded that greater detail needed to be added to many of the affected standards. The NERC Team further decided that a more uniform structuring across the MOD-28-29-30 standards would better serve the industry. Although it is not anticipated that each of these three standards will be completely uniform in structure, any movement toward that goal will renumber / restructure and reorganize the flow of each affected standard accordingly.

The revised standard does include the following algorithm for the determination of non-firm ATC:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counter\text{-}schedules_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the Posted Path for that period.

TTC is the Total Transfer Capability of the Posted Path for that period.

ETC_F is the sum of existing non-firm commitments for the Posted Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the Posted Path during that period.

CBM_S is the Capacity Benefit Margin for the Posted Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the Posted Path that has not been released for sale as non-firm capacity by the Transmission Service Provider during that period,

$Postbacks_{NF}$ are adjustments to non-firm Available Transfer Capability due to postbacks for that period, as defined in business practices, and

$Counter\text{-}schedules_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and described in its Available Transfer Capability Implementation Document.

This shall serve as a single response to all comments offered in response to this question.

Question #6			
Commenter	**Yes**	**No**	**Comment**
PSCSC			Our comments are from a regulatory perspective. This is strictly a technical issue.
NPCC		☑	R14 is for planning and operating horizons and R15 is only for operating horizon
APPA		☑	These are confusing and should be removed. R14 is written in a manner it is impossible to determine which Reliability function is responsible to meet the standard. In addition, any reference to non-firm

Question #6			
Commenter	**Yes**	**No**	**Comment**
			ATC should be in MOD-001, not spread out through several standards.
HQTE		☑	R14 is for planning and operating horizons and R15 is only for operating horizon
WECC MIC MIS ATC TF	☑		Merely combining these may not be sufficient to make clear what the TSP is supposed to do. R14 should, at minimum, be a subset of R13, lest there be no responsible party. Adding R15 as a subset of R13 would be appropriate. Some in WECC assert that all "non-firm" is a business practice to be determined by NAESB. Others believe "non-firm" should be addressed in MOD-01 - not here.
Entergy	☑		Please see comments to Question 2 above
ERCOT	☑		See IRC comments submitted by Charles Yeung.
FirstEnergy	☑		They should be combined to strengthen the reader's understanding of the material.
IESO	☑		R14 and R15 could be combined. However, in R15, we do not understand what would be the items that are "the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC,.."
IRC	☑		R14 and R15 may be combined. However, in R15, we do not understand what would be the items that are "the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC,.."

7. 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: The SDT has engaged NERC and the Functional Model team in an effort to add additional Applicable entities for insertion into the standard(s). That dialogue is ongoing. The SDT has requested a new role of "Operations Planner" utilizing the Functional Model. In the interim, the term Transmission Operator has supplanted Operations Planner. The Reliability Coordinator and Planning Coordinator were removed as 'applicable entities' in the revised standard. In the set of revised standards, the Transmission Operator has been assigned responsibility for determining TTC and TFC and the Transmission Service Provider has been assigned responsibility for determining ATC.

Question #7			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC TF		☑	Although the "Applicability" section states it is applicatable to Relaibility Coordinators, there is nothing in the draft that applies to an RC.
Response: References to the Reliability Coordinator have been removed.			
APPA		☑	See Comments on MOD-029
Response: We do not find your additional comments on MOD-29.			
BCTC		☑	ATC related standards should be applicable only to entities who have the obligation to provide non-discrimintory transmission service, that is the Transmission Service Providers.
Response: The SDT believes this standard applies to entities other than the TSP. For example, the TSP is required to post assorted data. If there is no requirement for the providing entity to supply the data, the TSP cannot be obligated to post that which other entities will not provide. Thus, additional entities are implicated. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. The requirements for the Planning Coordinator and Reliability Coordinator were removed from the revised 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: According to members of the Functional Model Work Group, the Planning Coordinator and the Planning Authority are essentially the same. The drafting team will post a definition of 'Planning Coordinator' so that it can be formally entered into the NERC Glossary of Terms Used in Reliability Standards.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.

Question #7			
Commenter	**Yes**	**No**	**Comment**
Response: See response to IRC.			
IESO		☑	Unlike the other MOD standards, this standard more appropriately reflect the role of the PC and RC in the determination of transfer capabilities, not ATC. However, the applicability section gives rise to unclear responsibilities between TSP and the PC/RC in that both calculate transfer capabilities of the "paths". We feel that the PC and RC are responsible for calculating the total path capability, whereas the TSP is responsible for calculating the available path capability. This distinction needs to applied to all the MOD standards.
Response: The SDT concurs that the RC is not responsible for calculating TTC. Please see the Summary Consideration for this question. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. The requirements for the Planning Coordinator and Reliability Coordinator were removed from the revised standard.			
IRC		☑	Unlike the other MOD standards, this standard more appropriately reflect the role of the PC and RC the determination of transfer capabilities, not ATC. However, the applicability section gives rise to unclear responsibilities between TSP and the PC/RC in that both calculate transfer capabilities of the "paths". We feel that the PC and RC are responsible for calculating the total path capability, whereas the TSP is responsible for calculating the available path capability.
Response: See comments at the summary header of this section. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC. The requirements for the Planning Coordinator and Reliability Coordinator were removed from the revised standard.			
NPCC HQTE	☑	☑	MOD-029 includes applicability to Reliability Coordinator, but there is no reference in the details of the standard to the RC. A role should be defined, or RC should be removed from the Applicability section. All MOD standards should be consistent in their description of the roles for providing input and calculating ATC.
Response: References to the RC have been removed. In the revised set of standards (MOD-028, MOD-029, MO-030), the drafting team assigned the Transmission Operator the responsibility for determining TTC or TFC and assigned the Transmission Service Provider with the responsibility for determining ATC.			
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: The SDT discussed this issue in depth and asked stakeholders for feedback on this issue – most stakeholders			

Question #7			
Commenter	**Yes**	**No**	**Comment**
supported separating the standards – as this adds clarity by providing more details on each of the the diverse metholdogies addressed therein.			
Entergy	☑		
PSCSC	☑		

8. 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 RSP. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to the RSP methodology in this draft of MOD-029-1? If "No," please explain your answer in the comments area.

Summary Consideration: The SDT has adequately addressed the directives identified in the FERC Orders 890 and 693 related to Rated System Path**.** To assist stakeholders, when the revised standards are posted, the drafting team will post a table that shows each of the directives and identifies the standard in which the directive is addressed.

Question #8			
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: After clarification from FERC and in depth discussions on this issue, the SDT is proposing to retire FAC-12 and 13 and has imported all substantive requirements into the appropriate MOD-28-29-30.			
IESO IRC	☑	☑	It appears that the SDT has addressed all of the FERC directives. However, in view of the many comments provided to this and the other related MOD standards, and hence substantive changes are expected, we see the need to revisit this subject again when revised standards are posted.
Response: To assist stakeholders, when the revised standards are posted, the drafting team will post a table that shows each of the directives and identifies the standard in which the directive is addressed.			
ERCOT	☑	☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC.			
FirstEnergy		☑	
Entergy	☑		

Question #8			
Commenter	**Yes**	**No**	**Comment**
FirstEnergy	☑		
PSCSC	☑		

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 identify the conflict in the comments area.

Summary Consideration: In general the industry has identified no regulatory conflicts. However, the industry does remain concerned that some if not all of these standards may not apply to them based on their specific circumstance. Assigning liability is outside the scope of this SDT. Where an entity believes they are exempt for regional differences the regional variance process is available.

Question #9			
Commenter	**Yes**	**No**	**Comment**
APPA			See question 8 above
Response: See response above to APPA on Question 8.			
HQTE			We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets.
Response: The SDT concurs and suggests that the narratives required in the ATCID and the OATT Attachment C should address HQTE's concerns; however, HQTE has raised enforcement concerns that are outside the scope of the SDT.			
IESO IRC		☑	No, but please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities.
Response: The SDT concurs.			
NPCC			We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets.
Response: The SDT concurs.			
PSCSC		☑	
WECC MIC MIS ATC TF		☑	
BCTC		☑	
Entergy		☑	
ERCOT	☑		ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through

Question #9			
Commenter	**Yes**	**No**	**Comment**
			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. 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. 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. 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. 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. In the current and future ERCOT market design the method of calculating ATC, TTC and the use of

Question #9			
Commenter	**Yes**	**No**	**Comment**
			CBM and TRM are not applicable to the ERCOT Interconnection. 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 Balancing Authority 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 drafting team believes the Applicable Entities delineated in the Applicability section of MOD-29 would already exclude ERCOT from compliance "so long as" ERCOT does not use the Rated System Path Methodology. While the SDT can establish Applicable Entities, it cannot determine liability on ERCOT's part for failure to adhere to a Standard. Assigning liability is outside the scope of this SDT. FERC has made it clear that where an entity believes they are exempt for regional differences the regional variance process is available.			

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-029-1.

Summary Consideration: Varied.

Question #10	
Commenter	**Comment**
WECC MIC MIS ATC TF	A. The current "R14." should be numbered as "R13.1." and this will have an impact on all subsequent requirements. B. 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 into each Standard in which it appears. C. R1. Change the determinant from "the" to "a" in the parenthetical. D. I n the "Applicability" section, either "Planning Coordinator" needs to be defined and imported into the NERC Glossary or a more appropriate entity such as "Planning Authority" may be in order.agreed E. R6. The term "extreme" is overly vague. This Team suggests replacement with the words "maximum or minimum". F. R7-R8. Change "posted path" to "Posted Path". As with MOD-08, Posted Path should be defined as: Posted Path Posted Path means: 1) any Balancing Authority to Balancing Authority interconnection; 2) any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; 3) and any path for which a customer requests to have ATC or TTC posted. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted. (Plagiarized from NAESBE R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. G. The term "postbacks" appeared in Order 890, P. 212. "Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows." Since the term is not defined and whereas FERC did not specify exactly what it is, the NERC Team should clarify what FERC meant by the term before inserting it into the calculation process. H. R6. Everytime the word "path" is used it should be replaced with "POSTED PATH." agreed I. To assist the industry in determining which of the three methodologies is best suited for the TSP's needs, it is suggested that a statement be inserted into the "Purpose" section of MOD-28 / 29 / 30 stating its intended use. E.g. MOD-28 was modeled on the ATC process of much of the Eastern Interconnect.

Question #10	
Commenter	**Comment**
	MOD-29 was modeled on the ATC process of much of the WECC Interconnet. J. R12.5 Delete "five years or longer in duration."
Response: A. Agreed. R14 should have been numbered as R13.1 – the content of R13 has been converted into an algorithm in the revised standard. B. Agreed. The drafting team added a definition for Available Transfer Capability Implementation Document. The term is introduced in MOD-001 and is defined in the revised version of MOD-001. C. Agreed. This change is reflected in the revised standard – see R2,6. D. Agreed. The Planning Coordinator is the same entity as the Planning Authority – just a new name introduced in Version 3 of the Functional Model. The drafting team will post a definition for the Planning Coordinator. Note that the RC has been supplanted by Transmission Operator in this standard. E. R6 was revised and now requires the determination of the 'maximum' flow in support of your suggestion. F. Agreed. The drafting team adopted the defined term, 'Posted Path' and has used this in the revised set of ATC-related standards. G. Agreed. We have asked NAESB to define this term, as we believe that Post Backs are commercial in nature. H. Agreed. The drafting team adopted the defined term, 'Posted Path' and has used this in the revised set of ATC-related standards. I. Agreed. All of the Purpose statements were modified to include a reference to the associated methodology as proposed. J. Agreed. The reference to 'five years or longer in duration' was removed from what had been R23.5.	
APPA	The Standard is written much like a Policy and it cannot be determined who is responsible for the different calculations of the components of the ATC. The Standard does not provide the Compliance Monitor or the TSP who calculates the Hourly. Daily, and Monthly ATCs with the necessary requirements to know what is necessary to be compliant.
Response: We have modified the standard to address this concern.	
BCTC	Requirements R3, R4, R5, and R6 are similar to what we are required to do under FAC-010-1. Similarity is good, but in this case there are areas of duplication and inconsistency. For example: 1. FAC-010-1 requires Planning Authorities to have an SOL Methodology that reflects the requirements similar to R3 and R4. Is NERC proposing that they will audit on having an SOL Methodology consistent with FAC-010 and then audit on determining TTCs consistent with MOD-029. What happens if our SOL Methodology differs from MOD-029? It seems that the TTC standard should only require to determine TTCs based on SOLs, which is what FAC-012 requires.

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Commenter	**Comment**
	2. Requirement R5 requires the use of assumptions consistent with expansion planning analysis. It is unclear what this means or how this would be audited, except by looking at SOL Methodology, unless we are also required to document our assumptions for MOD-029. This would be duplicative of our SOL Methodology. 3. Requirement R6 is not acceptable because it limits what we can consider in determining TTCs. R6.1, which references TPL-001 and TPL-002, is somewhat consistent with FAC-010. However, the reference should be to FAC-010, System Operating Limits, not the transmission planning standards. TPL-001 and TPL-002 do not have Western Interconnection differences, and TTCs need to allow for consideration of regional differences. Furthermore, we have to ask what is the purpose of BCTC having an SOL Methodology (FAC-010) and determining SOLs according to this Methodology (FAC-014), if MOD-029 provides criteria for determining TTCs. This is setting us up for a reliablity vs. commercial capacity conflict. 4. The second bullet under R6.1 is not acceptable. If a path is flow limited to less than "the reliability limit", how can we provide TTC up to the reliability limit. Firstly, we cannot calculate a reliability limit for anything higher than what will flow on the path (without using fictitious devices). Secondly, how can a customer use it? 5. Our suggestion to NERC would be to follow the structure layed out in the FAC series. Transmission Owners determine Facility Ratings according to FAC-008 and 009. Based on these Facility Ratings and other factors, Planning Coordinators, Reliability Coordinators, Transmission Planners determine SOLs according to FAC-010, 011,and -014. Based on these SOLs, PCs, RCs, and TSPs determine TTC, etc. according to the applicable NERC standard. The above comments are also applicable to MOD-28-1 and MOD 30-1.

Response:

(1) BCTCs suggestion is well received, and the drafting team added the following requirement to the revised standard to address this concern.

- R4. Each Transmission Operator shall establish the TTC as the lesser of the TTC calculated in MOD-029-1 or any System Operating Limit for that Posted Path.)

The SDT concurs that, much like FAC-10, FAC-11 (and FAC-12) as proposed for FERC approval FERC (), language needs to be added to MOD-29 stating that TTC shall not exceed the SOL. Restated, the TTC predicated on the TPL approach shall not exceed the SOL as determined in the FACs. "The TTCs shall respect all applicable System Operating Limits."

As FERC has pointed out, ATC is both a commercial as well as a reliability issue. A series of checks and balances is created by predicating the MOD-29 TTC on the proposed TPL method tempered by the SOLs as suggested by BCTC. By predicating the TTC on the proposed TPL methodology, a more robust TTC figure is calculated thereby prompting full utilization of the grid. By contrast, when that same TTC value is filtered through the SOL value, as BCTC suggests, system reliability keeps TTC in check and prompts over utilization. In no way does establishment of TTC via the proposed TPL-001 and TPL-002 methodology infringe on BCTC's need nor obligation to continue to calcuate an SOL. Both are needed.

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Commenter	**Comment**
As for the substantive requirements of FAC-12 and FAC-13, the SDT is importing these into the ATC-related MOD standards and proposing 12 and 13 be retired. B. (2) R5 was inserted in the standard to satisfy a directive in Order 890 (P.292). The SDT has moved R5 into MOD-001. R8 was added to the revised MOD-001 to ensure that, whatever method is used to calculate TTC, TFC or ATC, the assumptions used must be consistent with those used in any associated operations or planning studies for the time period being studied. C. (3) MOD-28, 29 and 30 were not specificially designed to include all features of the ATC calcuation for any specific RRO. Although the TPL approach proposed in the first draft of proposed revisions to MOD-029, did not directly incorporate all of WECC's regional differences, by using TPL-001 and TPL-002, the standard mimiced WECC's Path Rating approach at a high level thus allowing non-WECC entities a proper umbrella for inclusion should they decide to select the RSP. The drafting team modified R6 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:") D. (4) The SDT modified the second bullet under R6 in support of your suggestion – in the revised standard, this is R2.2: R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. E. (5) The SDT reviewed the Applicability section in light of the NERC Functional Model and has assigned Applicable entities based on the Model and the Team's best understanding of the activities assigned. In the revised set of standards, the Transmission Operator is assigned responsibility for determining TTC and the Transmission Service Provider is assigned responsibility for determining ATC.	
BPA	The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies. The Applicability section 4.1. through 4.3. and R1., R4. through R11., R15., and R16. should be clarified that ATC need only be calculated and posted for Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60. agreed R2. and R9. -- Making TTC study reports publicly available would present system security concerns due to the fact that such studies will identify the most limiting contingencies. Identifying the most critical contingencies publicly could make them a target and thus reduce system reliability. This information should only be shared with those

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	entities demonstrably impacted by such limiting contingencies. R12.7. and R14.5. -- Please define the term "Post-back". The current "R14." should be numbered as "R13.1." and this will have an impact on all subsequent requirements.
Response: The purpose statement of MOD-028, MOD-029 and MOD-030 was revised to include a description of the associated methodology – and each of the methodologies has been defined. The Reliability Standards Development Procedure does not have a place, other than in definitions and reference documents, for inclusion of narrative descriptions. "Posted Path" concept has been adopted and is used extensively in the set of revised standards. As to the confidentiality concerns, the drafting team removed all requirements in the standards that used the term, 'make publicly available' - NAESB will be addressing any public release of information. As to "post back", the SDT agrees. NAESB is developing a definition for this term. As to R14, the SDT concurs that The version of the standard posted for comment was not numbered correctly. In the revised standard, the content of R13 has been placed into an algorithm and there are no sub-requirements.	
Entergy	R1- it is not clear which "report drafted for a TTC study" is referred to and what study is conducted. R3 - "critical modeling details" is vague and should be explained. R3 and R4 - it appears that only one model is used for calculation of TTC for all paths and time horizons, if yes, it appears unrealistic, if no, model should be made plural. R4 - are Long Term Firm Transmission Service Reservations included in base cases? If so, these should be included as subrequirement under R4. R4 - R4 should include planned and unplanned outages, if included in the base case. R6.2 refers to path rating - is it same as TTC of that path, if so, only TTC based on path rating should be used. R6.2, it is not clear what is "revised path". R6.2 second bullet - are local or regional procedures approved by any entity? These should be included in the data to be made publicly available and included in R9.

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	R8 - it appears like each Planning Coordinator determine TTC for all posted path of Transmission Service Provider. "value" should be made plural. It is not clear how frequently TTC values are calculated or updated.

Response:

R1 – SDT agrees. This has been corrected in the revised standard by rearranging the sequence of requirements so that all steps associated with determining TTC are in a single requirement. Putting together a report that includes the TTC and its associated assumptions, etc is now part of R2. The new sub-requirement refers to the report as a "study report," providing detail as to what goes in the study report
R3 – SDT agrees. This requirement has been clarified by the following rewording and is R1 in the revised standard:

> When calculating TTC for Posted Paths, the Transmission Operator shall use a Transmission model the meets the following criteria:

R3-R4 – There is a separate study for each path for each time period using a separate model if deemed appropriate. The WECC coordinated base cases are usually the seed cases for building these models. Although normally the same model is not used to conduct all TTC studies since R3 & R4 reference model in a generic sense the SDT feels that using the word "model" in the singular form is appropriate.
R4 - Initially, they are included but since generation and load can be adjusted to maximize stress on the path of interest they are not very relevant. TTC studies are case specific or outage specific. A special study will be run if the TTC for a particular outage condition is of interest.
R6.2 – Path Rating and TTC are the same thing in WECC vernacular. You are correct that we should be using the word "TTC" instead of "path rating" for this section of the standard to avoid confusion, and we've modified the standard in support of this suggestion. See the use of the acronym, TTC instead of 'path rating' in the revised standard's Requirement 2.
R6.2 "Revised path" is a Posted Path that has been revised. Note that the requirement to make the study results publicly available has been deleted as all posting requirements are being addressed by NAESB as business practices.
R8 - The SDT believes the correct role for this task is actually the "Operations Planner," a role that does not exist in the functional model at this time. The SDT has requested a new role of "Operations Planner" utilizing the Functional Model. In the interim, the term Transmission Operator has supplanted Operations Planner.

TTC will be calculated as necessary to support the requirements for ATC specified in MOD-001.

FirstEnergy	R6.2 demonstrates the essential difference with Network Response ATC calculations. R11 should be revised to eliminate the subtraction of a portion of TRM from TTC to calculate ATC since this has

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Commenter	Comment
	already occurred in R6.2 where parallel path impacts are covered.

Response:
The drafting team modified the standard so that it includes algorithms for the determination of ETC and ATC. The revised standard includes the following algorithm for the determination of firm ATC, and it does subtract TRM from TTC as proposed:

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + Counter\text{-}schedules_F$$

Commenter	Comment
NPCC HQTE	For Clarification: R6.1 Regional criteria (NPCC) are not all included in TPL-001 and TPL002 for contingencies in Table 1, category B…There should be acknowledgement that there can be regional differences in the application of planning criteria that may extend beyond Category B contingencies in determination of TTC. R.12.10 (re-numbered to R13) : Note that the TRM allocated to the path for non-firm ATC may be less than the TRM for firm ATC. R12.10 (renumbered to R13): As it is not specified , we understand that the TSP is free to calculate the ATC by reducing the TTC by reserved or by scheduled transmission services depending on the time horizon. R11: Use of the word "impact" in the formula for ATC introduces confusion. Can R11 be written in formula format like the Version Zero standards? R11.4 Use of the word "impact" is redundant.

Response:
R6.1 – The drafting team modified R6.1 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:")

R.12.10 was converted into a requirement to use an algorithm to determine non-firm ETC – here is the algorithm:

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for a Posted Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

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	$NITS_{NF}$ is the non-firm capacity reserved for Network Integration Transmission Service serving Load, to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin. **GF_{NF}** is the non-firm capacity reserved for grandfathered Transmission Service and bundled contracts for energy and Transmission, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "Safe Harbor Tariff" accepted by FERC. **PTP_{NF}** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service. **OS_{NF}** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm. R.11 – Agreed. The term "impact" has been removed and the descriptive language was converted into an algorithm similar to the one above for R12.10.
IESO	Please see our comments on the supplementary SAR will be addressed in response to sup sar
Response: Please see the team's response to the comments on the supplementary SAR.	
IRC	Please see our comments on the supplementary SAR. will be addressed in response to sup sar
Response: Please see the team's response to the comments on the supplementary SAR.	
ERCOT	See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.	
MEC	Our footprint does not include facilities in the WECC, therefore, I do not answer all the questions on the MOD-029-1 but provides the following comments: 1. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The purpose in MOD-028-1 be revised to replace "uniform" with "transparent". 2. The Functional Entity as provided in A.4. should not be qualified, for example, A.4. should just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. 3. For R1, R3, R4, R5, R6, R7, and R8, 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

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Commenter	**Comment**
	appropriate", do these requirements in the standard. 4. R6.1 refers to only certain NERC planning criteria, when the TTC must be based upon the appropriate planning criteria whatever that is. The references to planning criteria should be expanded to include all applicable planning criteria, including NERC, regional, subregional, Transmission Owner, etc. 5. R2, R9, R16 and 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. 6. R12 should be revised to indicate that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropriate level of " the following inputs. 7. R14 should be renumbered R13.1 and R14.1 through R14.5 should be renumbered R13.2 through R13.6. R15 and R16 should be renumber R14 and R15. 8. Existing transmission commitments should be listed without capital letters or else it needs to be defined for the NERC Glossary.

Response:
(1) Agreed; the drafting team modified the purpose statements in MOD-28, 29, 30 to include a reference to the associated methodology and to clarify that the purpose was to increase consistency and transparency.
(2) The qualifiers used in the Applicability section clarify which entities are being held responsible for the various requirements. The qualifying language is included in support of the Reliability Standards Development Procedure.
(3) The SDT modified the Applicable entities to more closely align with the Functional Model – the Transmission Operator has been assigned responsibility for determining TTC or TFC and the Transmission Service Provider has been assigned responsibility for determining ATC. This change was made in MOD-028, MOD-029 and MOD-030. The SDT disagrees that MOD-29 presumes the existence of an RTO.
(4) The drafting team modified R6.1 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:")
(5) The SDT agrees; however, R2, R9 and R16 have been removed from the revised standard as all posting issues are being addressed by NAESB in business practices.. The SDT will advise NAESB of your comments.
(6) R12 was revised now states:

When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for a Posted Path, the

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Commenter	**Comment**
Transmission Service Provider shall use the following algorithm: (7) The SDT concurs that renumbering / restructuring would have added clarity to the standard. The format of the revised standard is quite different, and the requirements for calculation of ETC and ATC include specific algorithms and don't have any sub-requriements. (8) The SDT agrees. A defintion for ETC has been included with the revised version of MOD-001.	
MRO	The MRO footprint does not include facilities in the WECC, therefore, the MRO does not answer all the questions on the MOD-029-1 but provides the following comments: 1. The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The MRO recommends that the purpose in MOD-028-1 be revised to replace "uniform" with "transparent" 2. The MRO believes that the Functional Entity as provided in A.4. should not be qualified, for example, the MRO recommends that A.4. just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. 3. The MRO believes that for R1, R3, R4, R5, R6, R7, and R8, 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. 4. R6.1 refers to only certain NERC planning criteria, when the TTC must be based upon the appropriate planning criteria whatever that is. The references to planning criteria should be expanded to include all applicable planning criteria, including NERC, regional, subregional, Transmission Owner, etc. 5. R2, R9, R16 and 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. 6. R12 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. 7. R14 should be renumbered R13.1 and R14.1 through R14.5 should be renumbered R13.2 through R13.6. R15 and R16 should be renumber R14 and R15. 8. Existing transmission commitments should be listed without capital letters or else it needs to be defined for the

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Commenter	**Comment**
	NERC Glossary.

Response: (1) Agreed; the drafting team modified the purpose statements in MOD-28, 29, 30 to include a reference to the associated methodology and to clarify that the purpose was to increase consistency and transparency.
(2) The qualifiers used in the Applicability section clarify which entities are being held responsible for the various requirements. The qualifying language is included in support of the Reliability Standards Development Procedure.
(3) The SDT modified the Applicable entities to more closely align with the Functional Model – the Transmission Operator has been assigned responsibility for determining TTC or TFC and the Transmission Service Provider has been assigned responsibility for determining ATC. This change was made in MOD-028, MOD-029 and MOD-030. The SDT disagrees that MOD-29 presumes the existence of an RTO.
(4) The drafting team modified R6.1 so that the specific reference to the TPL standards (". . .while at the same time satisfying the planning criteria in TPL-001 and TPL-002 for the Contingencies in Table 1, Category B or the successor criteria.") was replaced with more generic language to achieve the same purpose (". . .while at the same time satisfying all planning criteria for N-0, N-1, and N-2 contingencies as follows:")
(5) The SDT agrees; however, R2, R9 and R16 have been removed from the revised standard as all posting issues are being addressed by NAESB in business practices.. The SDT will advise NAESB of your comments.
(6) R12 was revised now states:

> When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for a Posted Path, the Transmission Service Provider shall use the following algorithm:

(7) The SDT concurs that renumbering / restructuring would have added clarity to the standard. The format of the revised standard is quite different, and the requirements for calculation of ETC and ATC include specific algorithms and don't have any sub-requriements.
(8) The SDT agrees. A defintion for ETC has been included with the revised version of MOD-001.