NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Modifications made 11/1/07 to this page and page 36.

Consideration of Comments on 1st Draft of Standard MOD-004-1 — Capacity Benefit Margin (Project 2006-07)

The ATC Standard Drafting Team thanks all commenters who submitted comments on Draft 1 of the MOD-004-1 Capacity Benefit Margin. This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special standard Comment Form.

There were 20 sets of comments, including comments from 97 different people from more than 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

- Added two defined terms: Generation Capability Import Requirement (GCIR) and Capacity Benefit Margin Implementation Document (CBMID)
- Revised the proposed definitions of Flowgate, Total Flowgate Capability, and Available Flowgate Capability – but moved these definition to the draft MOD-030 standard
- Eliminated Transmission Reservation and Transmission Service Request as proposed defined terms
- Modified the Purpose statement to clarify that the purpose is to ensure reliable system operations rather than accurate calculation of transfer capabilities
- Adopted the use of the defined term, 'Posted Path' to match the definition used by FERC and NAESB (without the explanatory information at the end of the definition)
- Modified the description of the Load-Serving Entities that must comply with the standard so that the standard now applies to all Load-Serving Entities. While the standard does not require that all LSEs must request CBM, it does allow any Load-Serving Entity to use CBM in a capacity deficiency emergency even if they did not originally request to have it set aside. (They would, however, only be allowed to use CBM if those, who originally asked for it, were not using it).
- Modified R1 so that it requires a Capacity Benefit Margin Implementation Document rather that includes a set of procedures rather than just identifying the list of procedures
- Eliminated the posting elements of R1 and R2 as NAESB will address all public postings in its associated business practices but retained the other aspects of the requirements.
- R2 which required the Transmission Service Provider to make copies of its models used to determine CBM available to others has been modified and merged into R7 in the revised standard.
- Added more details to R3 to clarify that the Transmission Service Provider must first determine the amount of CBM to allocate for each CBM request, then set CBM for each

Posted Path or Flowgate according to a set of criteria. The revised requirement (R4 in the revised standard merges portions of R3 and R7.

- R4 required the Load-Serving Entity that wants CBM to submit a request for CBM at least annually. This requirement has been modified to expand on the scope of documentation that must be provided to support the request for CBM. For example, in the revised requirement the Balancing Authority that has the generation to be imported must be identified, resource studies that show the need for CBM must be provided, etc. A sub-requirement was added to require the Load-Serving Entity to update its CBM request at least once every 31 days.
- R5 was structured as a data retention requirement for the Load-Serving Entity. Many of the items listed have been moved into the revised R3 and must be supplied to the Transmission Service Provider with the request for CBM. The drafting team deleted the data retention aspect from the requirement. Data retention is addressed in the compliance section of the revised standard and is identified on a requirement-by-requirement basis.
- R6 required the Load-Serving Entity to follow certain steps if it performed probabilistic studies for determining CBM import MW requirements and the drafting team removed the requirement from the revised standard. The revised standard assumes that studies have been conducted and requires the results of the studies be provided with a request for CBM, but the revised standard does not identify 'how' to perform these studies.
- R7 was merged into the revised R3. The portion of R7 that required the Transmission Service Provider to make a CBM Import Entitlement Report 'publicly available' has been removed from the revised standard. NAESB is developing business practices to address all of the 'posting' requirements associated with the set of ATC-related standards.
- R8 stated an 'allowance' for the Load-Serving Entity to request CBM under certain conditions. The requirement did not include a statement of required performance and several commenters indicated it was difficult to understand. The drafting team removed this from the revised standard.
- R9 required the Balancing Authority to waive timing and ramping requirements for scheduling of energy over transmission capacity set aside as CBM. This requirement was revised to require both the Balancing Authority and Transmission Service Provider to adhere to this requirement.
- R10 required the Load-Serving Entity to declare a NERC Energy Emergency Alert (EEA) level 2 before scheduling energy over transmission capacity set aside as CBM. This requirement was modified to clarify that it is not the Load-Serving Entity that 'declares' the EEA, but the Load-Serving Entity is 'experiencing' an EEA level 2. (See R8 in the revised standard)
- R11 required the Load-Serving Entity to provide a report to its Transmission Service Provider after scheduling energy over transmission capacity set aside as CBM and to retain that report for five years. The drafting team removed this requirement as any reporting requirements can be addressed under the compliance section of the standard as 'Exception Reporting'.
- R12 required the Transmission Service Provider to make the report from R11 'publicly available' and since the report is no longer required and NAESB is addressing all posting requirements, this requirement was removed from the revised standard.
- R13 required the Transmission Planner to consider CBM import MW requirements in its planning processes. This requirement has been merged into ~~R4~~ R5 and more details have been added to the requirement for the Transmission Planner.

- R14 required the Load-Serving Entity to avoid use of the same uncertainties for both CBM and TRM. A similar requirement is within MOD-008 — Transmission Reliability Margin and the drafting team removed R14 from MOD-004 to avoid having the same requirement in more than one standard.
- 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/Backup_Facilities.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 (G5)	AESO		✓								
2.	Jason Murray (G1)	AESO		✓								
3.	Darrell Pace (G9)	Alabama Electric Coop				✓	✓	✓				
4.	Heln Stines (G9)	Alcoa Power Generating						✓	✓	✓		
5.	Ken Goldsmith (G6)	ALT	✓				✓					
6.	Eugene Warnecke (G9)	Ameren			✓			✓				
7.	E. Nick Henery (G2)	APPA	✓									
8.	Jerry Smith (G1)	APS-TP										
9.	Dave Rudolph (G6)	BEPC	✓		✓		✓	✓				
10.	Steve Tran (G1)	BP TX										
11.	Abbey Nulph (G1) (I)	BPA	✓		✓		✓	✓				
12.	Rebecca Berdahl (G1)	BPA	✓		✓		✓	✓				
13.	Steve Knudsen (G1)	BPA	✓		✓		✓	✓				
14.	Charles Mee (G1)	CA Dept Water & Power										
15.	Greg Ford (G1)	CISO-TP		✓								
16.	Don Reichenbach (G9)	Duke Energy	✓		✓		✓	✓				
17.	Greg Rowland	Duke Energy	✓		✓		✓	✓				
18.	Joachim Francois (G9)	Entergy	✓		✓		✓	✓				
19.	Ed Davis (G3)	Entergy Services	✓		✓		✓	✓				
20.	George Bartlett (G3)	Entergy Services	✓		✓		✓	✓				
21.	Jim Case (G3)	Entergy Services	✓		✓		✓	✓				
22.	Narinder Saini (G3)	Entergy Services	✓		✓		✓	✓				
23.	Steve Myers (I) (G5)	ERCOT		✓								✓
24.	Patricia vanMidde (G1)	FERC Case MRG, Sempra										
25.	Dave Folk (G4)	FirstEnergy	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
26.	Phil Bowers (G4)	FirstEnergy	✓		✓		✓	✓				
27.	Richard Kovacs (G4)	FirstEnergy	✓		✓		✓	✓				
28.	Ross Kovacs (G9)	Georgia Transmission Co	✓		✓							
29.	Joe Knight (G6)	Great River Energy	✓		✓		✓					
30.	Ron Falsetti (I) (G5)	IESO		✓								
31.	Lou Ann Westerfield (G1)	IPUC-SP										
32.	Matt Goldbert (G5)	ISO New England (ISO NE)		✓								
33.	Rian Thumm	ITC	✓									
34.	Sueyen McMahon (G1)	LADWP	✓		✓		✓	✓				
35.	Eric Ruskamp (G6)	LES	✓		✓		✓					
36.	Michelle Rheault	Manitoba Hydro	✓		✓		✓	✓				
37.	Robert Coish (G6)	Manitoba Hydro	✓		✓		✓	✓				
38.	Tom Mielnik (I) (G6)	MidAmerican Energy Co (MEC)			✓							
39.	Dennis Kimm	MidAmerican Energy Generation/Trading (MEC – Trading)			✓		✓	✓				
40.	Larry Middleton (G9)	Midwest ISO										
41.	Bill Phillips (G5)	MISO		✓								
42.	Terry Bilke (G6)	MISO		✓								
43.	Carol Gerou(G6)	MP	✓		✓		✓	✓				
44.	Mike Brytowski (G6)	MRO										✓
45.	Jerry Tang (G9)	Municipal Electric Authority of GA	✓		✓		✓					
46.	Jerry Teag	Municipal Electric Authority of GA (MEAG)	✓		✓		✓					
47.	Matt Schull (G2)	NCMPA #1					✓					
48.	Robert W. Creighton	Nova Scotia Power, Inc	✓									
49.	Jim Castle (G5)	NYISO		✓								
50.	Todd Gosnell (G6)	OPPD	✓		✓			✓				
51.	Brian Weber (G1)	Pacificorp	✓				✓					
52.	C. Robert Moseley (G7)	PSC of SC									✓	
53.	David A. Wright (G7)	PSC of SC									✓	
54.	G. O'Neal Hamilton (G7)	PSC of SC									✓	
55.	John E. Howard (G7)	PSC of SC									✓	
56.	Mignon Clybum (G7)	PSC of SC									✓	
57.	Phil Riley (G7)	PSC of SC									✓	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
58.	Randy Mitchell (G7)	PSC of SC									✓	
59.	Chuck Falls (I) (G1)	Salt River Project (SRP)	✓									
60.	Al McMeekin (G9)	SC Electric & Gas			✓		✓	✓				
61.	Stan Shealy (G9)	SC Electric& Gas			✓		✓	✓				
62.	Carter Edge (G9)	SERC										✓
63.	John Troha (G9)	SERC										✓
64.	Bob Schwermann (G1)	SMUD	✓		✓		✓	✓				
65.	Brian Jobson (G1)	SMUD	✓		✓		✓	✓				
66.	Dick Buckingham (G1)	SMUD	✓		✓		✓	✓				
67.	Dilip Mahendra (G1)	SMUD	✓		✓		✓	✓				
68.	W. Shannon Black (G1)	SMUD	✓		✓		✓	✓				
69.	Phil Odonnell (G1)	SMUD- Ops	✓		✓		✓	✓				
70.	Bill Botters (G8)	Southern Company Services	✓				✓					
71.	Bryan Hill (G9)	Southern Company Services					✓					
72.	Chuck Chakravarthi (G8)	Southern Company Services	✓				✓					
73.	Dean Ulch (G8)	Southern Company Services	✓				✓					
74.	DuShane Carter (G8) (G9)	Southern Company Services	✓				✓					
75.	Garey Rozier (G8)	Southern Company Services					✓					
76.	Gary Gorham (G8)	Southern Company Services	✓				✓					
77.	J. T. Wood (G8)	Southern Company Services	✓				✓					
78.	Jeremy Bennett (G8)	Southern Company Services	✓				✓					
79.	Jim Howell (G8)	Southern Company Services	✓				✓					
80.	Jim Viikinsalo (G8)	Southern Company Services	✓				✓					
81.	Karl Moor (G8)	Southern Company Services	✓				✓					
82.	Marc Butts (G8)	Southern Company Services	✓				✓					
83.	Reed Edwards (G8)	Southern Company Services	✓				✓					
84.	Roman Carter (G8)	Southern Company	✓				✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Services										
85.	Ron Carlsen (G8)	Southern Company Services	✓				✓					
86.	Charles Yeung (G5)	SPP		✓								
87.	Casey Sprouse (G1)	Sr. Term Marketer										
88.	Maria Denton (G1)	SRP										
89.	Terri M. Kuehneman (G1)	SRP System Operation										
90.	Raquel Agular (G1)	Tucson	✓		✓		✓	✓				
91.	Ron Belval (G1)	Tucson	✓		✓		✓	✓				
92.	Doug Bailey (G9)	TVA	✓		✓		✓					
93.	Jim Haigh (G6)	WAPA	✓								✓	
94.	Raymond Vojdani (G1)	WAPA									✓	
95.	Mike Wells (G1)	WECC										✓
96.	Neal Balu (G6)	WPS			✓	✓	✓	✓				
97.	Pam Oreschnick (G6)	XEL	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – WECC MIC MIS ATC Task Force
G2 – APPA
G3 – Entergy Services
G4 – FirstEnergy
G5 – IRC Standards Review Committee
G6 – MRO
G7- PSC of SC
G8- Southern Company
G9- SERC ATC WG

Index to Questions, Comments, and Responses

1. **The drafting team combined the topics of MOD-004-0, MOD-005-0, MOD-006-0, and MOD-007-0 into the draft MOD-004-1 in an attempt to make the standard easier to follow. Do you agree with the drafting team's decision to combine all the requirements for Capacity Benefit Margin calculation, verification, preservation, and use into a single standard? If "No," please explain why in the comments area.**

Summary Consideration: Most stakeholders who responded to this question indicated a preference for keeping the requirements in a single standard. Based on responses received, the drafting team has retained the requirements in a single standard.

Question #1			
Commenter	**Yes**	**No**	**Comment**
BPA		☑	R1 of MOD-004-1 needs to clarify that CBM procedures need only be made publicly available if the Transmission Service Provider uses CBM.
Response: All public posting requirements will be addressed by NAESB, however, FERC has indicated that the TSP must offer CBM to its LSEs, and as such, the standard requires all TSPs to prepare and maintain CBM procedures.			
IESO IRC SRC		☑	We do not agree with combining all of the above mentioned standards in one standard (MOD-004). This coupled with the need to make a distinction between the ATC calculation methods used and the descriptive procedure for resource adequacy assessment has made the new MOD-004 very convoluted, and the requirements difficult to follow and measured. If combining some standards of related objective is desired, a more manageable and appropriate alternative is to divide these 4 standards into two groups - one on the determining and verifying the calculation of CBM and the other on the use and reporting of use of CBM.
Response: Based on stakeholder responses received, the consensus is to keep the single standard. Note that several requirements have been removed from the revised standard, including the requirements referencing resource adequacy.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.			
ITC	☑	☑	We highly recommend sticking to one single standard to address all of the CBM requirements.
Response: Most responders agree and based on stakeholder responses received, the consensus is to keep the single standard.			
Entergy Services	☑		Entergy supports combination of CBM Calculation, verification, preservation, and use into one standard.
Response: Most responders agree and based on stakeholder responses received, the consensus is to keep the single standard.			
Duke Energy	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC Task Force	☑		
APPA	☑		
FirstEnergy	☑		
MEAG	☑		
MEC Trading	☑		
MEC	☑		
MRO	☑		
Nova Scotia Power	☑		
PSC of SC	☑		
Southern Co Svcs	☑		
SERC ATCWG	☑		

2. **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 CBM (summarized in Attachment 1). Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to CBM in this draft of MOD-004-1? If "No," please explain why in the comments area.**

Summary Consideration: Most stakeholders who responded to this question indicated that the drafting team has adequately responded to all of the Commission's directives in Order 890 and 693, however there were some suggestions for modifications that would improve compliance with the directives.

Question #2			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The Standard, as written, will continue to allow the applicable functions to define CBM without any amount of consistency, which is what Order 890 wanted the Standards to accomplish. In addition, the Standard does not recognize that ATC is calculated on 3 different time horizons and CBM transmission reservation will vary from the Monthly to the Daily to the Hourly calculations.
Response: The standard requires the LSE "prove" and document its need for CBM. It is quite possible that these requirements will not be consistent across the country. By law, the ERO cannot determine these requirements but is fully responsible for ensuring that the LSE is stating these requirements accurately as determined by "the entity responsible for establishing the Load-Serving Entity's resource adequacy requirements." However, it is expected that most requirements will be based on some LOLE requirement. The compliance monitor (now called the Compliance Enforcement Authority) will be required to ensure that the LSE is not deviating from the resource adequacy requirements of the "entity responsible" for these requirements.			
MEC Trading MEC MRO		☑	1. R3.1.2, R3.2.1, and R3.3.1 should be clarified by matching the language in FERC 890 as follows: "The Transmission Service Provider shall not include transmission capacity set aside for THE INCREMENTAL POWER FLOWS RESULTING FROM reserve sharing in CBM." It could be that CBM is reserved to the LSE's generation reliability criteria which is based upon a reserve sharing requirement. It is just that those flows that result from increment power flows resulting from reserve sharing are to be included in TRM. 2. In R1.1, it would be better to include the exact language from Order 890 in the parantheses to explain the resource adequacy requirements that are to be included in the CBM, as follows: "…..for meeting its resource adequacy requirement (i.e., its procedure for setting aside of Transfer Capability in the form of CBM to MEET a Load-Serving Entity's GENERATION RELIABILITY CRITERIA.) 890 and 693 also require some level of consistency and the methodology requirements for CBM appear to be fill-in-the-blank.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: 1.) The drafting team agrees that this is what FERC intended. Please see the revised requirement in the summary consideration above. As defined, CBM is a transaction and you can't subtract flows from transactions. In the revised standard's R4.2.1, we subtract "the transfer capability set aside for reserve sharing" because this is a transaction quantity. Posted Paths are transaction paths (ATC) In 4.2.2 we subtract "the 'impact' of transfer capability set aside for reserve sharing. The "impact" is a flow quantity. Flowgates use "flows" and not transactions (AFC). This "impact" equals what FERC calls the "incremental power flows resulting from reserve sharing". 2.) The existing language is appropriate based on FERC's use of the term in attachment C, paragraph e of the pro-forma OATT included with Order 890. The standard drafting team has attempted to increase the consistency of CBM determination in the latest revision. Please see the summary of changes to requirement on the cover page of this report.			
Nova Scotia Power	☑	☑	What happened to the requirement that CBM is a planning quantity only and tends to zero in the operating horizon. Does this mean that CBM cannot be used for non-firm import transactions?
Response: This requirement has been addressed in the specific ATC standards, such that non-firm ATC is increased by unscheduled CBM. (See the algorithms for the determination of ATC and AFC in MOD-028, MOD-029 and MOD-030.)			
IESO IRC SRC	☑		In a general sense, yes, but the amount of detail seems to exceed the requirements implied by the FERC directives, which has resulted in repetitions and circular requirements. For example, R5 repeats most of R4's requirements, except in R5 the retention periods are specified, which arguably should be covered in the compliance section. Another example is R6.1 suggests that the CBM is calculated as a parameter or a by-product of a resource adequacy assessment, but R6.2 requires that the load assumption of the CBM study be the same as that assumed in the the resource adequacy assessment.
Response: You are correct in that CBM is a by-product of resource adequacy assessments required by whatever entity directs the LSE to meet their requirements. The standard drafting team has attempted to clarify and improve the standard to consolidate where possible. R5 was deleted and is addressed in the compliance section of the standard under data retention. R6 was also deleted from the revised standard.			
ERCOT	☑		See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.			
Duke Energy	☑		
Entergy Services	☑		

Question #2			
Commenter	**Yes**	**No**	**Comment**
FirstEnergy	☑		
ITC	☑		
PSC of SC	☑		
Southern Co Svcs	☑		

3. **The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-004-1 standard and expanded the applicability section of the CBM standard to include all applicable entities. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to and why.**

Summary Consideration: Most commenters who responded to this question supported the applicability section of the standard – there were suggestions to remove the 'qualifying language' associated with the Load-Serving Entity, and the drafting team has removed this qualifying language – the revised standard is applicable to all Load-Serving Entities. There were also some suggestions to clarify the responsibilities of the Transmission Planner. As revised, the Transmission Planner is responsible for two requirements – for allocating CBM for use in the long-term horizon (beyond one year) and for providing copies of the supporting data used to allocate CBM. The Drafting team has rewritten the standard to be more clear, and to explicitly explain the responsibilities of the Transmission Planner.

Question #3			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	All throughout this Standard the author has Reliability Functions performing duties that are counter to those duties prescribe in the Functional Model. In addition, the SDT has incorrectly included requirements for scheduling of energy, maintenance schedules, and so-on, which are preformed by other Reliability Functions in other Standards.
Response: We have attempted to address this in the new draft of the standard. Please see the summary of revisions made to the standard on the cover page of this document.			
MEC		☑	I believe that the Functional Entity as provided in A.4.1.1 should not be qualified, for example, A.4.1.1 should just list Load-Serving Entity. However, if the Standards Drafting Team continues to list only those "Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM" then I recommend that "would like" changed to "needed" in other words, reservation of CBM should not be based on likes but based on needs as demonstrated with the studies to be provided in support of the CBM.
Response: We have modified the applicability for the Load-Serving Entity to eliminate the qualifiers in support of your suggestion.			
MRO		☑	The MRO believes that the Functional Entity as provided in A.4.1.1 should not be qualified, for example, the MRO recommends that A.4.1.1 just list Load-Serving Entity. However, if the Standards Drafting Team continues to list only those "Load-Serving Entity that is entitled and would like to have transmission capability set aside in the form of CBM" then the MRO recommends that "would like" changed to "needed" in other words, reservation of CBM should not be based on likes but based on needs as demonstrated with the studies to be provided in support of the CBM.
Response: We have modified the applicability for the Load-Serving Entity to eliminate the qualifiers in support of your			

Question #3			
Commenter	**Yes**	**No**	**Comment**
suggestion.			
IESO IRC SRC		☑	There is only one requirement for the Transmission Planner, and that is in R13. However, we do not feel that R13 belongs to this standard. The inclusion of requested and projected CBM values in its planning process belongs to a standard that stipulate requirements for transmission planning. If this requirement is removed or relocated, then TP does not need to be included as an applicable entity. Similar thoughts for the applicability of the BA.
Response: We have rewritten the standard to more fully explain the role of the Transmission Planner. Note that the drafting team did ask stakeholders to weigh in on whether all requirements related to CBM should be contained within a single standard and most commenters indicated support for having all CBM-related requirements in the single standard.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.			
WECC MIC MIS ATC Task Force	☑		
Duke Energy	☑		
Entergy Services	☑		
FirstEnergy	☑		
ITC	☑		
MEAG	☑		
MEC Trading	☑		
PSC of SC	☑		
Southern Co Svcs	☑		
SERC ATCWG	☑		

4. **The drafting team created new CBM requirements and expanded or deleted some prior CBM requirements. Do you agree with the requirements identified in the draft standard MOD-004-1? If "No," please explain why in the comments area.**

Summary Consideration: Please see the cover page of this report for a complete list of the modifications made to the standard based on stakeholder comments and discussions with NAESB and FERC.

Question #4			
Commenter	**Yes**	**No**	**Comment**
BPA			The discussion of CBM in Order 890 and NERC's definition of CBM refer only to generation reliability requirements, not resource adequacy requirements. Please clarify what is meant by "resource adequacy requirements".
Response: The "resource adequacy requirement" is the same as the "planning" reserve margin as defined by "the entity responsible for establishing the Load-Serving Entity's resource adequacy requirements." For those entities with LOLE requirements, it is usually the LSE's dependence on external resources to meet those LOLE requirements. The drafting team did remove the resource adequacy requirements from the revised standard – the revised standard assumes that the studies have been conducted and requires that the study documentation be provided as part of the request for CBM.			
WECC MIC MIS ATC Task Force		☑	See general comments.
Response: See response to general comments.			
APPA		☑	The Standard has Functional Entities performing duties that is contrary to the Functional Model's directions. Examples are in Requirement R 1.3 and R 10; the scheduling of energy over the transmission capacity that is designated CBM only occur during the active hour to meet "generation reliability requirements." The Balancing Authority is the only Function that has that authority to schedule energy during the real-time. This Standard, as written, will create an environment where confusion will exist during critical situation in the real-time and cause the possibility of a command and control break down during a critical situation in the real-time. To require the Transmission Service Provider or the Load Serving Entity to be responsible for declaring emergencies or scheduling energy during those emergencies will create very non-reliable situation. A large part of this Standard needs to be rewritten to ensure reliable operations.
Response: Requirement 1.3 in the first draft of this standard required the Transmission Service Provider to document its procedure for an LSE to request CBM. The drafting team did not change the applicability for this requirement as it is the Transmission Service Provider that must have this procedure. R10 in the first draft of this standard required the Transmission Service Provider to declare a NERC EEA 2 – and this has been revised. In the revised standard, this requirement (now R8) clarifies that the LSE cannot request to schedule energy over Firm Transfer Capability set aside as CBM unless the LSE is experiencing a NERC EEA 2 . You are correct that it is not the			

Question #4			
Commenter	**Yes**	**No**	**Comment**
LSE that 'declares' the EEA 2. As revised, there are no requirements for the Transmission Service Provider or Load-Serving Entity to declare emergencies.			
IESO IRC SRC		☑	Please see the above comments on some of the repetitive and extraneous requirements.
Response: See responses to previous questions.			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See the response to IRC comments.			
MEAG		☑	R8.1 needs clarification.
Response: Several commenters indicated that R8.1 needs clarification and the intent of this requirement has been absorbed into R10 of the revised standard.			
MEC Trading		☑	Many of the requirements are fill-in-the-blank (Isn't R1.2 a requirement to "tell me how you do it? and shouldn't it be "this is how you do it")
Response: We have attempted to eliminate the fill-in-the-blank elements of the standard. The drafting team is trying to find the right balance between mandating that all entities perform the calculations the same way, and allowing some latitude for justifiable differences. As the standards are implemented and more documents become 'transparent' the standard may need to be revised to eliminate any 'fill-in-the-blank' elements if there is evidence that this flexibility is adversely impacting either reliabilty or energy markets.			
MEC		☑	1. I recommend that R2 be changed from "following a request by an entity with a valid need for such information" to "following a request by a Functional Entity with a valid need for such information, subject to security and confidentiality requirements." 2. R5.3 does not represent all the conditions that organizationally exist, therefore, I recommend that a bullet be added under R5.3 as follows" "Planning Reserve Sharing Group reserve margin to meet the Regional Reliability Organization resource adequacy requirements". 3. R6.2 should refer to "a load forecast that has a 50/50% probability of occurrence". This means that there is a 50% probability that the load will actually be below the forecast and there is a 50% probability that the load is above the forecast. A statement that it is a 50% probability forecast has no mening without adding some information to it. For example, is it a 50% Confidence Interval forecast in which case it would be two numbers with 50 percent probability that the actual number will be within the two numbers.
Response : 1. R2 has been revised such that the portion of the requirement that aimed at making information 'publicly available' was deleted – and the portion that focused on sharing information with reliability-related entities was moved into R7 of the revised standard. R7 of the revised standard has two parts – the first part requires that the Transmission Service Provider give data and information to its Transmission Operators (without needing a request) within 7 days of a modification			

Question #4			
Commenter	Yes	No	Comment
to CBM – the second part requires the Transmission Service Provider to share the same information with other reliability-related entities that request the information within 7 days of the request. With these changes, the confidentiality issue should not be a concern. All the requirements that indicated that an entity had to make data or information 'publicly available' have been removed from the standard. Public availability of information will be addressed by NAESB in business practices. This modification supports the intent of your suggestion. 2. R5 was merged into R3 in the revised standard except that the retention of this data is now addressed in the compliance section of the revised standard. The revised standard requires that all reserve margin requirements be documented – see R3.1.2 in the revised standard. This change supports the intent of your suggestion. 3. R6.2 - All of the resource adequacy requirements were removed from the standard as they will be addressed in greater detail in a new resource adequacy standard under development with a different SAR and drafting team. As revised, this standard assumes that the resource adequacy studies have taken place and the studies and study results must be made available as support for a request for CBM.			
		☑	1. MRO recommends that R2 be changed from "following a request by an entity with a valid need for such information" to "following a request by a Functional Entity with a valid need for such information, subject to security and confidentiality requirements." 2. R5.3 does not represent all the conditions that organizationally exist in the MRO, therefore, we recommend that a bullet be added under R5.3 as follows" "Planning Reserve Sharing Group reserve margin to meet the Regional Reliability Organization resource adequacy requirements". 3. R6.2 should refer to "a load forecast that has a 50/50% probability of occurrence". This means that there is a 50% probability that the load will actually be below the forecast and there is a 50% probability that the load is above the forecast. A statement that it is a 50% probability forecast has no mening without adding some information to it. For example, is it a 50% Confidence Interval forecast in which case it would be two numbers with 50 percent probability that the actual number will be within the two numbers.
Response: 1. R2 has been revised such that the portion of the requirement that aimed at making information 'publicly available' was deleted – and the portion that focused on sharing information with reliability-related entities was moved into R7 of the revised standard. R7 of the revised standard has two parts – the first part requires that the Transmission Service Provider give data and information to its Transmission Operators (without needing a request) within 7 days of a modification to CBM – the second part requires the Transmission Service Provider to share the same information with other reliability-related entities that request the information within 7 days of the request. With these changes, the confidentiality issue should not be a concern. All the requirements that indicated that an entity had to make data or information 'publicly available' have been removed from the standard. Public availability of information will be addressed by NAESB in business practices. This modification supports the intent of your suggestion. 2. R5 was merged into R3 in the revised standard except that the retention of this data is now addressed in the compliance section of the revised standard. The revised standard requires that all reserve margin requirements be documented – see R3.1.2 in the revised standard. This change supports the intent of your suggestion.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
3. R6.2 - All of the resource adequacy requirements were removed from the standard as they will be addressed in greater detail in a new resource adequacy standard under development with a different SAR and drafting team. As revised, this standard assumes that the resource adequacy studies have taken place and the studies and study results must be made available as support for a request for CBM.			
Southern Co Svcs		☑	5.2 comments: The wording in R5.2 of the proposed standard implies that only one of the identified entities has a role in determining the Load-Serving Entity's resource adequacy requirements. These adequacy requirement could be determined by one or more or none of the listed entities. This requirement should be reworded to require the LSE to list the responsible entity(ies). Suggested wording: R5.2. Identify the entity(ies) (e.g., the municipality, state commission, Regional Transmission Organization/Independent System Operator, Regional Reliability Organization, or Regional Entity) responsible for establishing the Load-Serving Entity's resource adequacy requirements. 5.3 comments: The Load-Serving entity should be added to the list in R5.3. 6.4 comments: The resources referenced in R6.4 should be limited to only those owned or controlled by the Load-Serving entity. Therefore, R6.4 should be reworded and R6.4.2. should be removed. Suggested wording: "R6.4. Identify all resources that are owned or controlled by the Load-Serving Entity in its area excluded from serving the Load-Serving Entity's load, including:" 6.5 & 6.7.1 comments: Replace rates with assumptions. 6.7.5 comments (grammatical): Change effect to affect.
Response: The data retention aspects of R5 were modified and moved to the compliance elements of the standard – the requirement to have the data and information has been absorbed into Requirement 3 in the revised standard. The revised standard includes the following language: "Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them. . ." in support of your suggestion relative to R5.2. R5.3 was assigned to the Load-Serving Entity, and required the Load-Serving Entity to retain documentation relative to the determination of CBM. The drafting team isn't sure how to incorporate the suggested modification. The drafting team removed the requirement (R6) that addressed probabilistic studies. This standard has been revised to assume that the studies have taken place.			
SERC ATCWG		☑	1. R8.1 needs clarification.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			2. As drafted, R5.2 implies that only one of the identified entities has a role in determining the Load-Serving Entity's resource adequacy requirements. This adequacy requirement could be determined by more than one or none of the listed entities. This requirement should be reworded to require the LSE to disclose the responsible entity(ies). 3. The resources referenced in R6.4 should be limited to only those owned or controlled by the Load-Serving entity. Therefore, R6.4 should be reworded to state, and R6.4.2. should be removed.
Response: 1. Based on stakeholder comments, R8.1 was removed from the standard. 2. The data retention aspects of R5 were modified and moved to the compliance elements of the standard – the requirement to have the data and information has been absorbed into Requirement 3 in the revised standard. The revised standard includes the following language: "Identification of all applicable reserve margin and resource adequacy requirements, and the entity(ies) responsible for establishing them. . ." in support of your suggestion relative to R5.2. 3. The drafting team removed the requirement (R6) that addressed probabilistic studies. This standard has been revised to assume that the studies have taken place.			
Entergy Services	☑		
FirstEnergy	☑		
ITC	☑		
PSC of SC	☑		

5. In the NERC glossary, CBM is defined as being necessary to meet "Generation Reliability Requirements." Do you believe the current NERC definition is adequate? If "No," please explain why in the comments area.

Summary Consideration: There was no consensus amongst those who responded to this question. Based on a review of all the detailed comments submitted, the Drafting Team believes that the current NERC definition of CBM is adequate.

Question #5			
Commenter	**Yes**	**No**	**Comment**
WECC MIC MIS ATC Task Force		☑	GRR is used as a defined term without a definition. If retained as a defined term it needs a definition. As to the definition of CBM, the Team suggests a more specific NERC CBM definition as follows: "Capacity Benefit Margin" CBM is the amount of firm import transmission capability, requested by the LSE, to exclusively serve identified load only during periods of emergency generation deficiencies extending beyond the beginning of the scheduling hour in which the emergency generation deficiency occurs." Commentary: The "located on" was excluded from the suggested language because the definition would have to generically identify the system of "that TSP" – which TSP is "that"? This is impractical when the definition is written from the standpoint of the LSE as opposed to the existing TSP paradigm. "…[T]o enable access by the LSE to generation from interconnected systems" was deleted as that is conveyed in the determinant "import" as suggested in the new definition. "Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements" was excluded from the suggested definition as it is merely commentary and adds nothing to the definition.
Response: GRR was not intended to be treated as a defined term, and it is not indicated as such in the actual definition. GRR does not completely define CBM. The revised MOD-004 does not use the acronym, 'GRR.'			
APPA		☑	The definition of CBM is causing the industry to calculate CBM is many different ways. The definition of CBM states that CBM is used to meet an entity's "generation reliability requirements." Some entities are saying that the use of CBM to handle "Planning Reserves" is the correct and reserve transmission capacity as CBM to bring in energy from energy resources outside the BA's area that were determined when the entity calculated "Planning Reserves." Other entities calculate the amount of CBM capacity based on "Operating Reserves." As the definition of CBM is written either one could be correct or incorrect. This definition worked well when the industry maintained reliability of the BES from Reliability Policies.

Question #5			
Commenter	**Yes**	**No**	**Comment**
			The CBM definition's undefined term "generation reliability requirement" allows an excessive amount of transmission capacity to be removed from the BES as CBM and prevents the correct amount of ATC to be placed on the market for use by other entities. In addition, the definition of CBM is so general it is impossible for a Compliance Program to determine if an entity is non-compliant.
Response: The intent of all of the new requirements is that the LSE must prove, to the compliance monitors (now called Compliance Enforcement Authority) satisfaction, that it is properly stating its need for transmission margin to meet its "resource adequacy" requirements. It is the full intent of the language used in the requirements to prevent the overstatement of CBM that you imply will happen. The compliance monitor will have significant responsibility to make this determination.			
IESO IRC SRC		☑	We should redefine it along the line that is provided in FERC's directive that CBM is required for generation deficiency only.
Response: See summary response,			
ERCOT		☑	See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.			
ITC		☑	The NERC glossary and CBM definition should be expanded to include other terms, such as "Resource Adequacy" to fully address this issue. This expansion may come as a result of future LSE requests for CBM based on a justification not currently envisioned.
Response: While we understand this desire, the definition is a high-level description of CBM; the requirements contain all the details, and therefore, we don't believe that the definition should be expanded to include all this detail.			
Nova Scotia Power		☑	CBM is required to meet Resource Adequacy Requirements. Generation Reliability implies that access to transmission makes generation (and generators) more reliable. Resource Adequacy ensures that firm load can be supplied to a level of reliability adopted by the RRO. The resources to meet those requirements include reserve margin provided by excess generation or interruptable load. If the "resource" is located across a posted path, then CBM provides access to the resource. Since "resource" can include generation and load, then the NERC definition is insufficient.
Response: See summary response.			
MEC MRO	☑	☑	It would be better if CBM is defined in the NERC glossary as provided in the FERC Order 890 as meeting "Generation Reliability Criteria" however, the existing definition is adequate.
Response: See summary response.			
FirstEnergy	☑		
SERC ATCWG	☑		
Duke Energy	☑		

Question #5			
Commenter	**Yes**	**No**	**Comment**
Entergy Services	☑		
MEAG	☑		
MEC Trading	☑		
PSC of SC	☑		
Southern Co Svcs	☑		

6. **In the future, LSEs will be required to request CBM. Do you believe there should be a queuing process to deal with potential conflicts between requests for CBM and transmission service requests? If "Yes" please describe how you believe the queuing process should work and whether the process should be addressed in this standard or elsewhere.**

Summary Consideration: There was no consensus amongst the stakeholders who responded to this question. In the absence of a clear consensus, a queuing process has not been incorporated in the revised draft of the standard. This shall serve as a single response to all opinions offered in response to this question.

Question #6			
Commenter	**Yes**	**No**	**Comment**
PSC of SC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Response: Note that stakeholders do not need to respond to every question on the comment form.			
APPA		☑	The needs to secure a transmission path to reach generation resources outside a LSE Balancing Authority Area that will "meet generation reliability requirements" are extremely important to reliable operations of the BES. Since the Reliability Standards are written to insure reliable operations a TSP would be hard pressed to deny an LSE the ability to secure resources to meet "generation reliability requirements." If a TSP denied this service it could be exposed to acts of non-compliance should the BES's integrity diminish because the TSP denied the LSE the CBM capacity.
Entergy Services		☑	There is no need to have a queue process for CBM. Transmission Service Requests are approved if ATC is available and ATC is calculated using CBM. Therefore, CBM needs to be set aside first to accurately calculate ATC before Transmission Service Requests can be approved.
FirstEnergy		☑	CBM is a reliability product that must be available when called upon. Transmission service requests are a business product that may have reliability impacts if properly scheduled. Any queing process would have to give priority to CBM.
IESO IRC SRC		☑	By virtue of the definition and formula of ATC determination, CBM is the component that must be allotted before any transmission service requests are assessed and granted.
ERCOT		☑	See IRC comments submitted by Charles Yeung.
ITC		☑	Absolutely not. The original justification for CBM is that the transmission system was built for the contingencies envisioned by CBM. It was paid for by the original local network customers. No one should be allowed, by queuing process, to supercede this. However, if there is not sufficient transmission capacity to provide a CBM margin as well as requests for transmission service, the system should be expanded to provide the needed capacity. While there is a system impact process to cover this situation, it has

Question #6			
Commenter	**Yes**	**No**	**Comment**
			not worked well in the last 10 years. Improved import capacity into a deficient system to meet all needs should be addressed in the planning process not some queuing process.
MEC MRO		☑	CBM is basic reliability requirement. If not met, transmission expansion planning should plan for it and should not sell addition transmission service on the same path/flowgate.
SERC ATCWG		☑	We need more clarification on the queing process. What is the definition.
WECC MIC MIS ATC Task Force	☑		The question is unclear at to whether it applied to an R4/R6 "request to set aside" or an R8 "request to schedule energy." A queuing should apply at the initial "request" stage (R4 and R6). Since by definition, CBM is a "firm" commitment, its request under R4/R6 would place it in the highest priority queue. If addressed there, no queuing problem exists in R8. Since the R8 "schedule" cannot take place until the RC declares an EE2 under R10; and whereas the R4/R6 set the priority, it would seem there would be no queuing issue even in emergency conditions. If this is not the case, the NERC Team should clarify how each of these "Rs" interplays sequentially. R4. In R4 CBM is "requested" to comply with a regulatory mandate. This would include a body such as a state or local governance board in which case the LSE is at the mercy of the regulatory body. R6. We read R6 as an alternative method for determining CBM "IF" the regulatory approach in R4 does not apply. (If that's not the case that should be clarified.) R5. Either way, in R5 the approach and the details get documented and retained. R7-R8. In R7 the TSP makes sure there is enough to go around in ***anticipation*** that the LSE can "schedule" it when needed under R8. If the request for queuing is under R4, the LSE's request should have the absolute highest priority; otherwise, it could be forced into immediate noncompliance with it regulatory mandate. Since the requested amount under R4 or R6 is set aside as firm before R8 is triggered (with the condition precedent under R10), then under R8 queuing should not be a problem as the capability requested in R4 was already set aside in R7. Thus, if the question addresses R4 – "request" to "set aside" – than "yes" there should be a queue and the LSE should be first. If the question addresses, R8 – "request" to "schedule" the question is actually moot as the capacity has already been set aside as firm by the TSP in R7 and queuing should simply be in accordance with the now applicable rules. Firm first… others next.
Response: Re your first comment: Assuming that all LSEs have submitted their request per section R4.2, there should be			

Question #6			
Commenter	**Yes**	**No**	**Comment**
no need for queuing as long as the appropriate CBM was set aside in the first place. Re: your 2nd comment: We believe all LSEs are "at the mercy" of those entities responsible for setting their resource adequacy requirements. I.e., you can't ask for more CBM then they would allow you to have via a CBM MW import requirement. If "there is not enough to go around," you need to go back to the responsible entities (the ones setting your rates) and request additional transmission to meet resource adequacy. If they don't agree, you don't have any justification. Re: your 3rd comment: The last comment implies there shouldn't be a queuing process. If the LSE's request for CBM is of the highest priority, there is no queuing, they come first. We agree the LSE should come first and get all they ask for.			
Duke Energy	☑		CBM requests should be addressed on a "first-come first-served" basis. LSE's are required to submit annual 10-year projections to the Transmission Service Provider. CBM requests will have lower priority than existing queued firm transmission service requests. NAESB should formalize the queuing process.
MEC Trading	☑		This should be address in the TSPs OATT and filed at FERC. (Maybe it could be a requirement to just that in this standard)
Response: FERC has already stated that transmission rates must be adjusted to account for those that use or don't use CBM.			
Nova Scotia Power	☑		There can easily be conflicts for multple LSE's requesting CBM, and there is a problem if the aggregate of all CBM requests exceeds the transmission capacity (R7). Therefore, if this is a new requirement, then there must be some "open season" to collect requests within a fixed time window similar to the Section 2.1 of FERC Order 888 pro-forma tariff. The CBM would be awarded to all comers if there is sufficient capacity but is allocated in lottery fashion if there are more requests than capacity. However, there is the question of the role of ETC in allocating CBM by this method. How much transmission capacity would be offered for CBM? I assume that existing Transmission Reservations cannot be impacted by the CBM bidding process, so only ATC for the planning horizon (if there is any) can be offered. What would an LSE pay for CBM. If it was required to pay the same as it would for a long-term (firm) reservation, then are they really getting CBM or are they getting a long-term firm Transmission Reservation). Some entities interpret Section 2.1 of Order 888 pro-forma tariff to permit bidding on amount and duration to award capacity to the "highest net present value" of the capacity. If there is no charge for CBM, how does the TSE recover lost transmission revenue? It seems that many of these questions must be directed to NAESB
Response: If the filed requests for CBM in section R4.2 exceed the transmission capacity available, it should be discovered at that point (re: your statement "aggregate of all CBM requests exceeds the transmission capacity"). It is important to note that R4 requests are based on recognized historic entities responsible for resource adequacy. If the system is not capable of handling these requirements (as would happen if there wasn't sufficient capacity to cover all "valid" CBM requests), then this entity should be consulted as to what to do. A queuing process will not result in someone meeting their resource adequacy			

Question #6			
Commenter	**Yes**	**No**	**Comment**
responsibility.			
Southern Co Svcs	☑		The request to reserve (set aside) a CBM amount by the LSE should be treated like any other firm transmission service request.
The STD disagrees. The LSE's request for CBM is of the highest priority, there is no queuing, and they come first.			

7. **Do you agree with R3.3 of MOD-004-1 that requires that CBM be algebraically subtracted from the path on which it was reserved, or should the CBM set aside be based on the response of the network by modeling the transaction from the POR to POD at the CBM import MW level? Please explain your answer in the comments area.**

Summary Consideration: There was no consensus amongst those who responded to this question to indicate support or rejection for the version of R3.3 in the first draft of the standard. Several commenters suggested that the impact of the generation import capability needs to be a consideration in CBM allocation and this was added to the revised requirements. Based on feedback in response to other questions in this comment form and feedback on other standards, the drafting team has also revised this section of the standard to make the determination of CBM a two-step process that aligns more closely with MOD-028, MOD-029, and MOD-030, while merging portions of R3 and R 7 into R4 of the revised standard. In the first step of the process the Transmission Service Provider analyzes how much of each request's CBM can be allocated, and in the second step the Transmission Service Provider sets CBM for a specific Posted Path or Flowgate. Here is the relevant revised portion of the standard – (note that in the revised standard the Load-Serving Entity that wants CBM must provide significant documentation to support the CBM request):

R4.1. Determine the amount of CBM (for use in R3.2) for each request by using one of the following:

- R4.1.1. For the Area Interchange Methodology and the Rated System Path Methodology, using the requested Generation Capability Import Requirement for the Posted Path
- R4.1.2. For the Flowgate Methodology, determining the significant impacts of each request on each Flowgate
  - 4.1.2.1. Determine impacts of a request by multiplying the requested GCIR by the Distribution Factor for the transfer of that import from the specified Balancing Authority relative to the Flowgate.
  - 4.1.2.2. Classify each impacts based on a Distribution Factor of 3% or greater as a significant impact.

R4.2. Set CBM for each Posted Path or Flowgate based on the sum of all requests such that all requests can be met simultaneously or all firm Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) has been allocated to CBM as follows:

- R4.2.1. For Posted Paths, set the CBM for each Posted Path equal to the lesser of:
  - The sum of all requests for Generation Capability Import Requirement for that Posted Path, minus the transfer capability set aside for reserve sharing for that Posted Path or
  - The firm ATC for that Posted Path
- R4.2.2. For Flowgates, set the CBM for each Flowgate equal to the lesser of:
  - The sum of the significant impacts of all requests for GCIR for that Flowgate minus the impact of transfer capability set aside for reserve sharing for that Flowgate, or
  - The firm AFC for that Flowgate

Question #7			
Commenter	**Yes**	**No**	**Comment**
PSC of SC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Response: Note that stakeholders do not need to respond to every question on the comment form.			
MEC Trading			(Not sure if the Yes/No is for the first part of thequestion or the second) Network Response on path should be based upon network response by modeling it from the POR to the POD.
Response: Please see the revised standard.			
IESO			The way it is specified in R3.3 (and R3.2) is the correct approach.
Response: Please see the summary consideration. The drafting team made significant modifications to this requirement in support of stakeholder comments.			
APPA		☑	The use of CBM capacity is just a reservation of transmission capacity that will only be used should an adverse situation develop in the BES and generation resources are needed to meet "generation reliability requirements." However, those generation resources are out side the LSE's Balancing Authority's Area. The simulation of energy over the CBM would be a study to determine how the system reacted under adverse operating conditions of the BES. How the use of CBM transmission capacity is treated will be determined how the final definition of CBM is written. Presently, both method would be needed because CBM is used for different purposes throughout the industry.
Response: In general, we agree with your observations. However, CBM should not be used for "different purposes." The intent of this standard is to specify what purposes CBM may be used for.			
Duke Energy		☑	The standard should be flexible enough to allow the Transmission Service Provider to use either method which best supports reliability in their control area.
Response: Agree. The standard was revised to align more closely with the modifications made to MOD-028, MOD-029 and MOD-030.			
Entergy Services		☑	CBM should be set aside on a path based on the response of CBM import MW level on that path. This should be treated similar to impact of loads or generation on paths by including their response on paths rather than algebraically subtracting from the path..
Response: As revised, the standard requires consideration of the generation import capability in support of your suggestion.			
IRCSRC		☑	CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity..
Response: As revised, the standard requires consideration of the generation import capability before 'capping' the amount of CBM that can be allocated.			

Question #7			
Commenter	**Yes**	**No**	**Comment**
ERCOT	☑		See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.			
ITC		☑	It should be based on the response of the network to the most likely sources. It is important that the availability of generation in the source area be considered when doing this. For example, assuming a source network with minimal reserves would be a poor assumption. This is an area that will ultimately require a very astute compliance monitor to determine compliance.
Response: This is not a NERC issue, but really a FERC or Market Monitor issue. From the NERC perspective, the TSP should base their analysis on the request made by the LSE.			
MEC MRO		☑	CBM on path/flowgate should be the 'max' rather than 'sum' of all that's required to meet each individual LSE's resource adequacy requirement. Reasoning: Generation emergencies don't happen all at once. Reserve a 'sum' is beyond the 1-day-in-10-year criterion (or whatever criterion that's used by the region), and is not an efficient way of utilizing transmission capacity.
Response: See response to IRC SRC above.			
Nova Scotia Power	☑	☑	It will depend on where the LSE is located in relation to the interface. For example, can an LSE request CBM to access reserve capacity two systems away? Let's say that there are there radially connected systems A is connected to B and C is is only connected to B. LSE#1 in A requests CBM through B to access capacity in C. LSE#2 requests access to capacity in A. In assigning import CBM on the A-B interface, LSE B must consider that the requirement for capacity reserve is due to a shortage in B or in C or to a lesser probability in B+C.
Response: It is the responsibility of the TSP to define in its procedure for requesting CBM any limitations on the Balancing Authorities from which generation supporting the GCIR may be supplied.			
FirstEnergy	☑		The posted ATC for the CBM reserved path should have been based on the network response or contractual limit for that POR to POD, and thus subtracting CBM on that path is consistent with the ATC determination.
Response: See summary response.			
MEAG	☑		The use of CBM capacity is for LSE under any potential emergency of generation deficiency. By modeling the CBM as the transaction from the POR to POD at the required CBM import MW level would treat the adverse operation as a normal condition and reduce the import TTC for the TSP.
Response: See summary response.			
Southern Co Svcs	☑		For this method, a maximum TTC is calculated for each path, and the CBM set aside is decremented from that path to yield the remaining capacity available for Firm use. The network response for the CBM set aside (POR to POD) is considered and reflected in the TTC when it is calculated. To consider the network response of the CBM set aside for a second time would result in a lower value than the requested amount being decremented from the requested path. This could result in an over-

Question #7			
Commenter	**Yes**	**No**	**Comment**
			commitment for that path.
Response: See summary response.			

8. If the needs for capacity that resulted in a request for CBM have been met by other means (e.g., via capacity-backed transmission service or new generation), should this standard require that CBM be re-evaluated and possibly reduced (resulting in a change in ATC)? Please explain your answer in the comments area.

Summary Consideration: Most stakeholders who responded to this question indicated that the standard should require that CBM be re-evaluated and possibly reduced, resulting in a change in ATC. The standard has been changed to incorporate the following sub-requirement for a monthly re-evaluation by the LSE of its request to reflect any changes in future CBM needs.

R3.2 At least every thirty-one days, update the request provided per R3.1 to reflect any changes that alter future needs for CBM or indicate that no change is needed.

Question #8			
Commenter	**Yes**	**No**	**Comment**
PSC of SC			Our comments are from a regulatory perspective. This is strictly a technical issue.
Response: Note that stakeholders do not need to respond to every question on the comment form.			
Southern Co Svcs		☑	This could facilitate the opportunity for hording transmission capacity. The standard as drafted requires the LSE to request CBM as needed and maintain the proper documentation as required.
Response: It can't be hoarding if the CBM is reduced. Currently, many TSPs set aside CBM but fail to reduce it when LSE's make additional firm purchases, thus reducing their LOLE when CBM is not reduced. It is also conceivable that an LSE may not renew a purchase thus increasing their LOLE. In that instance, the CBM should be increased. A new requirement to that the LSE adjust CBM when their Generation Capability Import Requirement needs change would prevent hoarding.			
WECC MIC MIS ATC Task Force	☑		CBM should be called on only after TRM has been utilized during 0-59 minutes. Rolling into 60+ minutes, CBM should be called on. That said, as the foundational emergency subsides there should be a statement in the standard to "unwind" the utilization of CBM. If, for example, an LSE had reserved 100 MW of CBM in accordance with R4 but when required to use that capacity under R8 could actually serve 60 MW by other means, then CBM should be reduced to 40 MW and ATC increased accordingly.
Response: This question was intended not to cover decrementing of CBM when scheduled, but decrementing of CBM when assumptions change regarding how much is needed. We don't believe the Firm ATC will change, as the "reserved" capacity for CBM will simply turn into "scheduled" energy flow. The Non-Firm ATC would decrease, as the CBM that could be sold as non-firm would decrease.			
APPA	☑		Reducing the CBM because new generation is built in the LSE's Balancing Authority's Area would be a financial decision by the LSE. I do not believe this Standard has authority to mandate financial decisions. However if new reliability rules are passed that limit the amount of resources located outside the LSE's Balancing Authority's Area, which

Question #8			
Commenter	**Yes**	**No**	**Comment**
			can be used to meet "generation reliability requirements" then this Standard has the obligation to lower the CBM to the predetermined about of transmission capacity used for CBM.
Response: You're correct in that this standard cannot mandate financial decisions. However, when new generation is built or external resources are purchased, it is the decision by the LSE to meet its resource adequacy requirements in a more stable way than dependence on CBM. At the same time, when an LSE does this, it no longer is entitled to the full CBM prior to this change in resource adequacy.			
Duke Energy	☑		As resource mix changes, CBM would be re-evaluated on an annual basis with updated LSE requests for CBM.
Response: We agree that the resource adequacy requirements supporting CBM should be reevaluated every year. However this question is referring to resource decisions made between resource adequacy calculations.			
Entergy Services	☑		CBM should be recalculated to determine accurate CBM requirements that should include meeting the generation requirement from any other transmission service or new generation. Any double counting of elements that impact CBM calculations should be avoided.
Response: Most stakeholders who responded to this question indicated agreement.			
FirstEnergy	☑		In the case of new generation, the recalcuation periodicity would conceivably be infrequent. In the case of capacity-backed transmission service, the recalculation periodicity may be frequent, but is necessary to allow the markets to function properly.
Response: Most stakeholders who responded to this question indicated agreement.			
IESO	☑		CBM is intended for having transmission capability to meet generation deficiency. If this deficiency can be met via other means, then the CBM allotted will no longer be required and could even be reduced to 0 if required.
Response: Most stakeholders who responded to this question indicated agreement.			
IRC SRC	☑		CBM is intended for having transmission capability to meet generation deficiency. If this deficiency can be met via other means, then the CBM allotted will no longer be required.
Response: Most stakeholders who responded to this question indicated agreement.			
ERCOT	☑		See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.			
ITC	☑		This is a simple answer. You invite double counting if you don't reduce CBM when this happens. It amounts to hoarding. This is already a problem in our opinion.
Response: Most stakeholders who responded to this question indicated agreement.			
MEC Trading	☑		It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means. Maybe the TSPs OATT should be the right place for this information.

Question #8			
Commenter	**Yes**	**No**	**Comment**
Response: The SDT agrees with your point one. However, the OATT doesn't need to be changed if the standard we're writing requires CBM to be adjusted when additional resources are acquired which reduce dependence on CBM.			
MEC MRO	☑		It is to the benefits of all stakeholders if the use of transmission is optimized so CBM should be re-evaluated and possible reduced if CBM is met by other means.
Response: We agree, and will have modified the standard to incorporate reviews and updates to CBM at appropriate time intervals.			
Nova Scotia Power	☑		CBM requirements can change from year to year. For example, if the market responds to price signals and additional generation is built, there is no longer a need for the originally plannned CBM, which should be released to the market. The same is true for entities which are required to install renewable generation or demand-side management programs, which can free existing generation to provide Resource Adequacy without the need for CBM
Response: We agree that the resource adequacy requirements supporting CBM should be reevaluated at least every year. However this question is referring to resource decisions made between resource adequacy calculations.			
MEAG	☑		

9. Do you think that Requirement R6 is appropriate for this standard? If "No," please explain why in the comments area.

Summary Consideration: R6 has been removed from the revised standard. There was no consensus amongst those who commented to support the retention of the ~~standard~~ requirement – the standard was revised assuming that the resource adequacy studies have taken place – the results of these studies must be documented to support the Generation Import Capability Requirement, but 'how' to conduct these studies is not addressed in the revised standard. This shall serve as a single response to all opinions offered. Note that there is another SAR under development to address resource adequacy assessments.

Question #9			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The LSE is performing many functions of the other Functional Entities, which are described in the Functional Model. As stated in Question 3 the author has incorrectly assigned duties of many different Functional Entities to the LSE in R.6 and will create confusion between this Standard and other Standards that are written for the many different subjects covered in R.6. It is recommended this requirement be completely removed.
Entergy Services		☑	Requirement R6 addresses resource adequacy requirement and it does not belong in the CBM standard. Requirement R5.2 covers identification of appropriate criteria used for resource adequacy studies that will identify need for CBM, if any. Probabilistic studies, if included in resource adequacy studies criteria shall be used and there is no need to include requirement R6 in this standard.
WECC MIC MIS ATC Task Force	☑		As drafted, the standard appears to say there are two ways to establish the level of CBM required: 1) via regulatory mandate at R4 or 2) via probabilistic analysis at R6, assuming there is no regulatory mandate. If that is not the intent of the two methods, than perhaps the more clarity on when the two methods would be used is in order.
IESO IRC SRC	☑	☑	By and large, R6 describe the process and assumption requirements for resource adequacy assessment via which the CBM is determined. It is our interpretation that FERC requires the basis of this assessment be made known to support and demonstrate a fair and consistent approach is taken in determining the CBM value. That said, R6 could arguably be placed in a standard on resource adequacy assessment. If R6 is to stay, at the very least some of the subrequirements can be removed or combined (see Comments under Q2 for an example).
ERCOT	☑	☑	See IRC comments submitted by Charles Yeung.
ITC	☑	☑	How else would a compliance monitor be able to evaluate a justification for CBM if he

Question #9			
Commenter	**Yes**	**No**	**Comment**
			doesn't have the input used to make such a determination. If anything, this could be expanded to assist the compliance monitor in such a determination.
MEC	☑	☑	I prefer if all CBM requests were supported by appropriate probabilistic based studies. It does seem odd that when the better approach (the probabilistic approach) is used, then the standard has all kinds of requirements defining how the better approach is to be done.
MRO	☑	☑	The MRO would prefer if all CBM requests were supported by appropriate probabilistic based studies. It does seem odd that when the better approach (the probabilistic approach) is used, then the standard has all kinds of requirements defining how the better approach is to be done.
Nova Scotia Power	☑		There should be a high level of proof that CBM is required. An important component is the ability to deliver this energy with single contingencies.
Duke Energy	☑		
FirstEnergy	☑		
MEC Trading	☑		
PSC of SC	☑		

10. 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: Some entities may desire to pursue regional differences based on their current practice or tariff. We agree there may be commercially sensitive information in the CBM process, and have removed all public posting requirements from this standard and have requested that NAESB address the requirements related to "public posting." We have modified the timings in the standard to allow for processing of requests in a reasonable amount of time.

Question #10			
Commenter	**Yes**	**No**	**Comment**
APPA	☑		As noted above.
Response: Please see response above.			
ERCOT	☑		ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area Interconnection and there has been no reservation of transmission capacity in ERCOT. Capacity Benefit Margin is defined as the amount of firm transmission transfer capability preserved by the transmission provider for Load- Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies. 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. In the

Question #10			
Commenter	**Yes**	**No**	**Comment**
			current and future ERCOT market design the use of CBM is not applicable to the ERCOT Interconnection. ERCOT does not have a synchronous connection with any other Control 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 SDT agrees this is a concern - ERCOT may wish to pursue a request for a Regional Difference..			
MEC Trading	☑		FERC Order 890 required consistency and this standard does not require any consistency.
Response: The consistency is achieved by requiring an LSE to prove that they have supportable resource adequacy requirements that allow for the use of CBM. By law, the ERO cannot set resource adequacy standards but can require an LSE to demonstrate that they have supportable requirements that do provide for CBM to meet these requirements. We expect consistency within the domain of the local entity responsible for resource adequacy (by state, by region, etc).			
Nova Scotia Power	☑		R2 requires documentation to be "publicly released" (published on OASIS) information that is either commercially sensitive or can include Critical Infrastructure Information, the wording of R8 in MOD-008 should be used in MOD-004 to protect information. The process of taking bids on CBM will require modifications to transmission Tariffs and Market Rules may have to be updated to reflect the new requirements.
Response: We have changed R2 so that it no longer includes the phrase, 'make publicly available,' and expect that NAESB will address release of information to customers. Note that in the revised standard, the Transmission Service Provider must share the models it uses to allocate CBM with various reliability entities in R7 of the revised standard. We don't expect tariff changes for CBM. See responses to question 6 regarding queuing.			
Southern Co Svcs	☑		R7 requires the Transmission Service Provider to answer a request for CBM within 30 days of receipt. This is inconsistent with the time allowed to answer other firm transmission service requests per Tariff and should be revised to track the tariff requirements for processing long term firm transmission requests.
Response: The revised draft of the standard requires the TSP to respond in 14 days to requests for monthly values in the current and subsequent year, because the LSE is required to update the request every 31 days. (See R3 in the revised standard.) The time for response to requests for yearly values beyond that time period has been extended to 60 days. (See R4 in the revised standard.)			
ITC		☑	R4 gives the LSE great latitude in defining their resource adequacy requirements. R4 allows the LSE to fully document whatever requirement they have. It will ultimately be

Question #10			
Commenter	**Yes**	**No**	**Comment**
			up to the compliance monitor to evaluated their justification and documentation.
Response: The SDT agrees with this comment.			
IESO IRC SRC		☑	However, there are entities that do not provide physical transmission services. Hence, these standards or some of the requirements in these standards may not apply.
Response: FERC has indicated that the TSP must offer CBM to its LSEs, and as such, the standard requires all TSPs to prepare and maintain CBM procedures. Requirement 1 applies regardless of whether or not you provide physical transmission service, but allows for the TSP to specify the details of how they have elected to implement CBM. All other requirements are dependent upon a requested need for or use of CBM, and may not apply if CBM is not used in the region.			
WECC MIC MIS ATC Task Force		☑	
Duke Energy		☑	
Entergy Services		☑	
FirstEnergy		☑	
MEC		☑	
MRO		☑	
PSC of SC		☑	

11. **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-001-1. Comments:**

Summary Consideration: Several commenters provided suggestions for improvement, which have been incorporated into the new standard. The drafting team notes that this question incorrectly referred to MOD-001, and apologizes for any confusion this may have caused. Please see the cover page of this report for a complete list of requirements modified in response to stakeholder comments.

Question #11	
Commenter	**Comment**
WECC MIC MIS ATC Task Force	**A.** R3. Each of the sub-bullets contains the term "reserve sharing" (R.3.1.2; R.3.2.1; R.3.3.1). This is not used as a defined term in the standards; however, Reserve Sharing Groups is a NERC defined term and may more accurately address what the standard is seeking to address. Suggested rewrite: (E.g.) R3.2. The Transmission Service Provider that uses the Rated System Path… R3.2.1. The Transmission Service provider shall not include in the CBM calculation any transmission capacity set aside as part of a Reserve Sharing Group agreement already accounted for in the TRM calculation. **B.** R4. We suggest the second parenthetical phrase be deleted as it does not add any significant clarification. **C.** R6.3.1. Designated Network Resource (DNR) is used as a defined term without a NERC Glossary definition. The Team suggests using language from Section 1.26 "Network Resource" within the Pro Forma OATT as a springboard for a new definition. **D.** R6.4. - Intent is unclear. R6.4 Suggested rewrite: "Identify all resources in the Load-Serving Entity's ***Balancing Authority Area*** excluded from serving the Load-Serving Entity's load, including: " (Emphasis and language added) **E.** R8 is unclear. If CBM is "reduced" in R7.2 what does it mean that the LSE is "still entitled to the CBM MW import?" Please clarify or rewrite.
Response: A. R3 - Re: Reserve sharing – the term 'reserve sharing' is not defined and has a meaning that is well understood so the team did not define the term. Drafting teams have been asked to avoid defining terms that have a commonly understood meaning. B. R4 – Re elimination of second parenthetical – the drafting team adopted this suggestion and revised the entire requirement so it is simpler to read. **C.** The term "Designated Network Resource" has been removed. D. Requirement 6 was deleted from the revised standard. The revised standard assumes that the studies have been completed and requires that there be documentation to support the studies, but the revised standard does not detail 'how' to perform the studies. E. R8 was confusing and has been deleted. The revised standard includes much clearer requirements for the allocation of CBM and requires	

Question #11	
Commenter	**Comment**
that the Load-Serving Entity update its request for CBM at least once/31 days.	
WECC MIC MIS ATC Task Force	**F.** Order 890, P. 262 states: "…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…process." (Emphasis added.) "We direct public utilities…to specify the generation deficiency conditions during which an LSE will be allowed to use…CBM." (Emphasis added.) R10. states, "The Load-Serving Entity shall declare a NERC Energy Emergency Alert (EEA) 2 and initiate all steps in EEA 2 prior to scheduling of energy over transmission capacity set aside as CBM." (Emphasis added.) EOP-002, states: "A. General Requirements **1.** Initiation by Reliability Coordinator. An Energy Emergency Alert may be initiated *only by a Reliability Coordinator* at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity." (Emphasis added.) In contravention to Order 890, P. 262, R10 as drafted *does not state the specific "generation deficiency conditions" required as a condition precedent for an LSE to call upon CBM*. In contravention to EOP-002, R10 grants an LSE the right to declare a NERC Energy Emergency 2. The NERC Drafting Team needs to remedy the conflict. Suggested language: *(Plagiarized from Attachment 1-EOP-002-0; Energy Emergency Alerts)* RX.1. Each Load-Serving Entity that is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or that cannot schedule known resources due to insufficient transmission capacity, shall instruct its Reliability Coordinator to declare an Energy Emergency 2. RX.2. Each Load-Serving Entity shall instruct its Reliability Coordinator to declare a NERC Energy Emergency 2 prior to scheduling any energy on transmission capacity reserved for CBM. R.X3. Each Reliability Coordinator instructed by a Load-Serving Entity to declare a NERC Energy Emergency 2 pursuant to this Standard, shall: • Initiate a NERC Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." • Act to mitigate the emergency condition, including a request for emergency assistance if • Required
Response: The drafting team revised the language in R10 rather than propose modifications to EOP-002. As revised, R10 requires the Transmission Service Provider to only approve Interchange Transaction Tags using CBM if the deficient entity is under an EEA	

Question #11	
Commenter	**Comment**
2 and CBM is available. This supports your suggestion to clarify that it is not the Load-serving entity that declares the EEA.	
WECC MIC MIS ATC Task Force	**G.** R11. The report required in R11 should also be mandated for delivery to the Balancing Authority and the Reliability Coordinator for purposes of post mortem examination. R11. Change "declared" to "instructed." **H**. R1.1. Should be changed to read: "Its procedure for a Load-Serving Entity to request its CBM import MW requirement on each REQUESTED Point of Receipt – Point of Delivery (POR-POD) combination or POSTED PATH…." (Emphasis Added.) Orders 889/890 do not require posting of information on every possible combination of POR/POD nor on every possible path. Thus information must only be posted on "Posted Paths." The defined term "Posted Path" must be added to the NERC Glossary to meet the intent of Orders 889 and 890 without creating an onerous burden to post information need by no one. It was not FERC's intent to require the posting of ATC / TTC et al for paths upon which there is no request for service. The following Posted Path definition must be added to the NERC Glossary and utilized in each of the ATC related standards: 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. Although the WECC Team has only addressed the definition of a Posted Path, we would encourage the NERC ATC to develop a parallel definition to properly delimit the Flowgates upon which information must be posted, as clearly, FERC did not intend that information be posted on each and every Flowgate or path simply because a Flowgate or path exists. FERC's intent as to what paths and Flowgates were affected by posting was clearly laid out in Order 889 as well as 890 per the aforementioned references.
Response: The requirement has been removed. The post mortem examination is the responsibility of the compliance monitor and if needed can be added to the standard as a type of 'exception reporting'.	
WECC MIC MIS ATC Task Force	**I.** R1.2 Should read, "…over each POSTED PATH or Flowgate." **J.** R1.4 Should read, "…for each timeframe by Flowgate or POSTED PATH, as applicable." (Emphasis Added.) **K.** R2. Should read, "…over each POSTED PATH or Flowgate…" **L.** R3.2 Should read, "…for determining Total Transfer Capability shall use the algebraic sum of all valid CBM requests for each POSTED PATH as the CBM for that path." (Emphasis Added.) **M.** R4.2. Should read, "…for each POSTED PATH or specified POR-POD combination for each year…" Again, a parallel definition to POSTED PATH for affected Flowgates would be of value here. This Team did not pursue

<table>
<tr><th colspan="2">Question #11</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>such a definition but encourages the NERC ATC Drafting Team to do so.
N. R5.1 Same comment as above at R4.2.
O. R6. Same comment as above at R4.2.
P. R7. And R7.2. Same comment as above at R4.2.
Q. R7.3 uses the term Import Entitlement without supplying a definition.
R. R8.1 Same comment as above at R4.2.
S. R13. Same comment as above at R4.2.
T. The WECC Team suggests the following clarifying language bee added to R8.

“R8. The Load-Serving Entity may request the scheduling of energy <u>*FOR ANY TIME HORIZON*</u> over transmission capacity set aside as CBM up to an amount equal to that determined under R7 as required by the Transmission Service Provider’s procedure pursuant to R1.3. (Emphasis added.)

R1 and R2 of MOD-004-1 should be clarified to show that CBM procedures and copies of the models used for allocating CBM over paths need only be made public “if” CBM is included in the TSP’s overall ATC calculation.</td></tr>
<tr><td colspan="2">**Response:**
I through P, R, S**.** We have incorporated the suggestion to define and use the term, ‘Posted Path’ in any of the identified requirements that were not retired or otherwise rephrased so they no longer need the term.
Q – R7 has been absorbed in R4 in the revised standard. The revised standard does not use the term, ‘Import Entitlement’ so no definition was added.
T – Allowing a Load-Serving Entity to schedule energy <u>*FOR ANY TIME HORIZON*</u> over transmission capacity set aside as CBM up to an amount equal to that determined under R7 as required by the Transmission Service Provider’s procedure pursuant to R1.3 does not support the definition of CBM which indicates that CBM is only to be used for emergency generation deficiencies. CBM should only be “scheduled” when it’s needed during an EEA2 event. For any time horizon beyond EEA2 events, a transmission reservation would be required.
U - All public posting requirements will be addressed by NAESB, however, FERC has indicated that the TSP must offer CBM to its LSEs, and as such, the standard requires all TSPs to prepare and maintain CBM procedures</td></tr>
<tr><td>BPA</td><td>R1. through R9. and R13. should be clarified that CBM need only be posted and requested on Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.</td></tr>
<tr><td colspan="2">**Response:** We agree. The entire set of standards was modified to adopt the use of the term, “Posted Path” as suggested by BPA and several other entities.</td></tr>
<tr><td>Duke Energy</td><td>R3.1.1 - Existing Transmission Commitments (ETC) is not included in definitions, but it should be defined.</td></tr>
<tr><td colspan="2">**Response:** We agree, and have written a definition for the Glossary in MOD-001.</td></tr>
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Question #11	
Commenter	**Comment**
Entergy Services	Entergy does not understand asking for comments on standard MOD-001-1 in this questionaire. Requirement R8.1 should include a condition by appending the language " if other entities who reserved CBM on that path are not using their share of CBM. Under no circumstances, the total use of CBM by all entities on a path at any time will exceed the total amount of CBM reserved on that path and for that period." Definitions of terms on page 2 do not belong in this standard and should be removed. Entergy does not use CBM in their ATC/AFC calculations. It appears from the standard that it is mandatory for Transmission Service Providers to use CBM. It should be left to the descretion of Tansmission Service Provider to use CBM and its use should not be made mandatory.
Response: Regarding MOD-001, this was a typographical error. The standard was revised and has a new requirement (R10) that clarifies that the Transmission Service Provider can only approve Interchange Transaction Tags using CBM if the deficient entity is under an EEA 2 and CBM is available. This supports your suggestion for modifying R8.1. The drafting team is allowed to submit definitions on any of the standards it submits. Since they all end up in the glossary, it is unimportant which standard to which they are attached. However, to aid in clarity, we will submit these definitions as part of MOD-001 the next time we make a posting. Regarding the TSP electing to not offer CBM, we believe that FERC is requiring this in Order 693, paragraph 1082: (1) clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards.	
FIrstEnergy	1. R2 requires copies of models used for CBM allocation, but the allocations are not required to be and may not be based on power flow modeling. In addition, it requires a request from an entity with a valid need. Methods are needed to determine what constitutes a valid need, who decides the validity of the need, and for resolving disputes. 2. R4.2 requires the LSE to allocate the CBM by path; however, the LSE may not have/use power flow tools consequently they may have difficulty complying with this requirement. The standard should include a method for managing offsetting resource requirements where the TSP has multiple

Question #11	
Commenter	**Comment**
	LSEs such as the situation where LSE A provides needed energy to LSE B without requiring an import. Under this scenario too much CBM may be set aside as the standard is currently written. R7.1 appears to attempt to cover this situation but it is not clearly stated and the basis for managing this is not addressed. 3. R13 states the TP "shall include all valid requests and projected CBM import MW requirements ... in its planning process." However, a method for needs to be established for managing situations where the import limitation is outside his area of responsibility. Overall, there are many good things in here. 4. R12 requires the TSP to make publicly available the report prepared by the LSE pursuant to R11. This requirement should be placed on the LSE that created and owns the report and has the retention responsibility. 5. To reduce confusion R14 should list the components of uncertainty rather than refering to MOD-008-1 R1.1. This MOD-008-1 requirment requires TPs and TOPs to include these elements in the TRM analysis where MOD-004-1 requires the LSE to exclude these values from the CBM calculation. The difference in application may be lost in switching back and forth between the two standard's requirements.

Response:

1. The standard drafting team modified the requirement as follows to eliminate the need to make the model publicly available and to allow for information other than models to be provided.

> The Transmission Service Provider and Transmission Planner shall each provide copies of the supporting data, including any models, used for allocating CBM over each Posted Path or Flowgate to the following:
>
> > Each of its associated Transmission Operators within seven calendar days of a modification to the CBM.

2. The standard is placing a responsibility on the LSE to document and provide data to support the justification of CBM. Beyond the LSE, it is expected that TSPs will have to upgrade their methods and systems in order to comply with this standard. This standard does place new obligations on several entities that may require time, money and manpower to comply.

3. CBM is only set aside on the facilities of the TSP in which the load is located. Accordingly, the TSP may not address import limitations outside their area of responsibility, consistent with their other planning processes.

4. We have eliminated this requirement and have requested that it NAESB address this and all other public posting requirements as business practices.

5. We intended to reduce confusion by referring the list in only one place, rather than create a potential for the lists to get

Question #11	
Commenter	**Comment**
out of synchronization as standards change. R14 was removed and the standard for TRM (MOD-008) includes a requirement to ensure that the same components of uncertainty are not used for both CBM and TRM. (See R2 in the revised MOD-008.) removed	
IESO IRC SRC	ETC is introduced in this standard for the first time and hence this term needs to be defined here.
Response: We have written a definition for ETC, and have included it with the revised draft of MOD-001.	
ERCOT	See IRC comments submitted by Charles Yeung.
Response: See response to IRC comments.	
ITC	(note question 11 should have referred to MOD-004 not MOD-001) While compliance has not been addressed, it is worth noting that the compliance monitor for CBM requirements will have to be a very astute individual or group to deal with the multiple possible resource adequacy requirements under the ERO. They will no doubt have to deal with non-jurisdictional entities to make their evaluations. We suspect it will be a lengthy process in some cases. We would also like to point out that the TSP has little latitude in using the MW import requirement supplied by the LSE. If they suspect that this value is too high, they don't have recourse here to do anything about it. Even if a large fine could result from a compliance issue, the TSP must sell service with a margin they may have good reason to feel is unjustified. Is a large fine justification enough to not give the TSP some latitute?
Response: There was a typographical error in the question and it should have referenced MOD-004 rather than MOD-001. We recognize that compliance may be challenging. The drafting team modified the standard so that the requirements that focused on conducting resource adequacy studies have been removed – the revised standard is written assuming that the studies have been conducted – and the revised standard requires that the results of the studies be documented.	
MEC Trading	The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards. We recommend that the purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation." The standard should make it clear that an LSE should be required to do comply with certain requirements within this standard only if it requests CBM. Also this industry is sophisticated enough to perform or have performed a probabilistic study so that it what the CBM should be based on.
Response: We revised the purpose in support of your suggestion. The standard drafting team has attempted to address the second comment in the requirements by limiting the scope of the requirement. The revised standard's R3 states, 'A LSE with that wants transfer capability set aside in the form of CBM shall:" The standard was revised so that the requirement for probabilistic studies (R6) has been removed – the revised standard's requirements are written assuming that these studies have been conducted, and the revised standard requires that the results of the studies be documented	
MEC	The purpose of each of the standards should be revised to be more in-line with the other ATC/TTC/TRM stanadards.

Question #11	
Commenter	**Comment**
MRO	The purpose in this standard be revised to state: "To promote the consistent and transparent…use of Capacity Benefit Margin (CBM) for reliable system operation."
Response: We revised the purpose in support of your suggestion.	
Manitoba Hydro	MH is not a supporter of the use of CBM as we believe that CBM makes the unsupportable assumption that there will be energy and transmission avaialable in the adjoining entitity during the time of the emergency. However as there a desire to maintain this feature, MH believes that there should be a requirement to build if CBM causes the AFC on a flowgate to become negative and that a portion of cost should be assigned to the LSE who is responsible for the CBM.
Response: The CBM needs to be considered in the annual evaluation of network service that TOs are supposed to make. If the transmission system in question cannot support the requested CBM, then a system impact study should commence. i.e., if you use CBM, then you should plan for it. NERC does not have the authority to require entities to 'build' transmission or generation facilities.	
Nova Scotia Power	The standard does not address the issue of export transmission capacity, since CBM is an import capacity only. An interface involves at least two TSP's: the TSP owning the export side and the TDP owning the import side. Has the drafting team examined the issues around a LSE that requests CBM held back from import but the export TDP can accept reservations without consideration to CBM. Say that the ATC on A-B interface is 200 MW. An LSE in B requires 50 MW of CBM which reduces import ATC on the B side to 150 MW and ATC on the A side remains at 200 MW. A transmission customer in B requests firm reservations on the A-B interface of 200 MW. The A TSP assigns 200 MW to the customer and the B TSP says he can only have 150 MW. The customer takes all 200 MW on the A side but nothing on the B side. Does he then effectively block A-B transactions?.
Response: This is an important point that is not being addressed. The assumption is that interconnections with neighbors are shared and were constructed, in most cases, to insure access to external resources to meet resource adequacy requirements. This was a mutual benefit. Both sides have access to external resources. An import problem to one is an export problem to the other. If one side has had "historical" access to external resources to meet their resource adequacy requirements, can the other side now complain that it impedes their "export" capability? This may be debatable but CBM has been a recognized margin for at least the 11 years since US deregulation. That's why it's important that any CBM claim be both documentable and supportable by whoever is responsible for the resource adequacy requirements of the LSE.	

12. In addition to the questions above, the standard drafting team is seeking industry input on a few issues discussed during the revisions of MOD-004 thru MOD-007 related to Capacity Benefit Margin. The intent of this portion of the comment form is to solicit general feedback from the industry related to CBM. Please take a few minutes to offer your opinion relative to the questions below. It is not the intent of the drafting team to prepare formal responses to the questions below; we are solely interested in industry opinions on these issues.

We would like to better understand the various generation supply adequacy requirements that have transmission-related implications, implied or specified. This will assist in further development of MOD-004-01 CBM.

What entity is responsible for establishing your Generation Reserve and Resource Adequacy requirements (commission, region, etc)? Reply:

Summary Consideration: The drafting team thanks all who provided responses. This shall serve as the summary response to all information provided.

Question #12	
Commenter	**Yes** **No** **Comment**
APPA	It is not within the scope of this SDT to deal with resource studies, in fact the glossary states the Resource Planner determines the resource adequacy. Generation Reserves has not been defined in the standards nor has Resource Adequacy.
BPA	For Generation Reserve and Resource Adequacy requirements, BPA follows the procedures developed by the Northwest Power Pool which meet the WECC's Minimum Operating Reliability Criteria. BPA also meets the requirements in the NERC standards for Control Performance BAL-001-0 and Disturbance Control BAL-002-0.
Duke Energy	The NC and SC state commissions exercise their authority in this area by requiring an annual filing by the regulated utilities, which includes the identification and justification of reserve margins.
ERCOT	Within ERCOT, a technical recommendation is developed by ERCOT System Planning, acting as the Planning Coordinator. ERCOT Market Participants can give input to the process through open meetings. The technical recommendation is subject to approval by the ERCOT Board of Directors and the Public Utilities Commission of Texas (PUCT). The technical recommendation stipuates generation reserve and resource adequacy requirements both for long term planning and for operating reserve.
FirstEnergy	The Regional Reliability Organization - ReliabilityFirst
IESO	In Ontario, it would be the IESO and the Ontario Power Authority (OPA) which would be responsible for establishing generation reserve and resource adequacy requirements.
IRC SRC	Unable to provide a specific answer as a group. Gernally speaking, however, it is the region that

Question #12	
Commenter	**Yes** **No** **Comment**
	stipuates generation reserve and resource adequacy requirements both for long term planning as well as for operating reserve. (SRC please note: I'm only speculating. Don't let me put words in your mouth)
ITC	TC does not have a resource adequacy requirement. We must work with the LSEs in our service territory to determine appropriate CBM to plan for. These requirements allow for this to happen.
MEC	It is my understanding of the 2005 Energy Policy Act that the Regional Reliability Organization or NERC can either set the generation reliability criteria or enforce the generation reliability criteria, but it cannot do both. The MRO is in the process of proposing to set the generation reliability criteria as 1 day in 10 years. It will be the responsibility of the Load Serving Entity or its delegate (such as a Planning Reserve Sharing Group) within the MRO to set the reserve margin to meet the 1 day in 10 year criteria. The State will enforce the generation reliability criteria and the Planning Reserve Sharing Group will enforce the reserve margin requirement.
MRO	It is the MRO's understanding of the 2005 Energy Policy Act that the Regional Reliability Organization or NERC can either set the generation reliability critiera or enforce the generation reliability criteria, but it cannot do both. The MRO is in the process of proposing to set the generation reliability criteria as 1 day in 10 years. It will be the responsibility of the Load Serving Enetity or its delegate (such as a Planning Reserve Sharing Group) within the MRO to set the reserve margin to meet the 1 day in 10 year criteria. The State will enforce the generation reliability criteria and the Planning Reserve Sharing Group will enforce the reserve margin requirement.
Nova Scotia Power	NPCC sets LOLE standards.
PSC of SC	PSCSC reviews reserve margin / resource adequacy of regulated electric utilities in Integrated Resource Plans.
Salt River Project	SRP sets its Generation Reserve and Resource Adequacy requirements in accordance with WECC Standards.

13. With respect to draft standard MOD-004-1 R5.4, what type of deterministic and probabilistic studies do you perform or what rules do you follow to determine a Load Serving Entity's quantity of CBM? Some examples:

- A Loss of Load Expectation (LOLE) study based on a Loss of Load Probability (LOLP) that allows or establishes a transmission requirement for access to external resources.
- A statutory obligation to meet a regional standard (which might also be an LOLE requirement). What is the transmission requirement if definable?
- A statute with a defined transmission obligation implied or specified.
- A generation requirement, such as loss of the largest unit, which can be interpreted to require access to external resources to cover the loss of the resource. Reply:

Summary Consideration: The drafting team thanks all who provided responses. This shall serve as the summary response to all information provided.

Question #13	
Commenter	
APPA	It is not within the scope of this SDT to deal with resource studies, in fact the glossary states the Resource Planner determines the resource adequacy. LOLE and LOLP are methods used by the Resource Planners.
Duke Energy	None
ERCOT	CBM is not used within ERCOT,
FirstEnergy	Currently the ISO determines CBM via an LOLE study based on 1/10 of a day/year. Currently Ohio does not have a requirement for an LOLP. ReliabilityFirst has established a 1 day in 10 year LOLP criteria that is voluntary. In the future, the ISO PRSG may self-contract an LOLP enforcement requirement. It is expected that the ISO market rules will eventually enforce LOLP.
IESO	The IESO uses stochastic tools like GE MARS to establish reserve requirements for meeting loss of load expectations (LOLE). However, for Ontario, the concept of CBM is not used and is set to 0.
ISO SRC	Unable to provide a specific answer as a group. Again, the LOLE approach is rather commonly used by the ISOs and RTOs in assessing resource adequacy. (SRC please note: ditto the above)
ITC	ITC does not have a requirement, although we are familiar with the LOLE/LOLP evaluations. We strongly believe that R6 is a must for this standard. We have heard estimates that as much as 90% of the load in this country is subject to LOLE requirements based on LOLP studies. To not have requirements in this area would be negligent.
MEC Trading	LOLE study
MEC	I would prefer an LOLE study requirement to support the CBM requests of the Load Serving Entities.
MRO	MRO would prefer an LOLE study requirement to support the CBM requests of the Load Serving Entities.

Question #13	
Commenter	
Nova Scotia Power	LOLE simulations with assumed transmission capacity, however the answer is around 20% reserve
PSC of SC	Our comments are from a regulatory perspective. This is strictly a technical issue.
Southern Co Svcs	Addressing these concerns should be the role of the resource adequacy drafting team and should be handled in the resource adequacy standard.
Salt River Project	SRP's current planning reserve target is based on historical study work that considered unit availability, load uncertainty, and projected costs associated with carrying different levels of reserves.