Background

The Determine Facility Ratings, System Operating limits and Transfer Capabilities Standard Drafting Team thanks all those who submitted comments with the last posting of the standard. After careful review and consideration of all comments received, the drafting team has modified the standard and is posting it for a 30-day review period, prior to ballot.

The SDT's most significant changes include the following:

- The links between the Measures and the Compliance Monitoring Sections of the standard have been modified to ensure that the information to be available to the compliance monitor is clearly specified.
- Additional language has been added to specify which of the requirements and measures are applicable to methodologies developed for use for planning as opposed to operating purposes. The Functional Model assigns the Planning Authority the responsibility of ensuring there is a long-term plans and indicates that these are generally 1 year and beyond – this has been supported in the revised standard.
- Version 2 of the Functional Model is silent on the use of SOLs except for real-time operations and operations planning. The SDT recognized that SOLs are used for developing and analyzing transmission system plans. The SDT asked the Functional Model Review Task Group (FMRTG) to provide a formal interpretation of this omission, and has received a response indicating that the Planning Authority does have responsibility for developing SOLs used in the planning horizon. To support this, the SDT modified Requirement 603 to more clearly indicate that the RA is responsible for having and sharing its methodology for developing SOLs used in the operating horizon and the PA is responsible for having and sharing its methodology for developing SOLs used in the planning horizon.
- Version 2 of the Functional Model is unclear as to which function is responsible for developing SOLs. The following conflict exists on page 25 of the Functional Model, under the TOP's list of tasks:

  2. Defines operating limits, develops contingency plans, and monitors operations of the transmission facilities under the Transmission Operator's control and as directed by the Reliability Authority.

  8. Operates or directs the operations of the transmission system within equipment and facility ratings established by the Transmission Owners and Generator Owners, and system ratings established by the Reliability Authority.
- For this standard, the SDT assumed that the RA is responsible for establishing all SOLs for its RA Area - but may delegate part of this activity to its TOPs. Without formal delegation, the TOP is not responsible for developing any SOLs – and the FMRTG endorsed this assumption in its response to the SDT's request for a formal interpretation of the Functional Model.
- With this clarification on the Functional Model, the SDT was able to modify Requirement 603 to clarify which entity is responsible for the methodology for developing System Operating Limits used for planning purposes and which entity is responsible for the methodology for developing system Operating Limits used for operations. The revised Requirement 603 does not require the TOP or

the TP to develop a SOL methodology. Under the revised standard, the RA will share its methodology with its TOPs – and the TOPs will be required to use this methodology in Requirement 604. The PA will share its methodology with its TPs, and the TPs will be required to use this methodology in Requirement 604.

– Requirement 603 was also modified to add a requirement that the System Operating Limits methodology address credible multiple element outages if required by the associated Region.

– Cross references within the standard have been minimized to make the standard easier to understand.

The SDT feels that additional postings of this standard for comment will not result in any additional significant changes to the standard and is moving the standard forward for its initial ballot.

The second version of the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard was posted for comment from December 1, 2003 through January 21, 2004. The SDT received 43 sets of comments, representing 170 different individuals from 89 entities in 6 of the 9 Industry Segments, and all NERC Regions as shown in the following table:

Commenter "I" indicates a comment submitted by an individual "G" indicates a comment submitted by one of the groups listed at the end of the table	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Dan Boezio (G)	AEP	x								
Paul Johnson (I)	AEP	x		x		x	x			
Scott Moore (G-2)	AEP	x								
Darrell Pace (G-1)	Alabama Electric	x								
Ken Skrobak (G-7)	Alabama Electric Coop	x								
Pamela Mclean (G-10)	Alberta Electric System Operator		x							
Pamela Mclean (I)	Alberta Electric System Operator		x							

Ken Githens (I)	Allegheny Energy Supply					x				
William Smith (I)	Allegheny Power	x								
Kirit Shah (I)	Ameren	x								
Jason Shaver (I)	American Transmission Co	x								
Peter Krzykos (G-10)	Arizona Public Service Co	x								
Mathew Stoltz (G-10)	Basin Electric Power Cooperative	x								
Vance Crocker (G-10)	Black Hills Power	x								
Barbara Rehman (G-12)	BPA Transmission Business Line	x								
Dick Spence (G-12)	BPA Transmission Business Line	x								
Don Gold (G-12)	BPA Transmission Business Line	x								
Jamie Murphy (G-12)	BPA Transmission Business Line	x								
John Kerr (G-12)	BPA Transmission Business Line	x								
Kyle Kohne (G-12)	BPA Transmission Business Line	x								
Marv Landauer (G-12)	BPA Transmission Business Line	x								
Mike Viles (G-12)	BPA Transmission Business Line	x								
Ravi Aggarwal (G-12)	BPA Transmission Business Line	x								
Phil Park (G-10)	British Columbia Transmission Corp	x								
Ed Riley (G-11)	CA-ISO		x							
Ed Riley (I)	CA-ISO		x							
Gary DeShazo (G-10)	CA-ISO		x							
Brad Calhoun (G-15)	CenterPoint Energy	x								

Dennis Caufield (G-15)	CenterPoint Energy	x								
Don Chandler (G-15)	CenterPoint Energy	x								
Glenn Hemperley (G-15)	CenterPoint Energy	x								
James Hayes (G-15)	CenterPoint Energy	x								
John Jonte (G-15)	CenterPoint Energy	x								
Paul Rocha (G-15)	CenterPoint Energy	x								
Richard Sikes (G-15)	CenterPoint Energy	x								
Wayne Kemper (G-15)	CenterPoint Energy	x								
Roger Westphal (G-9)	City of Gainesville			x						
Alan Gale (G-9)	City of Tallahassee					x				
Herman Dyal (G-9)	Clay Electric Cooperative			x						
Rob Remley (G-9)	Clay Electric Cooperative			x						
Keith Comeaux (G-2)	CLECO	x								
Matt Bordelon (G)	CLECO	x								
Bob Kotecha (I)	Consolidated Edison									
Bob Pierce (G-13)	Duke Power	x								
Brian Moss (G-1)	Duke Power	x								
Chris Schaeffer (G-13)	Duke Power					x				
Don Reichenbach (G-13)	Duke Power	x								
Don Reichenbach (G-7)	Duke Power	x								
Tom Pruitt (G-13)	Duke Power	x								

Kham Vongkhamchanh (G-1)	Entergy	x								
Ed Davis (I)	Entergy Services	x								
Ray Morella (I)	FirstEnergy	x								
Bill May (G-9)	Florida Municipal Power Agency				x					
Joe Krupar (G-9)	Florida Municipal Power Agency			x						
John Shaffer (I)	Florida Power & Light	x								
Bob Schoneck (G-9)	Florida Power and Light			x						
John Shaffer (G-9)	Florida Power and Light	x								
Linda Campbell (G-9)	FRCC		x							
Patti Metro (G-9)	FRCC		x							
Mark Bennett (G-9)	Gainesville Regional Utilities					x				
Dick Pursley (G-6)	Great River Energy		x							
David Kugel (G-8)	Hydro One Networks	x								
Mark Hanson (G-10)	Idaho Power Company	x								
David Barajas (G-10)	Imperial Irrigation District	x								
Dan Stosick (G-8)	ISO New England		x							
Kathleen Goodman (G-8)	ISO New England		x							
David LaPlante (G-11)	ISO-New England		x							
Mike Gammon (G-2)	KCP&L	x								
Paul Elwing (G-9)	Lakeland Electric					x				
Richard Gilbert (G-9)	Lakeland Electric			x						

John Horakh (I)	MAAC		x							
Allan Silk (G-6)	Manitoba Hydro		x							
David Jacobson (G-14)	Manitoba Hydro	x								
Doug Chapman (G-14)	Manitoba Hydro	x								
Gerald Rheault (G-14)	Manitoba Hydro	x								
Robert Coish (G-14)	Manitoba Hydro	x								
Robert Coish (G-6)	Manitoba Hydro		x							
Ron Mazur (G-14)	Manitoba Hydro	x								
Ron Mazur (I)	Manitoba Hydro	x								
Joe Knight (G-6)	MAPP		x							
Tom Mielnik (I)	MidAmerican Energy			x						
Terry Bilke (I)	Midwest ISO		x							
Bill Phillips (G-11)	Midwest ISO		x							
Paul Koskela (G-6)	Minnesota Power		x							
Alan Johnson (I)	Mirant						x			
David Weekley (G-1)	Municipal Electric Authority of GA	x								
Barry Gee (G-8)	National Grid US	x								
John Swanson (G-6)	Nebraska Public Power		x							
Alan Boesch (I)	Nebraska Public Power District	x								
Tony Elacqua (G-8)	New York ISO		x							
Ralph Rufrano (G-8)	New York Power Authority	x								

Chuck Stigers (G-10)	Northwest Energy	x								
Guy Zito (G-8)	NPCC		x							
Carl Tammer (G-11)	NYISO		x							
Robert Waldele (I)	NYISO		x							
Alan Adamson (I)	NYSRC		x							
John Mayhan (I)	Omaha Public Power District	x								
Todd Gosnell (G-6)	Omaha Public Power District		x							
Larry Larson (G-6)	Otter Tail Power		x							
Ben Morris (G-10)	Pacific Gas & Electric Co	x								
Craig Quist (G-10)	Pacificorp	x								
Bruce Balmat (G-11)	PJM		x							
Joe Willson (I)	PJM		x							
John Collins (G-10)	Platte River Power Authority	x								
Kenneth Dillon (G-10)	Portland General Electric Co	x								
Howard Guggle (G-9)	Progress Energy			x						
Tom Green (G-10)	Public Service Company of Colorado	x								
Joe Seabrook (G-10)	Puget Sound Energy	x		x						
Charles Yeung (I)	Reliant Energy					x				
Chuck Russell (G-10)	Salt River Project	x								
Abbas Abed (G-10)	San Diego Gas and Electric Co	x								
C.V. Chung (G-10)	Seattle City Light				x					

Charles Wubbena (G-9)	Seminole Electric Cooperative				x					
Garl Zimmerman (G-9)	Seminole Electric Cooperative					x				
Ken Bachor (G-9)	Seminole Electric Cooperative				x					
Steve Wallace (G-9)	Seminole Electric Cooperative				x					
Carter Edge (G-7)	SEPA				x	x				
Lynna Estep (G-7)	SERC		x							
Pat Huntley (G-1)	SERC		x							
Susan Morris (I)	SERC		x							
Bob Jones (G-1)	SERC Planning Standards Subcommittee	x								
Joe Tarantino (G-10)	Sierra Pacific Power Company	x								
John Martinsen (G-10)	Snohomish County Public Utility District				x					
Al McMeekin (G-3)	South Carolina Electric & Gas	x								
Charles White (G-3)	South Carolina Electric & Gas	x								
Clay Young (G-3)	South Carolina Electric & Gas			x						
Gene Delk (G-3)	South Carolina Electric & Gas	x								
Gene Delk (G-7)	South Carolina Electric & Gas	x								
Gene Soult (G-3)	South Carolina Electric & Gas					x				
Johnny Martin (G-3)	South Carolina Electric & Gas			x						
Lee Xanthakos (G-3)	South Carolina Electric & Gas	x								
Peter Chow (G-3)	South Carolina Electric & Gas			x						
Phil Kleckley (G-3)	South Carolina Electric & Gas			x						

Art Brown (G-1)	South Carolina Public Service Authority	x								
William Gaither (G-7)	South Carolina Public Service Authority	x								
Dan Kay (G-7)	South Mississippi Electric Pwr Assoc	x								
Neil Shockey (I)	Southern California Edison					x				
Dana Cabbell (G-10)	Southern California Edison Company	x								
Joel Dison (G-4)	Southern Co Gen & Energy Mktg					x	x			
Lucius Burris (G-4)	Southern Co Gen & Energy Mktg					x	x			
Roger Green (G-4)	Southern Co Gen & Energy Mktg					x				
Roman Carter (G-4)	Southern Co Gen & Energy Mktg					x	x			
Terry Crawley (G-4)	Southern Co Gen & Energy Mktg					x				
Tony Reed (G-4)	Southern Co Gen & Energy Mktg					x	x			
Bob Jones (G-5)	Southern Co Services	x								
Chuck Chakravarthi (G-5)	Southern Co Services	x								
Gwen Frazier (G-5)	Southern Co Services	x								
Marc Butts (G-5)	Southern Co Services	x								
Mike Miller (G-5)	Southern Co Services	x								
Mike Oatts (G-5)	Southern Co Services	x								
Monroe Landrum (G-5)	Southern Co Services	x								
Mike Miller (G-7)	Southern Company	x								
Pamela Johnson (G-10)	Southwest Transmission Cooperative, Inc	x								
Carl Monroe (G-11)	SPP		x							

Robert Rhodes (G-2)	SPP		x							
Bob Cochran (G)	SPS	x								
Ron Donahey (G-9)	Tampa Electric Company			x						
Don Tench (G-11)	The IMO		x							
Khaqan Kahn (I)	The IMO		x							
Al Miller (G-8)	The IMO (Ontario)		x							
Roger Champagne (G-8)	TransEnergie (Quebec)	x								
Peter Mackin (G-10)	Transmission Agency of Northern California	x								
Mary Ann Tilford (G-10)	Tucson Electric Power	x								
Byron Stewart (G-1)	TVA	x								
Mark Creech (I)	TVA									
Mike Clements (G-7)	TVA	x								
Jay Seitz (G-10)	US Department of Interior Bureau of Reclamation				x					
Darrick Moe (G-6)	WAPA		x							
Lloyd Linke (G-6)	WAPA									
Milt Percival (G-10)	WAPA - DSW	x								
Chifong Thomas (G-10)	WECC Tech Studies		x							
Allen Klassen (G-2)	Westar	x								
Connie Osthermann (G-2)	Westar	x								
Rick Stegehuis (I)	Wisconsin Electric Power Co			x	x	x				
Martin Trence (G-6)	Xcel Energy		x							

G-1 – SERC Planning Standards Subcommittee
G-2 – Operating Reliability Wkg Grp for SPP
G-3 – South Carolina Electric & Gas
G-4 - Southern Co Gen & Energy Mktg
G-5 – Southern Company Services
G-6 – MAPP Operations Subcommittee
G-7 – SERC Operations Planning Subcommittee
G-8 – NPCC CP9 Reliability Standards Working Group
G-9 – FRCC
G-10 – WECC Technical Studies Subcommittee
G-11 –Standards Review Committee of ISO/RTO Council
G-12 – BPA Transmission Business Line
G-13 – Duke Power SAR 600 Comment Drafting Team
G-14 – Manitoba Hydro
G-15 – CenterPoint Energy

Index to Questions, Comments and Responses:

1. Is Requirement 603 clear as revised?

Requirement 603 has been rewritten to clarify and amplify the material contained in the table present in the earlier version of this draft standard. The underlying requirements in that table were not modified. Is it clear that system limits may have to be adjusted during long term outages to reflect the requirement that load shedding and/or system reconfiguration will not be permitted for a first contingency on any generator, transmission circuit or transformer except when such an element is part of a single circuit radial connection?

Summary Consideration: Most industry commenters indicated that the revisions need more clarification. While there were many suggestions for additional clarifications, most suggestions included one or both of the following:

(3) Clarify that there is a requirement to recalculate/adjust SOLs post-contingency or to reflect changes in topology
(4) Clarify the distinction between what is expected of the methodology for developing SOLs used for planning purposes from the methodology for developing SOLs used for operations purposes.

The standard has been revised to clarify these areas. Requirement 603 was subdivided so that there is a requirement for the PA to develop and share its methodology for developing SOLs and a separate requirement for the RA to develop and share its methodology for developing SOLs. Specific language was added to state that PA's methodology shall be applicable for use in the planning horizon, and the RA's methodology shall be applicable for use in the operations horizon. The revised standard also states that in the determination of System Operating Limits, the system condition used shall reflect actual or expected system conditions and shall reflect changes to system topology such as Facility outages

Commenter	Yes	No	Comment
Allegheny Energy Supply Segment # 5 Ken Githens		X	The section is confusing on what limits are determined by planning or operating studies. Response: This requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.
Allegheny Power Segment # 1 William J. Smith		X	This section does not differentiate sufficiently between planning and operating studies. Sections 603(a)(3)(iii-iv) are unclear as to what studies are being referenced. Response: Specific references to operations and planning studies were confusing and have been omitted. The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.

AEP Segment # 1,3,5,6 Paul Johnson		X	The issue was clear only by providing the example in the above question. Clearer language in the standard would be appropriate Response: The standard has been rewritten to add greater clarity.
Peter Burke American Transmission Company Segment # 1		X	This requirement is written so that the Reliability Authority, Transmission Operator, Planning Authority, and Transmission Planner shall all document the methodology used. It does not require that they all use the same methodology nor does it address the question of which entity is ultimately responsible. The SDT seems to want these four entities to work together but that is not made a requirement as the standard is currently written. Response: The standard has been revised to state more clearly that the RA and PA must each have and share their methodologies for developing SOLs. The standard does not require the RA and PA to have the same methodology, but their methodologies need to meet appropriate criteria. The revised standard requires the RA to share its methodology with other RAs, and with its PAs and TOPS – and requires the PA to share its methodology with other PAs, and its RAs and TPs. These entities may all work together to develop a single methodology – but the standard does not require this. This standard recognizes that a radial customer is exposed to risk of loss of service but does not address how much risk is acceptable. That leaves an entity free to accept any amount of first contingency risk as long as that risk entails only loss of load and not cascading or wide area outages. This allowance may lead to the unintended consequence of unusually large loads exposed to unusually long outages resulting from first contingency events. For example, through planning, a planned outage, or a forced outage, a large load could be left dependent on a large power transformer or underground transmission line. Any limit to what risk is allowed is removed when this standard accepts that a radial load may be put at risk of the next contingency. Would this rule be applied to the 69 kV transmission system? Response: The standard is not the place to dictate the level of risk that is acceptable, as this is outside of the scope of NERC's standards. If the 69 kV system is part of the networked bulk electric system this standard would apply.
California ISO Segment 2 Ed Riley		X	The intent of Requirement 603 was not clear until reading the explanation that accompanies this question. The limits should be adjusted for changes in topology, if necessary. Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
CenterPoint Energy Segment 1 Don Chandler		X	The question asks if it is clear that "system limits may have to be adjusted during long term outages". Yes, this is clear. In fact, 603(a)(3)(iii)(A)(f) clearly allows for system reconfiguration following a first contingency: "System adjustment or reconfiguration is permitted…". The question also asks if it is clear that ". . . load shedding and/or system reconfiguration will not be

			permitted for a first contingency . . .", except for radially connected loads. This is less clear. Regarding load shedding: load shedding (other than radially connected or directly impacted loads) is not permitted in 603(a)(3)(iii)(A)(e) for a Category B (single contingency) condition. Additionally, this is consistent with the Planning Standard. However, as noted above, system reconfiguration is permitted by 603(a)(3)(iii)(A)(f) following a first contingency. However, the question, coupled with the conclusion of the provided example, seems to imply that load shedding would not be permitted for a condition that qualifies as Category C (double contingency) from a planning perspective. It is not clear that such actions would be prohibited. In fact, such a conclusion is an inappropriate interpretation of Requirement 603 in that it restricts load shedding for any subsequent contingency after a first contingency (an n-2 or Category C condition). This conclusion is also inconsistent with 603(a)(3)(iv)(A)(f) that permits interruptions after subsequent contingencies. The Planning Standard permits load shedding for this set of circumstances. A system designed to the Planning Standard may need to shed some load (not limited to radially connected load) for the next (n-2) contingency. The operator may not have another operating option other than load shedding because no other option was designed into the system for this set of circumstances. It is unreasonable to prohibit an operating action that was contemplated in the design of the system for the specified set of circumstances. For this same reason, the permission, but not the requirement, of system reconfiguration following a first contingency that seems to be allowed in 603(a)(3)(iii)(A)(f) is appropriate and should remain in the standard. Further, the question refers to "long term outages" but the proposed Standard does not have a comparable reference. What may constitute "long term" is somewhat subjective and could reasonably mean different time frames in different circumstances. Requirement 603 does not specify any time frame or circumstance after which an n-1 condition becomes a new n-0 condition. Response: This requirement has been revised to improve its clarity. The standard does not prohibit an operating action that was contemplated in the design of the system. The timeframes for response are addressed in the Operate within IROL standard or operate within System Operating Limits Standard.
Duke Power Segments 1, 5 Tom Pruitt		X	Overall, the revised standard is now more confusing than the first draft. Section 603 is very difficult to understand. In attempting to clarify how to apply the I.A standard contingency table in version 1, it is now unclear as to what contingencies should be considered in which horizon (operating vs. planning) and what operating actions are allowable to prevent exceeding of operating limits. This section does not clearly differentiate between various time horizons (e.g., real time, next day, operational planning (up to 18 mos., usually), and long term planning (greater than 18 mos.). The distinctions made do not clearly map to the time frames currently known and used. Response: This requirement has been subdivided to improve its clarity. In the revised standard, the PA

			and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon. In addition, a requirement was added for the RA and PA to have an agreement with one another on the time horizons addressed by each of their methodologies.
Entergy Segment 1 Ed Davis		X	We see several potential problems reflected in this first question. First, we have the understanding that the base case load flow models used to estimate SOLs should reflect the power system and the expected in-service/out-of-service condition of all of the elements of the power system under examination. This base case load flow model reflection of the condition of the elements of the power system applies to all base case load flow models: planning, operations planning, operations, etc., not just longer-term planning models. All SOLs should be redetermined when those expected in-service/out-of-service conditions change in the planning, operations planning, operations, etc horizons. Therefore, we suggest an obvious statement be placed in the Standard to the effect that SOLs are redetermined whenever the power system elements in-service change from those contained in the base case load flow models when SOLs were determined. Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. Second, we have been unable to find any place in the Standard that would restrict load shedding and/or system reconfiguration requirements because an element is out-of-service. Therefore, in response to the posed question, it is not clear that the Standard does "reflect the requirement that load shedding and/or system reconfiguration will not be permitted for a first contingency on any generator, transmission circuit or transformer except when such an element is part of a single circuit radial connection". Response: This question was poorly worded by the drafting team. Load shedding for n-1 would not be permitted during the course of planning studies with future system intact. Load shedding may be required operationally to withstand n-1 if a major system component has already been lost and this has been clarified in the revised standard. Third, the Standard does permit system adjustments, interruption of load or system configuration in response to contingencies. We believe there should be no need to change the rules for load shedding and/or system reconfiguration under contingency conditions when SOLs are redetermined to reflect expected in-service conditions of the elements of the power system. Response: This is consistent with the standard.
FirstEnergy		X	If the condition indicated above is intended to be covered, as I think it should, it should be stated more directly. Possible wording could be that an outage that will extend through an entire summer or winter

Segment 1 Ray Morella			peak loading season would apply Response: The standard has been clarified to address your comment. Our question was worded poorly.
Florida Power & Light Segment 1 John Shaffer		X	System Operating Limits should be recalculated whenever there are significant equipment outages; however, it is clear that load shedding and/or system adjustments are permitted as described in 603 (3) (iv) (e) and (f). Response: Agreed.
FRCC Segment 2 Endorsed by 10 FRCC Members Segments 1,3,4,5 Patti Metro		X	This section is very unclear. What is the difference between planning studies and operating studies? Response: The standard has been revised to indicate that the RA and PA are each responsible for developing a methodology for determining SOLs. The RA's methodology shall be applicable for developing System Operating Limits used in the operations horizon – and the PA's methodology shall be applicable for developing System Operating Limits used in the planning horizon. We do not believe that it is clearly stated in Requirement 603 that system limits may have to be adjusted during long term outages to reflect the requirement that load shedding and/or system reconfiguration will not be permitted for a first contingency on any generator, transmission circuit or transformer except when such an element is part of a single circuit radial connection. It is our understanding that this question refers to 603(3)(iv) which states that controlled interruption of load is permitted in subsections (e) and (f). Response: This question was poorly worded by the drafting team. Load shedding for n-1 would not be permitted during the course of planning studies with future system intact. Load shedding may be required operationally to withstand n-1 if a major system component has already been lost and this has been clarified in the revised standard. We do, however, agree that in the example provided that limits would need to be re-established for a loss of equipment that cannot be replaced for an extended period of time.
Independent Electricity Market Segment 2 Khaqan Khan		X	It is not clear in Standard 603 that system limits may have to be adjusted during long term outages to reflect the requirement that load shedding and/or system reconfiguration will not be permitted for a first contingency on any generator, transmission circuit or transformer except when such an element is part of a single circuit radial connection. Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. Load shedding and/or system adjustments are permitted. Additionally, the IMO has some fundamental concerns with Standard 603. Firstly, while the standard 603 promotes a post performance criteria that must be observed, there is no

			clear methodology or practice identified for the establishment of System Operating Limits. For example, Standard 601 (a)(3) identifies industry rating practices or other standards (IEEE, ANSI, CSA etc) to provide for a consistent methodology to be used in the establishment of ratings across the industry. It is the IMO's position that a consistent methodology or acceptable industry practices should be identified 603(a)(4) to recognize the acceptable and critical assumptions and methods for addressing items (i to v) when satisfying the post performance criteria in Standard 603(a)(3). This should ensure the methodology used by one RA to determine System Operating Limits (and IROL) do not place another RA's jurisdictions at risk. With regards to 603(a)(4), the methodology must also address the scope of assumptions, i.e. the assumptions must be wide enough to recognize electrical performance, not just owner or jurisdictional territory. These comments can be equally applied to the methodologies for 605. Response: The standard intentionally does not dictate the methodology to be used, but rather leaves it to the developers of the SOL methodologies. Requirement 601 does not require the use of a single methodology for rating facilities. The revised standard requires that methodology developers provide their methodologies to other entities. Secondly, it is not clear that System Operating Limits (SOL) need to be recalculated as the system topology changes anywhere in Requirement 603 or its associated measures **T**o make it clear, the IMO believes a statement, similar to the one used in the Operate Within IROL Requirement 201 Measure 1.i should be included so that there is no mistake with respect to the requirement to revise SOL's as topology changes. (201.b.1.i states, "the RA shall have evidence that it reviews and updates the list of facilities to reflect changes in system topology"). The example above, leads one to believe that SOLs only need to recalculated where the outage is of an extended nature. While this may be true for a base set of limits for the planning time frame, in fact all SOLs (and IROLs) need to be constantly reviewed and revised (or have the training and tools available to establish safe operating postures following a contingency) to reflect the real-time system configuration. If this is action is not taken,the RA or other authority will not be able to respect T_v as stated in Standard 200. Therefore this requirement should not only identify a need to revise the SOL, but should also indicate the timeliness of updates to cover both the planning and the real-time determination of SOLs (and IROL). Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility

			outages. The update frequency will be governed by the schedule used to exchange SOLs and the methodology used to determine them, as required in the standard. The IMO is not advocating that the "Authorities" operators have SOLs available to them for all the possible configurations. Rather the IMO believes that these operators should have the capability (Tools and / or Training) at their disposal to identify and deal with unforeseen circumstances or conditions where they are no longer operating within the boundaries of the studied limits. As a minimum, the operators should have at their disposal a base set of limits that include N-1 configurations, along with identifying the following: • The boundary conditions for which the published limits are applicable, • The critical contingency that drive the applicable limit and • An understanding of what the associated limit is designed to protect the system against (i.e. transient stability, voltage decline etc) Response: **The drafting team agrees with these comments but feels that this information should be addressed in the Standards for operating within limits.**
ISO/RTO Council Segment 2 Endorsed by 7 IRC Members Bruce Balmat		X	Include requirements that: 1. Limits need to be modified for topology changes. Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. 2. Tools or procedures should be required to allow this modification to ratings in real-time (or close to real time). Response: This is an implementation issue; it is not incompatible with this standard. 3. Standard rating practices should be identified to provide consistent methodologies for determining ratings, security limits or transfer capabilities. **Response:** "The equipment in service in the North American power system has been provided by various manufacturers over a period of more than 75 years. There is no consistency with respect to manufacturer, initial design criteria, manufacturing quality, age, maintenance condition, climatic conditions, operational history, or local operating or safety standards and laws. Any standard rating methodology or methodologies would be so high level as to be meaningless. The application of a

			standard methodology, if one could be developed, would mean that equipment owners could be exposed to unwarranted risk or the system would be unnecessarily constrained."
MAAC Segment 2 John Horakh		X	What is not clear (i.e. is not stated) is that for an outage that lasts for some time (24 hours?) the system must be readjusted to achieve pre-contingency conditions, as in 603(a)(3)(i). Section 603(a)(3)(iii)(f) only states that readjustment is permitted; something should be added to state it is required. Also, Section 603(a)(3)(iv) should be eliminated and a note added in 603(a)(3)(iii) to state that interruption of load is permitted for Subsequent Contingencies only. I think this is the only difference between (iii) and (iv). Response: These sections have been revised to add clarity.
Manitoba Hydro Segment 1,3,5,6 Gerald Rheault & Ron Mazur		X	While it is clear in standard 603 that system adjustments or reconfigurations may be necessary to prepare for the next contingency (i.e. 603 (3) (iii) (A) (g)), there are several aspects that are not clear. What is the permissible readjustment period (e.g. 30 minutes or several months as in your 345 kV transformer example)? Response: Adjustment periods are specified in the Operate Within IROL standard. In 603 (3) (iv), is the subsequent contingency within the readjustment period (i.e. within 30 minutes of the first contingency) or following all necessary system readjustments? You mention above that load shedding and/or system reconfiguration will not be permitted for a first contingency and yet in 603 (3) (iii) (A) (f), system adjustment or reconfiguration is permitted for a single contingency. Response: Subsequent contingency was intended to mean a contingency to a system that has already suffered one or more outages – the system is assumed to have been adjusted after the preceding outage(s). Please clarify exactly what adjustments or reconfigurations are permissible (e.g. spinning and non-spinning operating reserve, capacitor/reactor switching, load tap changers, phase shifters, HVdc converters, generator rejection, transmission reconfiguration, non-firm load shed). Response: Nothing listed above would be prohibited. Because each entity has different resources available, the standard does not limit any system adjustments. A definition for "post contingency time frame" should be provided as part of the definitions. Also what is meant by "applicable post contingency limits" Response: This portion has been reworded to add some clarity. The standard no longer uses the term, 'post contingency time frame'.
Mirant Segment 6		X	The proposed language does not make this point clear. Response: This section has been revised to add clarity.

Alan Johnson			
NYISO Segment 2 Robert Waldele		X	The section now seems to gray the boundary between planning and operating studies. One can get the impression that "day-ahead" is planning, and real-time is operating. This question and example seem to raise a concern that system operating limits do NOT have to be adjusted for a short-term outage: 603.a.3.iv should clearly state (at the outset) that following a contingency "System Operating Limits" (may) need to be (re) determined. Response: This requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon. The standard has also been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
NPCC CP9 Segment 2 Endorsed by 7 Members Guy Zito		X	NPCC feels the language is insufficient to require recalculation during long-term outages. The Standard needs to specify recalculation of the SOLs and IROLs on a regular basis from real time through planning timeframes or every time that conditions change. The Standard should identify when the limits should be recalculated. Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. The update frequency will be governed by the schedule used to exchange SOLs and the methodology used to determine them, as required in the standard.
OPPD Segment 1 John Mayhan		X	The standard as currently written could easily be interpreted as saying that any forced outage, regardless of its time duration, places the system in a state where the requirements of Section 603(a)(3)(iv) apply; Section 603(a)(3)(iv) allows both load shedding and system reconfiguration in response to a contingency. Additionally, even Section 603(a)(3)(iii) allows system reconfiguration in response to a contingency. Response: These comments are consistent with the standard. The example given in the question implies that a forced outage is to be considered "planned maintenance" at some point in time after its occurrence. If this is true, then the standard should be modified to make this very clear. Additionally, if a forced outage is to be considered "planned maintenance" at some point in time after its occurrence, then at what point in time does this transition occur? The point in time at which this transition occurs needs to be clearly specified; otherwise, confusion and inconsistency in interpretation of the standard will result.

			Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
PJM Segment 2 Joe Willson		X	What is not clear (i.e. is not stated) is that for an outage that lasts for some time (24 hours?) the system must be readjusted to achieve pre-contingency conditions, as in 603(a)(3)(i). Section 603(a)(3)(iii)(f) only states that readjustment is permitted; something should be added to state it is required. Response: System reconfiguration is permitted, but not required under the standard. It may not be necessary to reconfigure after the outage. Also, Section 603(a)(3)(iv) should be eliminated and a note added in 603(a)(3)(iii) to state that interruption of load is permitted for Subsequent Contingencies only. Response: The standard has been revised to add clarity.
SERC Segment 2 Susan Morris SERC Planning Standards SubCommittee Segment 2 Endorsed by 7 Members Segment 1 Bob Jones Southern Co Services Segment 1 Marc Butts Southern Co Gen & Energy Marketing Segments 5,6 Roman Carter		X	This whole section is unclear on the difference between planning and operating studies. Is this section specifically dealing with operational horizon (less than 18 months) Next-Day (day ahead planning) and Real-time (operating) studies? Does this section have anything to do with planning horizon (18 months and out) studies or is that still being handled by the existing NERC Planning Standards (Table I.A. and associated measures) or a future standard (Assess Transmission Future Needs and Develop Transmission Plans). The contingencies seem to follow existing Category A, B, and C descriptions, but it's not clear what 603(a)(3)(i)(B-C) "planning purposes" vs. "operations" is saying and what studies the headers for 603(a)(3)(iii-iv) are referencing "on the planned system" vs. "operations studies only". Response: Specific references to operations and planning studies were confusing and have been omitted. The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.
SERC Operations Planning SubC Segment 2		X	The requirement to recalculate/adjust SOLs post-contingency is not clear. This requirement is ultimately important in maintaining the reliability of the Interconnection. As a best practice, it should indicate that these recalculations/adjustments should be done on an ongoing basis to accommodate system changes

Endorsed by 8 Members Segments 1,4,5 Don Reichenbach			(changes in generation, contingencies, etc.) Also, the necessary adjustments vary according to which timeframe is being studied, i.e., real-time is very different from the planning timeframe, with the operational planning timeframe falling somewhere in between. The standard needs clarity in this section and throughout on the differences between the different timeframes (real-time, day-ahead, operational planning, and planning.) Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. The update frequency will be governed by the schedule used to exchange SOLs and the methodology used to determine them, as required in the standard.
South Carolina Elect & Gas Segments 1,3,5 Clay Young		X	This section needs clarification on the operating and planning horizons. It is not clear what time frame the standard is applicable to. Also, same comments as submitted by the SERC Planning Standards Subcommittee. Response: Specific references to operations and planning studies were confusing and have been omitted. The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.
SPP Operating Reliability Group Segment 2 Endorsed by 5 Members, Segment 1 Scott Moore		X	The proposed standard is not clear that such limits are to be modified for long-term outages. We struggled with this question because we were not exactly sure of the definition of long-term. Also, in the given example, for the next contingency following the loss of the 345 kV transformer, we would be prohibited from utilizing load shedding to operate within the provided limits as indicated in 603(a)(3)(iii)(f). This is too restrictive. Load shedding should be allowed in this situation. Response: Long-term does not appear in the standard. Our question was worded poorly. The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
TVA Mark Creech		X	(TVA agrees with the SERC Planning Standard Subcommittee). This whole section is unclear on the difference between planning and operating studies. Is this section specifically dealing with operational horizon (less than 18 months) Next-Day (day ahead planning) and Real-time (operating) studies? Does this section have anything to do with planning horizon (18 months and out) studies or is that still being handled by the existing NERC Planning Standards (Table I.A. and associated measures) or a future standard (Assess Transmission Future Needs and Develop Transmission Plans). The contingencies seem to follow existing Category A, B, and C descriptions, but it's not clear what 603(a)(3)(i)(B-C) "planning purposes" vs. "operations" is saying and what studies the headers for 603(a)(3)(iii-iv) are referencing "on the planned system" vs. "operations studies only".

			Response: Specific references to operations and planning studies were confusing and have been omitted. The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.
Ameren Segment # 1 Kirit Shah	X		Yes with following comments: 1. What is long term? If it is several months, like in example, we agree. If it is anything less than a few days, say a week, we do not agree. Response: Specific references to operations and planning studies were confusing and have been omitted. The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon. 2. Why would system reconfiguration be not allowed, even for a long-term outage? The second paragraph is confusing as it is a long sentence. The sentence may be split to avoid any confusion. Response: System reconfiguration is permitted in the standard, but we worded this question poorly.
Alberta Electric System Operator Segment 2 Pamela Mclean	X		The AESO supports the comments made by to this point by the Standards Review Committee of the iSO/RTO Council Standard rating practices should be identified to provide consistent methodologies for determining ratings, security limits or transfer capabilities. 601 appears to be watered down from the existing NERC std. There is no wording requiring that rating methodologies be based on "good industry practice" or follow applicable industry standards. No requirement for seasonal ratngs or emergency ratings. 601 places no minimums on the quality of the rating methodology to ensure certainity of risk Response: "The equipment in service in the North American power system has been provided by various manufacturers over a period of more than 75 years. There is no consistency with respect to manufacturer, initial design criteria, manufacturing quality, age, maintenance condition, climatic conditions, operational history, or local operating or safety standards and laws. Any standard rating methodology or methodologies would be so high level as to be meaningless. The application of a standard methodology, if one could be developed, would mean that equipment owners could be exposed to unwarranted risk or the system would be unnecessarily constrained." The word 'applicable' in the standard when discussing ratings is intended to address seasonal and

			emergency ratings. Good industry practice is something against which compliance is difficult to measure. The standard is based upon the existing Planning Standard and requires that the methodology used be clearly documented and contain a baseline of fundamental components.
BPA Transmission Segment 1 Mike Viles	X		(No comments)
MAPP Segment 2 Endorsed by 8 Members Lloyd Linke	X		No Comment
MidAmerican Segment 3 Tom Mielnik	X		No Comment
Midwest ISO Segment 2 Terry Bilke	X		No Comment
NPPD Segment 1 Alan Boesch	X		No Comment
NY State Reliability Council Segment 2 Alan Adamson	X		No Comment
WECC TSS Endorsed by 26 Members Segments 1,2,3,4 Chifong Thomas	X		No Comment

2. Do you see a need for contingencies known in the current NERC Planning Standards as "Level C contingencies", such as breaker failure, double circuit loss and bipole block, to be examined to ensure that system cascading, instability and uncontrolled separation do not result at system transfers consistent with the limits developed using this methodology?

Summary Consideration: Most commenters supported this concept but many commenters misinterpreted the intent of this question. The suggested wording was intended to apply to both planning and operating horizon studies and it was not intended to completely address the requirements of level C in the current NERC planning standard (since overloading of facilities was allowed).

The SDT has considered all of the comments received on this question and has added a clause/clauses [see below] to standard 603 requiring consideration of some credible level C events, where the determination of the events to be considered (and the acceptable response) is determined by the region.

The responses showed a significant, but qualified, support for a change in the standard. Many believed that the requirement was appropriate for planning horizon studies only, some believed that the concept was appropriate for both planning and operating while some believed that N-1 (the existing wording) was sufficient for all studies.

In some comments, the SDT was reminded that the current NERC standard on limits contains a clause which enabled regional practices to be a factor in the determination of limits. Some systems or regions are normally thermally limited and consideration of instability, for example, is generally not important. Other systems are stability limited and the considerations contained in the question are important for reliability.

The August 14 disturbance also highlights the need for system operations people to better understand the consequences of likely events. Some multiple contingency events can be a likely to occur as single contingencies. If the consequences of a likely or credible event are catastrophic, then due diligence would require understanding the risk to the interconnection.

It is clear, through the evolution of the standard, that some stakeholders felt that the 600 series standards were a replacement for the current system planning standard. There will be a separate standard (presently at the SAR stage) which will consider studies from a system expansion / capital investment perspective. Standard 603 deals only with the evaluation of reliable system operating limits and does not deal with system expansion. The only link to planning is through the determination of reliable flow limits in the planned system. System planning considerations are broader than just this one point.

From industry comments it is clear that the minimal standard for evaluation of limits is a consideration of only first contingencies (the equivalent of level B in Table 1 of the current planning standard). It is also clear that system reliability requires further considerations in some regions but these considerations do not form a consistent subset of level C considerations across all regions.

The proposed wording in standard 603 provides:

- An enabler for regions to have credible multiple contingencies evaluated in the determination of system operating limits and for this list for contingencies to be less that the full set of level C contingencies. The list could have no entries or it could be as specific as detailing only certain contingencies at certain buses.
- A reduction in the need for a series of regional differences to be embedded in the standard. Similarly, there is a reduced need for those responsible for establishing the methodology for the calculation of system operating limits or those responsible for the determination of

limits to have to be aware of regional standards and to develop methodologies consistent with both the NERC and the regional standard. The proposed standard unifies the consideration of regional needs. [I'm struggling to get the word right here]

- An enabler for the regions to require different contingencies to be considered for planning and operating studies and for the criteria for evaluation of the contingencies to be different for each.
- While not a direct factor, this wording reflects current reliability practice and ensures that it can continue.

Thus, if there are known regional reliability concerns they can be addressed in a tailored, targeted fashion.

The proposed wording does not devalue or modify the two proposed regional / interconnection differences provided by NPCC and WECC. Such regional differences reflect the current system design and operating philosophies of these regions. Rather, it ensures that important reliability considerations will not be lost in the transition to the new standards.

The following has been added to the standard:

If an associated Regional Reliability Organization requires consideration of credible multiple element contingencies:

A) Following a credible multiple element contingency, the system shall meet criteria established by the Region for that contingency.

Commenter	Yes	No	Comment
Mirant Segment 6 Alan Johnson			No Comment
SERC Planning Standards SubCommittee Segment 2 Endorsed by 7 Members Segment 1 Bob Jones			The majority of the PSS feels that this should be a requirement for Planning Horizon SOLs. However, real-time and day-ahead SOLs need only consider the next N-1 contingencies. Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
TVA Mark Creech			(TVA agrees with the SERC Planning Standard Subcommittee). This should be a requirement for Planning Horizon SOLs. However, real-time and day-ahead SOLs need only consider the next N-1 contingencies. Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.

Southern Co Services Segment 1 Marc Butts Southern Co Gen & Energy Marketing Segments 5,6 Roman Carter			We answer both "yes" and "no" on this question. This should be a requirement for Planning Horizon System Operating Limits. However, real-time and day-ahead System Operating Limits need only the next N-1 contingencies. Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
Ameren Segment # 1 Kirit Shah			If it is "local" why would instability (angular) a problem if it does not result in uncontrolled separation? Response: We aren't sure we understand your comment. How is cascading define and how is to be determined? Response: The definition for cascading is still being refined through industry comments. The latest definition will be re-posted with the revised standard. How are "system transfers" defined? Response: The SDT used the term 'system transfers' to mean power flows within system operating limits. The term, system transfers is not used in the standard and has not been defined by the SDT.
AEP Segment # 1,3,5,6 Paul Johnson			The SOL should be determined at the first contingency level, but this SOL would be 'valid' only if cascading, instability or uncontrolled separation does not occur with the loss of a second facility (before adjustment) when the interface/flowgate is operating at the SOL level. Response: Agreed.
Allegheny Power Segment # 1 William J. Smith		X	We would answer "Yes" if this applies only to Planning Studies Response: The draft standard has been revised to clarify that this was intended to address all system operating limits, not just those used in the planning horizon.
ISO/RTO Council Segment 2 Endorsed by 7 IRC Members		X	There should be clear delineation of the time frame being reviewed and analyzed for multiple credible outages. The Planning arena and the real-time Operations expectations must be spelled out with specific measurements and non-compliance elements for each. Response: The standard has been revised to add more clarity to the time frames being addressed in the

Bruce Balmat			various functions.
California ISO Segment 2 Ed Riley		X	This answer is based on the assumption that by "planning", the Standard refers to a time horizon of less than one year from the operations date, or "real-time or near-time planning", which should then be specified in the Standard Response: The standard has been revised to reflect this suggestion. The measurements must be specific and one authority identified as the responsible entity. Response: The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.
CenterPoint Energy Segment 1 Don Chandler		X	It is unrealistic to require the same level of contingency screening in the operating environment as is required in the planning environment. In the operating environment, system conditions are more dynamic and time horizons are much shorter than in the planning environment. Therefore, it is feasible to perform more robust analysis in the planning environment than in the operating environment. **Response: Agreed. However, t**he system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
Duke Power Segments 1, 5 Tom Pruitt	X		Yes, but in the proper time frame. Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
BPA Transmission Segment 1 Mike Viles	X		We believe that it is prudent to examine "Level C contingencies" when planning the system but that decision should left up to the regions. Response: The standard has been revised to reflect this suggestion.
FirstEnergy Segment 1 Ray Morella	X		It seems that if the planning standards require these events be considered and there is an Operating Policy 2 that requires adjustment within 30 minutes to avoid cascading outages for a next contingency that NERC Level Cs should be examined to ensure transfer levels are not exceeded which could cause a cascade for a Level C outage. Having said that, the problem will be setting the bar to measure when the potential exists for a cascading outage. Response: Other standards address the requirements for real-time operations within limits. The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
Florida Power & Light Segment 1 John Shaffer	X		Category C contingencies should be evaluated in the planning horizon so that system design can be adjusted to minimize exposure. Simulation or analysis of category C contingencies in operating time horizons should be at the discretion of the Reliability Authority and Transmission Operators. Response: The SDT defaulted to assigning this discretion to the RRO.

FRCC Segment 2 Endorsed by 10 FRCC Members Segments 1,3,4,5 Patti Metro	X		There is a need to examine "Level C contingencies" in the planning horizon so the system design can be adjusted to maintain reliable system operations. Some Reliability Authorities or Transmission Operators may want to study selected "Level C contingencies" for some operating horizons because of possible real-time issues Response: The SDT defaulted to assigning the responsibility for determining which contingencies should be studied to the RRO.
Independent Electricity Market Segment 2 Khaqan Khan	X		Current NERC Policy 2 A section 1.1 states: " Multiple outages credible nature, as specified by Regional policy, shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages." irit of this statement should be embodied in this standard to ensure that as a minimum, assessments are made of conditions and circumstances where there may be a need to respect multiple contingencies they are respected. **he I** IMO believes that as a minimum, there are attributes of the NPCC policy with respect to multiple element coverage that can be beneficial to the interconnection. For example, for unexplained automatic operations, it may be prudent to operate to a higher level of security (i.e. operate to SOLs that include multiple outages) until the cause of the outage has been positively identified. Response: The standard has been revised to reflect your suggestion.
MAAC Segment 2 John Horakh	X		"Level C contingencies" are appropriate for the Planning Authority and Transmission Planner to examine. This is because the system studied by planners is the "ideal" system with almost everything in service, whereas the system as operated in real time almost always has some elements out already. Therefore the planned system can and should be subjected to more severe contingencies to test its robustness. The contingencies in 603(a)(3)(ii) could then be noted as applicable to all 4 entities (RA, TOP, PA and TP), and additional "Level C contingencies" could be specified as applicable to the PA and TP only Response: The SDT agrees that the planned system should be subject to more severe contingencies. The standard has been revised to clarify that only credible multiple-element contingencies identified by an RRO must be studied. This would be applicable to all system operating limits.
MAPP Segment 2 Endorsed by 8 Members Lloyd Linke	X		With the exception of "Category D" disturbances, the system should not be subjected to instability, uncontrolled separation, or cascading. Response: Agreed.
Manitoba Hydro Segment 1,3,5,6	X		All system operating limits should be checked for instability, cascading and separation for "Level C" contingencies and adjusted to avoid these conditions. This is not the same as establishing limits based on full consideration of level C contingencies but provides an important reliability margin in stability limited systems. A statement to this effect should be added to 603.

Gerald Rheault & Ron Mazur			Response: The standard has been revised to reflect this suggestion.
MidAmerican Segment 3 Tom Mielnik	X		All system operating limits should be checked for instability, cascading and separation for "Level C" contingencies and adjusted to avoid these conditions. This is not the same as establishing limits based upon full consideration of Level C contingencies but provides an important reliability margin Response: The standard has been revised to reflect this suggestion.
Midwest ISO Segment 2 Terry Bilke	X		This however, shouldn't be arbitrary. Such contingencies should be included when history has shown them possible (a particular right-of way or breaker type having multiple occurrences of a common failure). Response: The standard has been revised to reflect this suggestion.
NPPD Segment 1 Alan Boesch	X		Level C contingencies should not cause cascading instability or uncontrolled separation at system transfers consistent with the limits developed using this methodology. Response: Agreed
NYISO Segment 2 Robert Waldele	X		These are normal criteria contingencies in the NPCC Areas. Systems/Areas/Regions that do not have the stringent design criteria similar to NPCC should evaluate system response to these types of contingencies as a relative measure of system strength (robustness). In particular, delayed clearing events are not always the result of breaker failure, but could result from protection failure (where there may not be redundant protection groups). Response: Agreed. The standard needs an explicit reference to the contingencies and their application. Absent an explicit statement, this standard can only be viewed as a weakening of the reliability goals of Operating Policy P2.A.1.1 Response: This standard has been revised to clarify that credible multiple-element contingencies identified by an RRO must be studied. This supports your suggestion.
NY State Reliability Council Segment 2 Alan Adamson	X		Standard 600, as presently proposed, removes "Level C contingencies" that now exist in present NERC criteria, and as a result, weakens existing NERC criteria and reduces reliability. For many years NPCC and New York State Power System reliability criteria have required the system to withstand contingencies involving the loss of more than one element – usually the loss of both circuits of a double-circuit tower line or a fault with a stuck breaker. A major limiting contingency for three Regions – NPCC, MAAC and ECAR – has been the loss of both poles of the bipolar DC line between Radisson, Quebec and Sandy Pond, Massachusetts. Standard 600, without covering "Level C contingencies", would permit this contingency. Not including such contingencies in the criteria would increase transfer capabilities (on paper); however, an increase in the number of cascading outages, system separations, and blackouts could assuredly be expected. We recognize that if NERC does not adopt "Level C contingencies" in Standard 600, NPCC and the New York State Reliability Council (NYSRC) could still maintain their more stringent criteria, i.e., Regional or sub-Regional Standards. However, even then, the reliability of the NPCC Region and the New York State Power System could be jeopardized by inter-Regional impacts caused by the adoption of weakened NERC criteria in other Regions. We also note that "Level D" assessment, evaluation of extreme contingencies, was also not included in Standard 600 or any other

			presently proposed NERC Standard. Although extreme contingency assessment is not normally used for the calculation of transfer limits, it is presently required by the existing NERC Planning Standards "to measure the robustness of electric systems and should be evaluated for risks and consequences" (quoted from NERC Planning Standards IA Introduction). This type of assessment is particularly needed in the aftermath of the August 14, 2003 Blackout. NERC should not weaken its present criteria by elimination of this very important system planning requirement. Response: This purpose of this standard is not to address system expansion issues – this standard's focus is on establishing limits. The standard has been modified to clarify that credible multiple-element contingencies identified by an RRO must be studied. This would be applicable to all system operating limits.
NPCC CP9 Segment 2 Endorsed by 7 Members Guy Zito	X		NPCC feels a statement such as that in NERC Operating Policy 2a Section 1.1, needs to be made consistent with the thought of assessing the effect of "multiple outages of a credible nature Response: The standard has been modified to reflect your suggestion.
PJM Segment 2 Joe Willson	X		Yes but there must be a clear delineation about the time frame being reviewed and analyzed. The Planning arena and the real-time Operations expectations must be spelled out with specific measurements and non-compliance elements for each. Response: The requirement has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon.
SERC Segment 2 Susan Morris	X		This should be a requirement for Planning Horizon SOLs. However, real-time and day-ahead SOLs need only consider the next N-1 contingencies. The Level C contingencies are very important to test the strength of the system. The analyses on level C contingencies, while not as probable, are somewhat of a stress test of the system and help identify weaknesses in the system. This is a vital test for timeframes other than real-time. Real-time and day-ahead analyses do not need to include any contingencies past N-1. The standard would benefit from distinct sections for the various timeframes. Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
SERC Operations Planning SubC Segment 2 Endorsed by 8	X		The Level C contingencies are very important to test the strength of the system. The analyses on level C contingencies, while not as probable, are somewhat of a stress test of the system and help identify weaknesses in the system. This is a vital test for timeframes other than real-time. Real-time and day-ahead analyses do not need to include any contingencies past N-1. As stated in the response to #1, the standard would benefit from distinct sections for the various timeframes.

Members Segments 1,4,5 Don Reichenbach			Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
South Carolina Elect & Gas Segments 1,3,5 Clay Young	X		SCE&G believes that a significant majority of the industry has used contingencies such as "Level C contingencies" in determining transmission performance in the past. Exclusion of these kinds of requirements will result in "decreased reliability" of the US transmission grid. SCE&G believes that these kinds of requirements should be retained in the NERC Standards. Also, same comments as submitted by the SERC Planning Standards Subcommittee. Response: This purpose of this standard is not to address system expansion issues – this standard's focus is on establishing limits. **The standard has been modified to clarify that credible multiple-element contingencies identified by an RRO must be studied. This would be applicable to all system operating limits.**
SPP Operating Reliability Group Segment 2 Endorsed by 5 Members, Segment 1 Scott Moore	X		However; credible, multiple contingencies such as bus faults, double-circuit tower outages, etc. should be examined to determine if system cascading, instability or uncontrolled separation could result as a consequence of such an occurrence. Response: The standard has been revised to reflect your suggestion.
WECC TSS Endorsed by 26 Members Segments 1,2,3,4 Chifong Thomas	X		The WECC TSS feels that these contingencies should be examined as is the current practice in WECC. However, this additional level of analysis can be implemented as a Regional Standard specific to WECC Response: The standard has been revised to reflect your suggestion.
OPPD Segment 1 John Mayhan	X		No Comment

Alberta Electric System Operator Segment 2	X		The AESO supports the comments made by to this point by the Standards Review Committee of the iSO/RTO Council *(There should be clear delineation of the time frame being reviewed and analyzed for multiple credible outages. The Planning arena and the real-time Operations expectations must be spelled out with specific measurements and non-compliance elements for each.)* Response: The standard has been revised to add more clarity to the time frames being addressed.

Pamela Mclean			• Level C contingencies are required within WECC, but that requirement can be handled by a regional difference. Response: WECC has submitted a Regional difference to address your second statement.
Allegheny Energy Supply Segment # 5 Ken Githens	X		Level C should be used in planning studies Response: The draft standard has been revised to clarify that this was intended to address all system operating limits, not just those used in the planning horizon.
Entergy Segment 1 Ed Davis	X		No Comment

3. NPCC has requested a Regional Difference in this section. Are there any other Regions who require a Difference, in light of the revisions to this section?

Summary Consideration: Several commenters indicated a preference for omitting Regional Differences that include requirements that are more stringent than the proposed standard. Omitting proposed Regional Differences is outside the scope of the SDT. The NERC Standards Process Manual indicates that Regions may request inclusion of Regional Differences that are more stringent as long as the regional differences:

- Are developed in fair and open process
- Do not have a significant adverse impact on commerce that is not necessary for reliability
- Provide an appropriate level of bulk system reliability
- Are based upon a justifiable difference between Regions or subregions

Commenter	Yes	No	Comment
WECC TSS Endorsed by 26 Members Segments 1,2,3,4 Chifong Thomas	X		**See end of this file. Response: It is within WECC's right to requesting a Regional difference. The drafting will continue to work with WECC to develop the Standard accordingly and put to ballot as appropriate.
BPA Transmission Segment 1 Mike Viles	X		WECC is requesting a "Regional Difference". See comments from WECC Technical Studies Subcommittee. Response: It is within WECC's right to requesting a Regional difference. The drafting team will continue to work with WECC to develop the Standard accordingly and put to ballot as appropriate.
Alberta Electric System Operator Segment 2 Pamela Mclean	X		The AESO supports the WEcomments made by to this point by the Standards Review Committee of the iSO/RTO Council One advantage of including Regional Differences even when they are more stringent than the (the rest of this comment was missing in the document submitted to NERC) Response: The SDT contacted the commenter and asked if she wanted to add to this comment, but the SDT did not receive a response.
Duke Power Segments 1, 5 Tom Pruitt	X		We believe there may be other regions with differences, but the current version is not clear enough to determine if more stringent requirements would be necessary in this region or others. Response: The drafting team appreciates your concern for clarity; however, the purpose of posting draft versions is to allow companies to request differences for evaluation and incorporation into the standard as it develops. Companies may elect to wait for an approved standard before asking for the addition of a Regional difference through the SAR process.

South Carolina Elect & Gas Segments 1,3,5 Clay Young	?		If these standards do not evolve to include "Level C" type contingencies, then SCE&G will ask SERC to review its recently retired "Planning Principles and Guides" to determine if they need to be revived. SERC recently retired these requirements because SERC determined that they were redundant to the NERC Planning Standards. They are not redundant to this reduced 603 standard. SERC will determine at that point if a SERC Regional Difference will be pursued. Also, same comments as submitted by the SERC Planning Standards Subcommittee. Response: The drafting team appreciates your concern for reviewing past Regional practices in light of this Standard's development; however, the purpose of posting draft versions is to allow companies to request differences for evaluation and incorporation into the developing standard. Companies may elect to wait for an approved standard before asking for the addition of a Regional difference through the SAR process or may simply apply more stringent rules within their Region.
Southern Co Services Segment 1 Marc Butts Southern Co Gen & Energy Marketing Segments 5,6 Roman Carter		X	We do not currently know of any Regional differences at this time. However, during the initial phasing in of standards, each region may find adopting or developing a different approach provides increased reliability. Therefore, we believe that differences should be considered as they are identified in the future. Response: The purpose of posting draft versions is to allow companies to request differences for evaluation and incorporation into the developing standard. Companies may elect to wait for an approved standard before asking for the addition of a Regional difference through the SAR process.
SPP Operating Reliability Group Segment 2 Endorsed by 5 Members, Segment 1 Scott Moore		X	But, we are not convinced that more restrictive regional differences should be incorporated into the standards. NERC standards are minimal criteria and regional differences for exceptions from the criteria are all that should be included, not additions to the criteria. Response: The NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: • Are developed in fair and open process • Do not have a significant adverse impact on commerce that is not necessary for reliability • Provide an appropriate level of bulk system reliability • Are based upon a justifiable difference between Regions or subregions
AEP Segment # 1,3,5,6		X	Despite the inclusion of NPCC's more stringent requirements applicable in NPCC, a regional difference at the NERC level should only be used to substitute a less stringent standard or a different standard to be applied for a particular Region. A region can always require its members

Paul Johnson			to perform to a level higher than the NERC minimum standards through Regional processes. Response: The NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: • Are developed in fair and open process • Do not have a significant adverse impact on commerce that is not necessary for reliability • Provide an appropriate level of bulk system reliability • Are based upon a justifiable difference between Regions or subregions
California ISO Segment 2 Ed Riley		X	While the CAISO feels that Regional differences are important, and should be supported by NERC, we do not feel that it is appropriate to include specific Regional differences within the framework of the Standards, but rather to include a more generic statement that NERC reconizes that there are Regional differences, and that NERC supports the Regions in enforcing the reliability requirements for such Regions as have identified Regional differences. NERC should specify minimum standards. Regions may have standards which are more stringent. Any variances from NERC Standards could be submitted to and supported by NERC. Response: The NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: • Are developed in fair and open process • Do not have a significant adverse impact on commerce that is not necessary for reliability • Provide an appropriate level of bulk system reliability • Are based upon a justifiable difference between Regions or subregions
ISO/RTO Council Segment 2 Endorsed by 7 IRC Members Bruce Balmat		X	While regional differences are important, and should be supported by NERC, it may not be appropriate to include specific Regional differences within the framework of the Standards. Rather, there should be a more generic statement that NERC recognizes that there are Regional differences, and that NERC supports the Regions in enforcing the reliability requirements for such Regions that have identified Regional differences. Regions may have Standards which are more stringent. Variances to NERC Standards would still be expected to be included in the NERC Standards. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: • Are developed in fair and open process • Do not have a significant adverse impact on commerce that is not necessary for reliability • Provide an appropriate level of bulk system reliability

			• Are based upon a justifiable difference between Regions or subregions
MAAC Segment 2 John Horakh		X	The changes suggested in 1. and 2. above are not intended to be a Regional Difference, they should apply to everyone. Response: The drafting team considers your comments for questions 1 and 2 as constructive criticism and not as a request for a MAAC Regional difference.
Manitoba Hydro Segment 1,3,5,6 Gerald Rheault & Ron Mazur			Manitoba Hydro believes that the MAPP Region develops its operating limits using a methodology consistent with Standard 603 with variation as defined in 2 above. We do not require a Regional Difference to plan and operate the regional interconnected network reliably if a statement addressing question 2 is added to the Standard. . The rationale NPCC has for its regional difference is not clear – the requirements should be consistent with the system design, but it is unclear what value is added in the calculation of limits from consideration of level D contingencies Manitoba Hydro does not possess adequate information to address the need for Regional Differences in other regions than MAPP. Response: If this Standard moves to ballot containing the NPCC difference, it will be NPCC's responsibility to provide the justification for the more stringent requirement and to show that it does not have a significant adverse impact on commerce that is not necessary for reliability. The SDT has asked the Regional Manager for NPCC to provide this justification so that it can be posted for the Ballot Pool to review when the standard is posted for review prior to ballot.
MidAmerican Segment 3 Tom Mielnik		X	No Comment
Midwest ISO Segment 2 Terry Bilke			We can't speak for other Regions.
NY State Reliability Council Segment 2 Alan Adamson		X	The NYSRC has adopted Reliability Rules that are more stringent and more detailed than Standard 600. The NYSRC Reliability Rules are not inconsistent with or less stringent than the NERC Reliability Standards, and the NYSRC has elected not to propose that they be made part of the NERC Standards. Response: Not requesting a Regional difference in this Standard is at NYSRC's discretion.
PJM Segment 2 Joe Willson		X	NPCC's request is for more stringent requirements which a region can always implement. The NERC standards must be for all. Response: The NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: • Are developed in fair and open process

			• Do not have a significant adverse impact on commerce that is not necessary for reliability • Provide an appropriate level of bulk system reliability • Are based upon a justifiable difference between Regions or subregions
Mirant Segment 6 Alan Johnson		X	No Comment
MAPP Segment 2 Endorsed by 8 Members Lloyd Linke		X	No Comment
NPPD Segment 1 Alan Boesch		X	No Comment.
NYISO Segment 2 Robert Waldele		X	No Comment.
SERC Segment 2 Susan Morris		X	No Comment
SERC Operations Planning SubC Segment 2 Endorsed by 8 Members Segments 1,4,5 Don Reichenbach		X	No Comment
SERC Planning Standards SubCommittee Segment 2 Endorsed by 7 Members Segment 1 Bob Jones		X	No Comment
TVA Mark Creech		X	(TVA agree with the SERC Planning Standard Subcommittee).

Allegheny Energy Supply Segment # 5 Ken Githens		X	No Comment
Allegheny Power Segment # 1 William J. Smith		X	No Comment
CenterPoint Energy Segment 1 Don Chandler		X	No Comment
FirstEnergy Segment 1 Ray Morella		X	No Comment
FRCC Segment 2 Endorsed by 10 FRCC Members Segments 1,3,4,5 Patti Metro		X	No Comment
NPCC CP9 Segment 2 Endorsed by 7 Members Guy Zito			N/A

4. The drafting team made every effort to respond to industry comments received during the first posting of this proposed standard. The standard was modified in response to these comments in many cases. If the team's response did not properly respond to your comment, please let us know in the space below.

Summary Consideration: The commenters agreed that the comments submitted earlier had been considered by the SDT.

Commenter	Comment
Ameren Segment # 1 Kirit Shah	As we have commented earlier, this standard includes too many items. We still believe and recommend that, particularly after "lessons learned" from August 14th blackout, Facility Ratings should be separated as a separate standard. Response: The standard was drafted consistent with the SAR. As the team responded before. During development of the SAR for this standard, it was decided by the industry that it would be appropriate if all requirements for facility ratings, System Operating Limits and Transfer Capability were part of the same standard. Additionally, there appears to be no apparent benefit to splitting the draft standard since each piece is a separate requirement within the draft standard.
California ISO Segment 2 Ed Riley	While we agree that the drafting team responded to industry comments, we believe that the August 14th Blackout Report might require additions or clarifications to items in this Standard. The CAISO feels that this should be considered in the decision to move forward with this Standard. Response: Since the comment didn't provide any specific suggestions or cite areas that may need added clarification, the drafting team can only provide a general response to this comment. The Drafting Team would appreciate more specific information. The drafting team believes the proposed standard thoroughly and adequately addresses the requirements of the SAR. If in the future it is determined that additions or clarifications are desired, there are process that facilitate that.
Duke Power Segments 1, 5 Tom Pruitt	The 603 section on regional differences that allows NPCC's alternative methodology speaks to transfer capability under normal and emergency conditions. It is unclear as to when each condition, normal or emergency, applies and how system operation would be affected. The titles Normal & Emergency "Transfer Capability" are in themselves confusing because the non-NPCC requirements don't use the term "Transfer Capability". What is the reason for the different nomenclature? All this once again points out that allowing for regional differences will create different market conditions that should be evaluated by a joint NAESB/NERC effort. i.e. A point to point reservation in NPCC may be denied because of an N-2 condition. A marketer normally operating in SERC would only expect to be denied for N-1 conditions. The bottom line is: The restrictiveness of each region's reliability standards will ultimately determine the openness of their market. There needs to be some level of consistency as to methods (which margins are applied and how are they applied). The effort to be non-prescriptive will result in gaming or the appearance of it. Response from NPCC: The NPCC system conditions specified under Normal and Emergency Transfer Capability are defined in the NPCC **A-2, "Basic Criteria for Design and Operation of Interconnected**

	Power Systems" sections 6.1 and 6.2**.** The entire A-2 document may be found at: http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf. NPCC has provided a whitepaper in support of its regional difference.
Entergy Segment 1 Ed Davis	The drafting team did develop responses to our comments and we agree with some of the responses and disagree with others. Response: The drafting team appreciates that you feel that we at least addressed all responses.
Florida Power & Light Segment 1 John Shaffer	A question on the use of outage transfer distribution factors was raised in comments to the 1st draft of the standard (see page 87 of comment_responses12-03). The response was "see response to earlier comment." No earlier response addressing this question could be found. In order to improve readability of the responses, it is suggested the responses be repeated where relevant rather than referring elsewhere in the document. Response: The drafting team will try to be more explicit in the reference to earlier comments or will repeat the response.
FRCC Segment 2 Endorsed by 10 FRCC Members Segments 1,3,4,5 Patti Metro	The drafting team did a very thorough job in reviewing and addressing the comments provided during the 1st posting. The explanation of the Compliance portion was very helpful, however in reviewing the standard there are still inconsistencies in the formatting of the Compliance Monitoring Process sections. The format used for Requirements 601, 603, and 605 should also be used for Requirements 602, 604, and 606. Specifically d2 and d3 in 602, 604, and 606 can be combined in the same format used for d1 in 601,603, and 605. The Applicability is more clearly defined than the previous standards posted for comment, however there continues to be confusion about the functions vs. entities in the functional model. Response: Agreed, combinations of the compliance requirements have been changed to address your observations.
Independent Electricity Market Segment 2 Khaqan Khan	Yes- the drafting team made efforts to provide response
MAAC Segment 2 John Horakh	The team's response was very good and complete. The team also did something logical in their response document by grouping the three questions related to each Section of the Standard. However, the team also renumbered the questions, so that original questions # 6, # 7, and # 8 from the comment form became a three part question # 6 in the response document, original questions # 9, # 10, and # 11 became a three part question # 7, etc. This was very confusing when searching for the response to a comment made to a particular original question. The numbering of questions should always be maintained to be that used in the original comment form. Response: This is a good observation. The drafting team will not repeat this mistake.

Manitoba Hydro Segment 1,3,5,6 Gerald Rheault & Ron Mazur	Manitoba Hydro's comments for the first posting of this Standard have been addressed.
Mirant Segment 6 Alan Johnson	The drafting team adequately addressed Mirant's comments. Thank you.
NYISO Segment 2 Robert Waldele	The drafting team still has not offered any evidence that monetary sanctions will be more effective at achieving compliance with this (or any other) standard. We are concerned that monetary sanctions may result in planning or operating entities doing a cost/benefit analysis of the "cost of compliance" vs. the benefit of "not getting caught." Response: The SDT and majority of the stakeholders support monetary sanctions for violations that could pose serious threats to reliability of the grid. Monetary sanctions have proven to be effective in other industries, such as the nuclear industry, and draw significant corporate, political, and public focus to comply. A graduating scale based on the number of violations and for repeated violations is a feature of the NERC sanction structure. This provides added incentives to comply. The Drafting Team also does not propose monetary sanctions for other violations, such as documentation of methodology, that are not expected to serious threaten reliability. This draft is no closer to respecting the reliability goals of the original Operating Policies. There is a lack of clarity, and references to multiple entities does not establish a hierarchy of command and control where the RA should have the ultimate responsibility. Response: Requirement 603 was revised to identify more specifically which entities are responsible for having and issuing their SOL Development Methodologies.
Reliant Energy Segment 5 Charles Yeung	In the first posting, Reliant submitted comments that raised concerns about the lack of consistent ATC calculations and methodologies. Reliant understands that the NERC DFR standard is focused on reliability (TTC) and commends the drafting team in adopting the industry comments received that called for the exclusion of ATC from a reliability standard due to its commercial nature. However, Reliant also understands that many entities do not believe NAESB should develop a business practice to standardize an ATC methodology due largely in part to the fact that ATC values are derived from many divergent methodologies that are based upon individual TSP and/or Regional reliability needs – particularly in the calculation of CBM. Reliant is a member and active participant in both the NERC and the NAESB organizations and is concerned a lack of standardization of methodologies will lead to inconsistent ATC values and affect both reliability and the markets. Reliant recalls correspondence from 2 NERC members to the NERC Board (4/17/02 Roy Thilly of WPPI and Dave McMillan of Calpine) that described the commercial nature of ATC and called for the removal of ATC methodologies from the existing NERC Planning Standards. In those letters, there was also recognition of the same concern Reliant raises now;

	that is in the February 2002 Board decision to adopt the revised NERC Planning Standards, NERC continued the possibility of each Region having its own methodology in calculating CBM. Those letters are attached to these comments. Since then, NAESB has been formed to develop commercial standards for the wholesale electric market and NERC has formed the Market Committee to continue NERC activities in the determination of market impacts of reliability standards. Because the DFR Standard removes the ATC and the associated CBM calculation from the reliability requirements, and NAESB has received recommendations that it should NOT pursue the development of standardized ATC business practices, the industry seems to be in a quandary on how to address the consistency of ATC and CBM calculations. The Market Committee should be asked to address the impact on the market of the proposed DFR Standard and provide a NERC position (with possible Board approval) of which standard setting organization should tackle the problem of ATC standard methodology. Response: The SDT appreciates your feedback and acknowledges the complexities of this subject. Comments from the industry received when the SAR was drafted overwhelmingly hold that issues related to ATC and CBM are outside the scope of this standard.
SERC Segment 2 Susan Morris	The drafting team responded as follows to the question regarding the NPCC proposed regional difference (draft 1 comments, question 3). Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: o Are developed in fair and open process o Do not have a significant adverse impact on commerce that is not necessary for reliability o Provide an appropriate level of bulk system reliability o Are based upon a justifiable difference between Regions or subregions The response above was listed nine times in the responses document for the first posting. Based on the comments to question 3 on the first posting, the drafting team response is inadequate. Due to the multiple views of the original intent of recognizing regional differences, the drafting team should forward the feedback to the appropriate entities in NERC to review this interpretation. More stringent requirements for a Region should be managed and determined by the Region's members, not all of North America. Response: The SDT acknowledges that there is significant disagreement on how regional differences should be addressed within a NERC standard versus the regional standards based on the number and content of the "No" responses to Question 3 (Q3) of the first posting. Your comments apply to the NERC standards process as a whole, and the SDT lacks the authority to change the NERC process. There is a SAR under development to revise the Standards Process Manual, and you are encouraged to submit your comments when that SAR is posted for comment.

SERC Operations Planning SubC Segment 2 Endorsed by 8 Members Segments 1,4,5 Don Reichenbach	Many of the SDT's responses relied on the Functional Model either in its current form or with the identified necessary changes. It is even stated that the Model is the "foundation" of the standard. It is not practical for the foundation of a standard to be based upon potential future changes to the Functional Model. Response: The SDT agrees. But a new standard may differ from the current version of the model for a number of reasons. Development of standards, guidelines, and procedures are dynamic processes. The range and diversity of experience and expertise varies between each SDT and the Functional Model Team and deserves to be captured by the model and standards. Since the standards will have more detail than the model, their development is expected to identify and resolve technical issues that may not have been considered in development of the model. Thus, the model cannot restrict the standards and may evolve as the standards are developed. The SDT must ensure the standard fits the current version of the model, or identify differences and ensure these are communicated to the Model Team. The SDT does agree that the NERC process must ensure proper coordination among the standards and the functional model development.
SERC Planning Standards SubCommittee Segment 2 Endorsed by 7 Members Segment 1 Bob Jones Southern Co Services Segment 1 Marc Butts Southern Co Gen & Energy Marketing Segments 5,6 Roman Carter TVA Mark Creech	In the drafting team's response to comments on Draft-1 they stated on numerous occasions that "the NERC requirement is intended as a minimum and regions have the right to use more stringent requirements if they choose." However, this intent is not stated anywhere in Standard 600. We feel strongly that this intent needs to be included in the document. The following should be added on page 1 of the standard to make it clear that it applies to the entire standard: "*The level of performance specified is a minimum and more stringent criteria for individual transmission providers or regions are permissible."* Many of the Transmission Providers in SERC plan beyond N-1 criteria. The majority of the PSS feels that adherence to 603 as written without this wording will result in reduced reliability in SERC. Response: The suggested addition is a statement that is not necessary. Entities are never precluded from adhering to more stringent processes than those that are required by NERC. This standard does not address system expansion. There is another SAR DT that is addressing transmission planning – please submit your comments to that SAR DT when their SAR is posted.
South Carolina Elect & Gas Segments 1,3,5 Clay Young	If these standards do not evolve to include "Level C" type contingencies, then these standards must include specific statements that Regions, sub-regions, and individual transmission providers may have more stringent standards to ensure that the current and expected level of transmission performance is continued. Also, same comments as submitted by the SERC Planning Standards Subcommittee.

	Response: The system operator must know the status of the system following the next event – for those events that are credible multiple element contingencies as identified by the RRO.
SPP Operating Reliability Group Segment 2 Endorsed by 5 Members, Segment 1 Scott Moore	In our previous comments regarding sanctions for lack of methodology, we indicated that lacking a methodology or having an inaccurate methodology was just as serious an issue as not having an established rating. The SDT responded that this was a judgment call and that the majority of commenters had not concurred with our position. We still have concerns about this issue and would ask that the SDT reconsider its position. The SDT states that the lack of a methodology is not a reliability issue, but we believe it is. Maintaining a reliable system is contingent upon having accurate facility ratings. If the ratings are not accurate or are developed without a sound basis, then there is most definitely a reliability issue that needs to be addressed. Response: The SDT agrees having a documented methodology is important and does impact reliability. However, the simple lack of required 'paperwork' does not have a direct and immediate impact upon real-time operations. The unavailability of the values will have an immediate and detrimental impact upon real-time operations. In their response to our previous comment on the requirement in 606(a)(1), the SDT indicated that the Planning Authority is responsible for long-term transfer capabilities and the Reliability Authority is responsible for real-time transfer capabilities. We concur with this conclusion. In order to prevent confusion we suggest the SDT incorporate this time horizon into 606(a)(1) and 605(a)(1) as the SDT did in 606(e)(2) and 606(e)(4). Response: The SDT concurs and has incorporated changes to address this concern.
WECC TSS Endorsed by 26 Members Segments 1,2,3,4 Chifong Thomas	The WECC TSS believes that all of its previous comments were adequately addressed.

5. Do you agree with that Planning Authorities and Transmission Planners play a role in the development of System Operating Limits?

Summary Consideration: Most commenters agreed with the SDT that Planning Authorities and Transmission Planners play a role in the development of system operating limits. Several commenters suggested that all limits should be developed using a single methodology established by the RA. Because the Planning Authority Area is not required to be the same size as the Reliability Authority Area, requiring that both entities use the same methodology may be impractical. Each of these Authorities may operate in multiple Regions, and may be required to have methodologies that address specific regional concerns.

Commenter	Yes	No	Comment
Independent Electricity Market Segment 2 Khaqan Khan		X	While the IMO recognizes that in some jurisdictions, the Planning Authorities, the Transmission Planners and Transmission Operator play a role in the development of SOL (and also IROL). It must be clear and unambiguously identified in this set of Standards that only one function i.e., the Reliability Authority is responsible for the final product. Emphasis: The RA should be responsible for the SOLs that are used in real-time operation and for near-term operation. Without a single entity being responsible for the development of "limits" it is entirely conceivable that the results of various studies required for the development of SOL (and IROLs) may not reflect current system configuration. Hence there is a risk of incomplete or incorrect limit coverage. Additionally, the use of a single entity ensures a more consistent application of the development methodology, the distribution of limits and lastly, application of the limits being assessed in both the planning and real-time periods. Since IROLs (which are a subset of SOLs) are the responsibility of the RA to identify, monitor, analyze and take actions on (Standard 201, 202, 203 and 204) it is the IMO's position that this responsibility to ensure System Operating Limits are derived should rest with the RA. The above comments are also applicable to 603 (a) and 604 (a). This thought process is consistent with Requirement 1 and the associated Principles (Requirements for establishing and Communicating Limits) contained in the OLD-TF Report accepted by NERC:OC in March of 2003. Additionally some of the comments NERC received in the balloting of Standard 200 indicate concerns over lack of coordination. In one submission, it was stated "There must be an express provision stating that Reliability Authorities have authority over all entities with facilities or operating within the RA's footprint" (PSEG). In this case the reference was to prevent instances of exceeding an IROL but the principle should be equally applied to the Derivation and Identification of the SOL (and hence IROL). Response: Ideally, the methodology used by the Reliability Authority and the Planning

			Authority should be the same so that the development of SOL's would be the same. In that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
NYISO Segment 2 Robert Waldele		X	The references to day-ahead as a "planning" study to be performed by planners confuses the concept of operating studies: day-ahead and real-time assessment of system operating limits should be performed using the same criteria/methodology by the same personnel. Further, it is not clear what the "longer term" horizon is (weeks?, months?) and Transmission Planners and Planning Authorities should be cognizant of the methodologies used in the development of System Operating Limits, but the determination of operating limits should be the responsibility of the operations engineering/security analysis staff of the Reliability Coordinator. Response: The standard has been modified to state more clearly that the RA is responsible for developing SOLs that are used in the operations horizon, and the PA is responsible for developing SOLs that are used in the planning horizon.
Southern Co Gen & Energy Marketing Segments 5,6 Roman Carter	X		From a Generating plant perspective, we heavily rely upon the Planning Authorities and Transmission Planners to identify appropriate system operating limits during the performance of studies related to *planned* changes in the transmission system. The addition of transmission equipment (such as capacitors or reactors), interconnection of new generation, replacement of generator excitation systems, addition of power system stabilizers, changes in voltage schedules, and other changes can have significant impacts on generators and the generator substation equipment. These changes can affect existing System Operating Limits and create the need for new ones that are not only important for the integrity and reliability of the transmission system, but for generator / transmission interconnections as well. Failure to address this during the *planning* process could result in loss or instability of several generators at a point on the grid and could have significant impact on the reliability of an area of the interconnected grid. Response: This standard does not address the planning process but does require the establishment of a methodology that Planning Authorities and Transmission Planners must use in developing the SOLs used in developing plans.
Ameren Segment # 1 Kirit Shah	X		Does Operation Planning falls under Planning Authority? Response: Operation Planning is short range planning/analysis, therefore it would fall under the Reliability Authority.
AEP Segment # 1,3,5,6 Paul Johnson	X		Planning Authorities and transmission planners would/should have the responsibility to determine the SOLs for time periods beyond the responsibility of the Reliability Authorities. The SOLs determined by the planning functions would be inputs for the RA to determine the real-time SOLs for the current system conditions

			Response: The SDT agrees.
ISO/RTO Council Segment 2 Endorsed by 7 IRC Members Bruce Balmat	X		While we recognize that in some jurisdictions, the Planning Authorities, the Transmission Planners and Transmission Operators play a role in the development of SOL (and also IROL), it must be clear and unambiguously identified in this set of Standards which function (authority) is responsible for development of the final product (limits, security ratings or transfer capabilities). Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. In that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
Peter Burke American Transmission Company Segment # 1	X		I agree that they may play a role in the development of System Operating Limits, but I would strongly suggest that only one entity establish the limits. I would suggest that the Transmission Operator establish the limits for the area under its control. Most of the System Operating Limits are going to be determined using the Facility Ratings Methodology. The Transmission Operators are closer to the area and in many cases more familiar with the area. They have the ability to use that knowledge to address real-time concerns in cases were a System Operating Limit might need to be updated to accommodate real-time system conditions. The Reliability Authority also has a role to play in the development of SOL's but, in many cases, differences within a Reliability Authority's footprint may lead to many System Operating Limit methodologies. Although it is the Reliability Authority function to direct action to maintain the system under its area within SOL's, it should not also be given the role as the ultimate SOL decider. Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. In that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
California ISO Segment 2 Ed Riley	X		The CISO believes that in some jurisdictions, the Planning Authorities, the Transmission Planners and Transmission Operators contribute to the development of SOL (and also IROL), the standard must be clearly identify which function (authority) is responsible for development of the final product (limits, securitly ratings or transfer capabilities). Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. If that is not the case, then the Reliability Authority would have ultimate responsibility in the

			development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
MidAmerican Segment 3 Tom Mielnik	X		In today's open access environment, Planning Authorities and Transmission Planners must use the same study criteria and methodology in planning the system as the Reliability Authority and Transmission Operators use in operating the system. Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. In that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
CenterPoint Energy Segment 1 Don Chandler	X		See comments to question 1 as an example. The system should be operated the way it is designed (i.e., planned) to operate. Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. If that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
Duke Power Segments 1, 5 Tom Pruitt	X		Generation owners/operators may also play a role in setting these limits (see example in comments to 6 below). **Response: Agreed.**
MAAC Segment 2 John Horakh	X		The PA and TP should have a limited role in developing SOLs. The SOLs they may develop should be used mainly to determine the difference in SOLs that occurs when certain facilities are placed in service. Planning SOLs should not be compared directly (number for number) to current operational SOLs Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. In that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
MAPP Segment 2 Endorsed by 8 Members	X		Planning Authorities and Transmission Planners should be coordinating their system additions with the people who develop operating guides Response: The SDT agrees.

Lloyd Linke			
Manitoba Hydro Segment 1,3,5,6 Gerald Rheault & Ron Mazur	X		Manitoba Hydro believes that the Planning Authorities and Transmission Planners play a role in the development of system operating limits(SOL)s. However there is a disconnect in the methodology to establish the planning and operating SOLs for system intact conditions. The planners use level C contingencies to establish planning level SOLs. The operators use level B contingencies and would check level C for cascading, instability and uncontrolled separation to establish their SOLs. As written in this Standard, it could be said that there is no reason to plan beyond the same criteria for transfer capability purposes. The group developing the planning standard may have to address this issue and this standard, in turn, may have to be re-examined. Planning time frame SOLs developed using the methodology in this Standard should be safe since level C contingencies would be checked for cascading, stability, and uncontrolled separation. In the operating time frame, for a rare fully system intact situation, there would be an inconsistency in that the operating limits would be higher than the planning limits which were developed with full consideration of category C contingencies. For this situation should these limits be dropped for system intact conditions to respect category C or should the operators be allowed to take advantage of the fat in the system intact situation Response: Ideally, the methodology used by the Reliability Authority and the Planning Authority should be the same so that the development of SOL's would be the same. In that is not the case, then the Reliability Authority would have ultimate responsibility in the development of SOL's for real-time system conditions and short term planning periods. The Planning Authority would be responsible for long term planning periods.
Mirant Segment 6 Alan Johnson	X		These functions play a role in that they provide information that the RA may use in the setting of SOLs.
NPCC CP9 Segment 2 Endorsed by 7 Members Guy Zito	X		Yes, however we believe the System Operating Limits and the role planners might play are more "near term" or "day ahead" in nature or a planning horizon. We would also stress that the ultimate responsibility for the SOLs resides with the Reliability Authority. Response: The SDT agrees.
Reliant Energy Segment 5 Charles Yeung	X		Yes, in fact, the 1-20-04 NERC Recommendation # 14 in response to the August 14 Blackout states: "The Planning Committee within two years shall reevaluate system design, and study criteria, methods and practices, to reevaluate transmission facility ratings methods and practices, and to recommend revisions."

SERC Segment 2 Susan Morris SERC Operations Planning SubC Segment 2 Endorsed by 8 Members Segments 1,4,5 Don Reichenbach Southern Co Services Segment 1 Marc Butts	X		Operating timeframe: Planning must be involved, particularly for stability analyses, given the state of current real-time analyses tools. Although the industry must work towards better online tools for stabiltiy analyses, currently most, if not all, entities rely on planning to perform stability studies. Planning/study timeframe: Planners are necessary for developing SOLs for the study timeframe since SOLs are based not only on the physical characteristics of equipment, but the status and configuration of the system. Response: The SDT agrees.
SPP Operating Reliability Group Segment 2 Endorsed by 5 Members, Segment 1 Scott Moore	X		One would be hard pressed to find a reason to justify responding negatively to this question.
TVA Mark Creech	X		(TVA agrees with the SERC Planning Standard Subcommittee).
BPA Transmission Segment 1 Mike Viles	X		No Comment
Entergy Segment 1 Ed Davis	X		No Comment
FirstEnergy Segment 1 Ray Morella	X		No Comment
Florida Power & Light Segment 1 John Shaffer	X		No Comment
FRCC Segment 2	X		No Comment

Endorsed by 10 FRCC Members Segments 1,3,4,5 Patti Metro			
Midwest ISO Segment 2 Terry Bilke	X		No Comment
NPPD Segment 1 Alan Boesch	X		No Comment.
NY State Reliability Council Segment 2 Alan Adamson	X		No Comment
OPPD Segment 1 John Mayhan	X		No Comment
PJM Segment 2 Joe Willson	X		No Comment.
SERC Planning Standards SubCommittee Segment 2 Endorsed by 7 Members Segment 1 Bob Jones	X		No Comments
South Carolina Elect & Gas Segments 1,3,5 Clay Young	X		No Comments
WECC TSS Endorsed by 26 Members Segments 1,2,3,4 Chifong Thomas	X		No comments
Allegheny Energy Supply Segment # 5	X		No Comment

Ken Githens			
Allegheny Power Segment # 1 William J. Smith	X		No Comment

6. Please enter any other comments you have regarding this standard in the space below.

Commenter	Comment
Allegheny Power Segment # 1 William J. Smith	Section 604(b)(2) does not seem to recognize that most System Operating Limits that are supplied in real-time. Limits typically vary with ambient temperature or coincident with system changes but the timing of these events is not predictable. This section infers that System operating Limits are delivered on a schedule. Response: Standard 604 (b)(2) does not preclude ambient condition derived SOLs. The 'schedule' for delivery of the required SOLs would be 'real-time' if appropriate for the users of these data. However, Standard 604(b)(2) must also cover operating time periods (e.g., seasonal operating limits) of up to one year, for which a schedule would be appropriate.
AEP Segment # 1,3,5,6 Paul Johnson	The term 'some' is not appropriate to use in the levels of non-compliance in for standards 602, 604, and 606. Whether one entity supplied 2% of the information or 99% of the information, they will be only Level 1 non-compliant. Only when 100% of the values are not provided is the level of non-compliance a level 4. To remedy, delete Levels 1 and 2 of non-compliance for each of these standards. Change the Level 4 to the following ""Not all Facilities Ratings (or SOLs or TC; as appropriate) were provided…………." Response – Based upon comments received, the industry does not appear to support your position, so the suggested change was not made. Standard 606(a)1 requirement 1 is not clear who has the ultimate authority, the PA or the RA. The standard needs to be very clear. I suggest the following: " The Planning Authority in coordination with the reliability authority shall establish and provide……" Response: - The standard has been revised to add clarity in response to this and other comments. The intent of the current language was that the RA would determine the Transfer Capability for the "operating horizon" and the PA would determine the transfer capability for the "planning horizon".
Peter Burke American Transmission Company Segment # 1	601(e)(4) Add the statement: "…Planning Authority for the areas in which the facilities are located within…" Response: The standard already implicitly requires this by requiring that all facility ratings be respected. 602(a)(1) What about jointly owned facilities? Since an entity will be non-compliant if they do not follow their methodology what should be done for jointly owned facilities. Response: - Refer to 601(a)1 which requires the Rating Methodology to include the rating of jointly owned facilities. The standard requires that a facility's rating be based upon the lowest component equipment comprising the facility. This is also required for jointly owned facilities. 602(a)(2)

	In the Functional Model the Transmission Owner (TO) has to provide ratings information to everyone listed in this standard but they also have to supply it to Transmission Service Providers (TSP). Which document should we use and if we use both than if I do not supply it to a Transmission Service Provider do I become non-compliant under this standard? Response: - No. If this Standard is approved by the ballot body and the NERC BOT, the Standard would be the 'controlling' document and the functional Model would be changed to recognize the requirements of the then existing standard. The SDT encourages participation in commenting on the Functional Model during the FM comment period. This standard is written on the basis that the TSP will make use of limits and transfer capabilities in performing its function and does not need the facility ratings information. 602(b)(2) The way this measure is worded the TO would have to provide Facility Ratings on a schedule determined by entities other than themselves. This should be reworded to say: "…on a agreed upon schedule between the TO or Generator Owner (GO) with the RA, PA, Transmission Planner (TP), TSP and Transmission Operator." Response: The premise of the standard is that the involved parties will develop the schedule jointly. However, in cases where a schedule cannot be mutually agreed upon, the needs of the user of the Facility rating values must determine the timing for the exchange of data. It is not feasible to develop a 'universal' schedule that will meet the needs of all the parties subject to this standard. This approach seems to be supported by most commenters. 602(d)(2) The word "randomly" should be removed. How would a Compliance Monitor (CM) ensure that the facilities have been selected randomly? Response: - Agreed; change will be made as suggested. 602(d)(3) What does the Standard Draft Team (SDT) mean by the words "impacted party"? This could be interpreted to mean a market impact. These standards are being develop to insure reliability not market availability. Response: - The words "impacted party" were removed, consistent with other NERC standards. 602(e)(1) I'm troubled by the word requested. Nowhere in the requirements was a TO or GO required to provided requested ratings. The requirements are that a TO or GO first establishes, update as required then provide but nothing is mentioned about request for rating. If the word requested is to remain than they need to make it clear on who's request a TO or GO has to honor. Though they list RA, PA, TP and Transmission Operator they don't make a distinction between associated and non-associated RA, PA, TP and Transmission Operators. This could lead to a noncompliance issue if a non-associated RA request ratings from a

	TO or GO and it is not provided. Response: - The schedule for data exchange required in 602(b)(2) is considered to be the same as a request. Overall Problems with 603. This standard fails to determine which entity is responsible for developing a methodology. In the Functional Model it seems that the Transmission Operator is the main entity responsible for determining SOLs. Response: - The standard requires that the identified entities document the methodology they use to fulfill their obligations under the functional model. The standard is ambivalent as to who develops the methodology, provided it is documented and applied. If/When this (or any) standard is approved by the ballot body and the NERC BOT, the then existing standard would be the controlling document. 603(c)(1) The word “the” needs to be added to the following statement: “…for “the” following…” Response: - Agreed; thank you 605(b)(1) In the requirements section the RA and PA need to document the methodology used so why would they need to make it available to themselves? Response: - Some minor adjustments have been made to add more clarity. The RA and PA need to share their methodologies with other RAs and PAs. 605(e)(4) If the RA and PA have to document the methodology why would they need to request a copy of the methodology? Response: Some minor adjustments have been made to add more clarity. The RA and PA need to share their methodologies with other RAs and PAs. 606(b)(1)&(2) They need to remove the word “responsible entities” and replace it with a list of the responsible entities. Response: The use of the term “responsible entities” is to avoid having to repeat the names of all the entities in every requirement. The entities are listed in the requirement in each case. This approach is consistent with other NERC standards.
BPA Transmission	Definition comments:

Segment 1 Mike Viles	Definition of Cascading outages does not match the existing definition that was laboriously reviewed within NERC (the last sentence of the old definition was not included here). The widespread component of cascading in the original definition is important – some local cascading could be acceptable and must be preserved. Response: The definition of cascading outages, has been modified, but not as suggested, to partially address industry concerns. The preponderance of industry comments received on the same definition posted with Standard 200 indicates that there is no common understanding of what is meant by the term, 'widespread'. This definition will continue to be modified as a result of industry comments until a definition has been developed that meets industry consensus. The definition has been revised to add a phrase to indicate that the incident is 'unplanned'. "The uncontrolled and unplanned successive loss of system elements triggered by an incident at any location. " 1. The Facility Rating definition includes another term "applicable rating" that corresponds to a single piece of equipment. However there is a separate definition for Equipment Rating. Are Equipment Rating and applicable rating one and the same? Response: - They are the same. Applicable rating refers to the conditions under which the rating will be applied (ie, the time duration of the rating, system conditions under which the rating will be applied, etc.) The definition has been slightly modified to add clarity. 2. Since the term Transfer Capability as defined is not used in the Western Interconnection it would be helpful for more information explaining how the transfer capability is used in the Eastern Interconnection. The Western Interconnection uses the term Operating Transfer Capability that fits the definition for System Operating Limit. We suggest providing an example of a Transfer Capability and how it may relate to System Operating Limits in a technical reference for this standard. Response: Examples cannot be included in the standard itself, but an explanation of the relationship between SOLs and Transfer capability can certainly be included in a reference document to accompany the standard. The NERC "Transfer Capability" document contains some excellent examples. 3. The standard needs a definition for the occurrence period referred to in the compliance section. Response: The Director-Compliance provided the following definition of the 'occurrence period' that appears as a heading in the Sanctions Table that was attached to the draft standard. "Occurrence Period - The time period in which performance is measured and evaluated." Section 601.a.2: Refers to applicable ratings, not equipment ratings. We suggest that "applicable ratings" be changed to "applicable equipment ratings" to be consistent with the "equipment rating" definition. Response: - Agreed. This change has been made. Section 601.d.3, second sentence: Please clarify what "data" needs to be kept.

	Response: - Data would include all information acquired to substantiate or related to the non-compliance in question. A list of documents that would need to be made available to the Compliance Monitor has been added to the standard. Sections 601.e.1, 601.e.2.i, and 601.e.3.i: Replace the word “item” with “applicable equipment types”. This eliminates the mixing of items and equipment types in section 601.e. Response: - The use of the term item was intended to apply to the assumptions made as opposed to the equipment types. This has been modified to add clarity Sections 602.b.1 and 602.b.2: Replace the term “Responsible entities” with “The Transmission Owner and Generator Owner” to be consistent with terms used in Section 602.a. Response: The use of the term “responsible entities” is to avoid having to repeat the names of all the entities in every requirement. The entities are listed in the requirement in each case. This approach is consistent with other NERC standards. Section 602.b.2, third line: Add “associated “ before “Reliability Authority “ to clarify that the Facility Ratings do not need to be provided to entities that do not need them. Response: - Agreed, clarity is added by this change. Section 603.a.3.i.A: In the second sentence replace “pre-contingency thermal and voltage limits” with “applicable facility ratings”. The steady-state condition may follow a contingency so a pre-contingency limit may not be applicable. Not all facility ratings are based on thermal or voltage limits. For example series capacitors can be current limited due to dielectric limits. Response: - Agreed, clarity is added by this change Remove the last sentence. In real-time operations the pre-contingency condition could follow a contingency and it may be necessary to curtail load or transfers to maintain the system within the System Operating Limits. Response: - Agreed. This change has been made. Section 603.a.3.i.B: Replace “steady-state” with “system “. The term steady-state exists pre-contingency and post-contingency and can be confusing when it is only used in the pre-contingency discussion. Also replace “maintenance” with “outages that may impact System Operating Limits during the period of the planning study”. The planned outages may be related to construction, or equipment failures in addition to maintenance. Not all outages will have an impact on System Operating Limits and this allows some flexibility in determining which outages need to be included in the planning study. Response: - Agreed, clarity is added by this change.

	Section 603.a.3.i.C: Replace “steady-state” with “system”. The term steady state exists pre-contingency and post-contingency and can be confusing when it is only used in the pre-contingency discussion. Response: - Agreed, clarity is added by this change. Section 603.a.3.ii.A.a: Revise to read as “Loss of any facility with single line to ground or 3-phase fault (whichever is more severe) with Normal Clearing. This clarifies that the faulted facility is permanently lost. Response: - Agreed. Modifications were made to add clarity. Section 603.a.3.iii: The “planned system” needs clarification since there are future planning studies and there are near term operational studies that include planned outages for construction and maintenance. Response: - The standard was modified to clarify what was intended by the planned system. Section 603.a.3.iii.A.a: Suggest replacing the sentence with: All facilities are operating within their applicable facility ratings. Response: - Agreed. This change has been made to add clarity. Section 603.a.3.iv: We are not sure what the term “Subsequent Contingency” means? The only difference between the response for the planned system (Section 603.a.3.iii) and this section is the option to interupt load in response to the contingency. This difference is consistent with the difference between planning studies and operational studies but the term “subsequent contingency” implies closely following the previous contingency which also implies there may not be time for system readjustment. Is that what is intended? If it is, it needs to be clarified. Response: - The standard was modified to clarify what was intended by the phrase, ‘subsequent contingency’. Section 603.a.3.iv.A.a: Suggest that “post-contingency thermal, frequency and voltage limits” be changed to “facility ratings”. Response: - Agreed, change adds clarity. Section 603.a.4.v: Refers to Sections that do not exist. It looks like it should be Sections 603a.4.i-iv. Response: This correction has been made. Thank you for pointing this out. Section 603.c.1, second sentence: Add “the” preceding “following”. Response: - This correction has been made.

	Section 604: Does the Balancing Authority need to be included in this section to receive System Operating Limits applicable to scheduled paths? Response: - No, the balancing authority does not require such information. Section 605.a.3.v**:** Include 605.a.3.i-iv not just 605.a.3.i. Response: - Agreed. This section has been changed in a way that supports your suggestion.
California ISO Segment 2 Ed Riley	1) Section 603, (a), (3), (i), A): The fourth sentence is confusing when it refers to "curtailment of transfers is not required to maintain the system within the System Operating Limits." If there is loop flow, etc. on the system, curtailment of transfers would be utilized. Response: This sentence has been removed in response to this and other comments. 2) Section 603, (a), (3), (ii), A), (c.): The CAISO recommends the use of monopole and bipole. Response: - The language used in the standard is that previously approved in the NERC planning standards. Since this is the only comment received to make the change, it has not been incorporated. 3) Section 603, (a), (3), (iii), A, (e.): The CAISO recommends adding a new letter with the following: "Reactive margin criteria is satisfied if appropriate for the system." Response: - Reactive margin is included in item d “the system demonstrates transient, dynamic and voltage stability”; therefore no change was made. 4) Section 603, (a), (3), (iii), A), (g.): The CAISO recommends modifying this section to include "next single contingency". Also, one of the system adjustments could be the cutting in a SPS/RAS. Response: - “single” will be added, as suggested. 5) Section 603, (a), (3), (iv), A), (after d.): The CAISO recommends adding a new letter with the following: "Reactive margin criteria is satisfied if appropriate for the system." Response: - Reactive margin is included in item d “the system demonstrates transient, dynamic and voltage stability”; therefore no change was made.

	6) Section 603, (a), (3), (iv), A), (f.): This is a relaxation of the criteria to allow for interruption of load for a single contingency. The CAISO does not believe we should allow this for the bulk transmission. Response: - The standard has been changed to clarify what was intended. There has been no relaxation of existing criteria. 7) Section 603, (a), (3), (iv), A), (g.): Probably should modify to include "next single contingency". One of the system adjustments could be the cutting in a SPS/RAS. Again, this is a relaxation of the criteria to allow for interruption of load for a singel contingency. The CAISO does not believe we should allow this for the bulk transmission Response: - The requested change has been made. 8) The CAISO feels that the term "Cascading Outage" as currently written is not adequate, or, more specifically, is too broad; Response: - The definition has been modified to add more clarity in response to this and other comments. 9.) The term "local network" is not defined. The CAISO's recommends, based on previous experiences in attempting to define this term, that the Standard Drafting Team consider replacing this term with the more generally defined, and accepted term "radial". Response: - This term is difficult to univerisally define. It has been removed from the referenced text and the sentence rewritten to add clarity. 10.) The CISO has been involved in the IRC's SRC review process and agrees with the comments submitted jointly by the SRC. Response: - The IRC's comments have been responded to elsewhere in this document.
Duke Power Segments 1, 5 Tom Pruitt	a. There is some confusion between what constitutes a facility rating versus an operating limit in some cases, such as generator reactive capability and Nuclear Switchyard voltage Limits. • The reactive capability or rating of a generator is typically considered to be the limit based on the machine D curve or capability curve. However, the generator bus voltage or auxiliary bus voltage may limit the reactive capability of a particular generator for certain system or operating conditions. Unless the reactive limit in VARs is a single value (which it usually is not), this is normally referred to as an operating limit. However, classifying such a limit as the reactive power “facility rating” for the generator seems to be what this standard requires. Is

this true? The standard seems open for interpretation on this point, so shouldn't this be clarified?

Response: A Facility Rating is applicable for a defined set of conditions. Your interpretation is consistent with the intent of the standard.

- It's not clear if items such as Nuclear Switchyard Voltage operating limits should be documented as a "Facility Rating", which the generator would specify and section 603 requires the TO to not violate. Another question is how should potential changes to these limits be facilitated?

  Assuming the nuclear switchyard voltage limits would be specified as a Facility Rating, should this standard require the TO to notify the nuclear operators if their contingency studies indicate the voltage could be degraded below the required minimums under certain contingencies so the plants may evaluate if they must take some compensatory actions, such as entering a Tech Spec required Limiting Condition for Operations, etc?

Response: Maintenance of customer-driven acceptable voltage levels is not considered a system reliability issue and is not addressed in this standard. These issues should be addressed in the interconnection agreement between the customer and those responsible for the transmission system. Contracts between these parties can be more restrictive or stringent than the requirements of this standard.

b) Section 601 and 602 - A generation owner/operator will not necessarily know which of their equipment ratings are significant to grid reliability and we would not want to develop a methodology and associated rating documentation for the rating of every piece of plant equipment. Should this standard either specify, or require the associated RA, PA, TP/TO to specify, what generation ratings are significant to their studies and thus must be documented?

Response: - The owner of the equipment will be requested to provide ratings as needed by the user. The standard does not dictate this information, as it can vary.

c) We are concerned that the standard as written may not reflect the latest revision of the Functional Model. In the "Applicability" section, it references a specific version of the functional model - probably should reference the *current* version of the functional model (FM) since it will likely change.

Response: the Functional Model continues to be under review. If this standard is approved by the ballot body and the NERC Board the functional model will have to be modified accordingly.

d) How does one map between the entities in the FM (authorities) to the current state entities (control areas, etc). If the standard applies to the existing entities but the standard references FM entities, we will all get confused in attempting to implement this standard – this problem needs to be addressed for all standards.

Response: - The transition from a control area model to the functional model is beyond this standard alone and is an effort that NERC is still mapping out.

e) Section 605.a.3.v has a generic statement about applying "reliability margins" to the calculation of transfer capability. This statement is too nebulous and will allow for all kinds of inconsistency as to how/what margins are applied. This effort to be non-prescriptive will result in gaming of markets or at least the appearance that it is occurring.

Response: - This section in the Standard specifies that the RA and the PA provides a description of how the

	methodology used would address relaibility margin ahead of time. This requirement would make it difficult to game the system. Further, since these transfer capabilities are reliability based and not commercial (ATC, CBM, or TRM), there does not appear to be an opportunity for gaming. f) Does this standard have any dependencies to other standards? Do other standards have to be in place before this one could be implemented? For example, in sections 605/606 - How are these transfer limits posted for implementation? How are these limits implemented in the real time and changed based on current system? The answer will be in the Operate Within Limits Standard (200) - clearly a dependencies description is important for these standards. Response: This standard does have relationships with the Coordinate Operations, Transmission Planning and Operate Within IROL standards, for example. The NERC BOT will be asked to adopt an implementation schedule if this standard is approved. When the standard is balloted, the implementation plan will also be posted so the industry can vote with full knowledge of how the standard will be implemented.
Florida Power & Light Segment 1 John Shaffer	603 The Requirement 603 (a) (3) (ii) should be modified as shown below to make it clear the analysis and/or simulations may not be needed for Contingency 603 (a) (3) (ii) A) (a) (i.e. normally cleared three phase faults). A) The following single contingencies must be ~~evaluated~~ assessed. The word assessment is defined in the NERC Planning Standards to make it clear that simulation studies may not be required. In Regions that do not have significant problems with normally cleared three phase faults, the need to conduct dynamic simulations of these faults can be assessed based on periodic stability studies. While most Reliability Authorities have power flow computation tools to permit rapid and large scale simulation of single contingency outages, a similar capability for dynamic simulation of faults is neither common place nor necessary in many Regions. Response: There appears to be little difference between evaluated and assessed. This is the only comment received on this issue. The change has not been made. 603 It appears that requirement 603 (a) (3) (iv) is intended to require that operational studies evaluate single contingency outages that are followed by system readjustments and then another single contingency outage. This is reasonable for real time contingency analysis and may be needed on a day ahead basis for a few select contingency pairs. The problem is this requirement language could be interpreted to mean all possible N-1 outages followed by system readjustments and then any other N-1 outage for all operating time horizons. The level of calculations need to support such an interpretation is neither practicable nor useful. It is recommended 603 (a) (3) (iv) be changed as follows: (iv) Response to Subsequent Contingencies for key System Operating Limits (operations studies only): Response: It is not the intent of this standard to impose unrealistic or impractical requirements upon those who must comply merely to find noncompliance. The standard is based upon pre-existing planning standards that have been field-tested in the NERC compliance program. The methodology required in this standard must spell out the manner in which operational studies are carried out. Portions of requirement 603 have been re-written in response to this and other comments.

	604 It is not clear in the language of 604 that the term "schedule" means both when and what. Transmission operators should have the flexibility to request different levels of SOL detail for different time horizons. A Transmission Operator may want to see all SOLs for real time but only selected relevant SOLs for a week ahead time horizon. Response: - The standard allows those involved to determine their own schedules for data exchange within their time horizons because it is not practical to develop a universal schedule that will fit the needs of all parties. In your example, the TOP could ask for all SOLs real time and just a few a week ahead under the standard. 605 Requirement 605 (a) (2) could be interpreted to exclude the use of transfer distribution factor cutoffs for ignoring overloads that have a very low sensitivity to transfer The allowed use of TDF cutoff factors (as described in NERC reference Document: Transmission Transfer Capability – May 1995) should be explicitly identified. Response: - The distribution factor cutoff should be a consideration and should be incorporated into the transfer capability determination methodology if used. If added to the standard, this would be just one of many elements that may be included in a methodology, however the standard is not going to specify these.
FRCC Segment 2 Endorsed by 10 FRCC Members Segments 1,3,4,5 Patti Metro	The Purpose statement should be changed from "To determine Facility Ratings, System…." To "To determine and communicate Facility Ratings, System…." Response: - valid observation, change added. The Applicability statement references Version 2 of NERC's functional model. We suggest you leave out any reference to the Version of the model. If a new version is approved, would this standard then need to be revised? The proposed Functional Model Working Group has the responsibility to review and model revisions so that they do not conflict with existing standards, so we do not think reference to the version is a good idea. Response: - Valid Observation, change added. <u>Specific comments on Requirement 601</u> Requirement 601(a)(3) seems a little confusing. We believe we understand the intent, however we think rewording would provide more clarification. We would suggest rewording the paragraph to something like this : "The methodology in 601(a)(1) shall identify the assumptions used to determine Facility Ratings and the method by which ratings of major bulk electric system equipment that compromise the facilities are determined. Equipment types would include, but are not limited to, generators, transmission lines, transformers, terminal equipment, series and shunt compensation devices. References to industry rating practices or other standards (e.g. IEEE, ANSI, CSA) should be included when applied."

	Response:- This is a significant improvement. The standard has been changed as indicated. 601(d)(3) in the Compliance Monitoring Process states that the reset period is connected to non-compliance to 601(a). Shouldn't the compliance monitoring process be linked to the measures which are in (b) rather than the requirements? The measures are supposed to be the specific items to look at to insure that you are meeting the requirement. Response: - Valid point, referenced changed as requested. In the levels of non-compliance, 601(e)(1) we are somewhat confused about what "one of the items listed in 601(a)(3)" is. We believe that it refers to the assumptions, methods of rating the bulk equipment and references to industry ratings, but are not sure. It really needs to be clarified. This same concern carries for levels two and three as well. The standard has been modified to clarify what was intended. <u>Specific comments on Requirement 602</u> 602(d)(4) in the Compliance Monitoring Process states that the reset period is connected to non-compliance to 602(a). Shouldn't the compliance monitoring process be linked to the measures which are in (b) rather than the requirements? The measures are supposed to be the specific items to look at to insure that you are meeting the requirement. Response: - Valid point, referenced changed as requested. 602(e)(1) states "Some, but not all requested Facility Ratings….." In 602(a), or (b) it is never stated that the RA, PA, TP, Top need to request particular ratings. In the requirements and measures it only states that the TOW and GO have to provide them. Should the request part be expanded? Response: The premise of the standard is that the involved parties will develop the schedule jointly. However, in cases where a schedule cannot be mutually agreed upon, the needs of the user of the Facility rating values must determine the timing for the exchange of data. It is not feasible to develop a 'universal' schedule that will meet the needs of all the parties subject to this standard. This approach seems to be supported by most commenters. 602(e)(3) requires someone to check the accuracy of the ratings provided against the method identified. Is it intended that the Compliance Monitor be the one to do this? Will the compliance monitor have the expertise and all the information necessary to do this? Response: - 602(e)(3) does not require the Compliance Monitor to check the "accuracy" of the ratings, only the "consistency" of the rating with the methodology documented. The expectation is that anyone who believes there is inaccurate values will bring the inaccuracy to the attention of the entity that provided those values. This supports good utility practice. <u>Specific comments on Requirement 604</u> In 604(b)(2), it indicates that the RA's and Top's shall provide system operating limits to TSP's and TOP's. Do they also

	need to provide it to other RA's? Response: - The standard has been revised to include your suggestion. <u>Specific comment on Requirement 605 and 606</u> The requirements in 605 and 606 apply to Transfer Capabilities. Is this intended only to be TTC, or is ATC also included? It needs to be clarified. Response: ATC is not included in this standard. During the SAR stage, there was strong consensus from industry commenters that ATC did not belong in the standard, due to its commercial impacts. It is not appropriate for a standard to list things not covered. The transfer capabilities in this standard are reliability-based only and are closely tied to the time frames being studied. <u>Overall comment:</u> In reviewing the standard it appears the applicable entities referenced in requirements 601-604 are those defined in Version 2 of the Functional Model. However, in requirements 605 and 606 which address the Transfer Capabilities, it appears that the Reliability Authority is an entity that monitors/oversees the "big picture" for system reliability especially when discussing interregional communication of information to other entities. This leads us to believe that this is really a Reliability Coordinator type entity that has not been defined in the Functional Model. Until this confusion is resolved, it is impossible to create reliability standards that the industry can implement. Response: - This standard is written from the perspective that the RA must have a 'wide area' view, as suggested by the commenter. Please comment on the functional model when it is posted for review.
Independent Electricity Market Segment 2 Khaqan Khan	1) The IMO is concerned about an apparent lack of coordination between Standard 200 and Standard 600. The backgrounder for this comment form correctly identifies that IROLs are a subset of SOLs. The backgrounder goes further to state that the intent of this standard " is to identify all system operating limits and not to differentiate them based upon the impacts of violating them". While, this may be true, the statement raises a coordination issue between this Standard 600 and Standard 200. For example Standard 201 requires the RA to identify IROL Facilities, however it makes no reference on what "Function" has the requirement to determine / derive the IROL Limit. Therefore, Standard 600 must define the need to determine when a limit has a wide area impact. As a first step, Standard 603(4) should include a requirement to describe the methodology used to determine the local and wide spread impact used to determine whether a limit is an SOL or an IROL. Response: The methodology used to determine a SOL and an IROL is the same. An IROL *is* an SOL. For example, both involve running the same type of simulations; consider the same type of contingencies and require meeting the same

	performance standards. The difference is in how widespread the impact would be if the limit is violated. The definition of an IROL is contained in the Operate Within IROL standard. While it is understood that there is a relationship between SOLs and IROLs, it appears most appropriate that IROL be defined in that standard. (2) While Standard 602(a) (2) and 604(a)(2) and the associated measure identify a schedule for the transfer of Limits and Transfer Capability, the standard must recognize the need to provide the Ratings, Limits (SOL and IROL) and Transfer Capability to the required entities that must implement them in a timely manner. Having the best ratings or limits does not ensure the reliability of the system if they are not available to the appropriate authorities on the timeline required for their specific application. Based on the comments in # 5 above, the Reliability Authority should provide the limits to those who require them. Also it is not clear of the context of the word "associated" in 604 (2a). Response: The premise of the standard is that the involved parties will develop the schedule jointly. However, in cases where a schedule cannot be mutually agreed upon, the needs of the user of the Facility rating values must determine the timing for the exchange of data. It is not feasible to develop a 'universal' schedule that will meet the needs of all the parties subject to this standard. This approach seems to be supported by most commenters. The Requirement has been revised so the RA is required to provide the limits to those who have a reliability-related need for them. The following comments are offered with regards to Compliance Monitoring Process. (5) There is a need to define the entity responsible for the role of a compliance monitor. Would it be NERC, the Region, the Reliability Authority or Control area or all. Response: The definition of the Compliance Monitor was approved during the balloting of the urgent action cyber security standard. Currently, the compliance monitor function is performed by NERC's Regions unless the entity being reviewed is an RA that is also a Region. In this case, the Compliance Monitor should be a third party that is unaffiliated with that organization. (Reference the Functional Model Technical Document Section 14 page 22) (6) The Sanction Matrix needs clear instructions on how to interpret the two sanction tables outlined at the end of the standard 600. Response: The SDT has forwarded your comment to the Director-Compliance. The compliance group will be asked to develop background information in response to this and other comments. (7) There is no clear process or mode defined in standard 602(d) for the Compliance Monitor to verify Facility Ratings. Response: - 602(e)(3) does not require the Compliance Monitor to check the "accuracy" of the ratings, only the "consistency" of the rating with the methodology documented. The standard has been revised to add a list of documentation that must be made available to the Compliance Monitor so the Compliance Monitor can verify compliance. Note: The IMO also agrees with the comments submitted by ISO/RTO Standards Review Committee (SRC) of the ISO/RTO

	Council (IRC) Response: Please see the responses to the SRC and IRC.
ISO/RTO Council Segment 2 Endorsed by 7 IRC Members Bruce Balmat	There should be a requirement for coordination of the calculation of limits between planning authorities and reliability authorities. Response: Several commenters suggested that all limits should be developed using a single methodology established by the RA or PA. Because the Planning Authority Area is not required to be the same size as the Reliability Authority Area, requiring that both entities use the same methodology may be impractical. Each of these Authorities may operate in multiple Regions, and may be required to have methodologies that address specific regional concerns. There should be a requirement for coordination of the calculation of limits with neighboring systems. **Response:** The RA and PA are required to provide one another with their methodologies, and with their associated limits, but requiring these entities to coordinate the calculation of those limits does not seem practical.
MAAC Segment 2 John Horakh	The following are "wordsmithing / typo" comments: no issues, but minor changes that should be made. Section 601(d) – Interchange the order of (1) and (2), to be more logical to the "initial compliance" and "subsequent compliance" order. Response: This section of the standard has been revised, and initial compliance is addressed in the implementation plan. Section 601(e)(1), Section 601(e)(2)(i), and Section 601(e)(3)(I) – Replace, in three places, the word "items" with "applicable equipment types", since the reference is to equipment types in 601(a)(3). This suggestion has been implemented and is reflected in the revised standard. Section 603(a)(3) – Replace "603(a)(3)(i)-603(a)(3)(iv)" with "603(a)(3)(i) through 603(a)(3)(iv)", for clarity. Response: This is a style change that would be inconsistent with other standards. Section 603(a)(4)(v) – Replace "603.1.4.1.-1.4.4." with "603(a)(3)(i) through 603(a)(3)(iv)", to conform to the revised numbering system. Response: Please see response above. Section 603(d) – Interchange the order of (1) and (2), to be more logical to the "initial compliance" and "subsequent compliance" order.

	Response: This section of the standard has been revised, and initial compliance is addressed in the implementation plan Section 605(a)(3)(v) – Replace "605(a)(3)(i)" with "605(a)(3)(i) through 605(a)(3)(iv)", since the reference should be to all the preceding conditions. Response: Please see previous response to similar comment. Section 605(d) – Interchange the order of (1) and (2), to be more logical to the "initial compliance" and "subsequent compliance" order. Response: This section of the standard has been revised, and initial compliance is addressed in the implementation plan Section 605(e)(3)(iiii) – Replace "equipment types" with "items", since the reference is to items in 605(a)(3). Response: The levels of non-compliance have been modified in a manner that no longer includes the same type of referneces.
MAPP Segment 2 Endorsed by 8 Members Lloyd Linke	This standard and standard 200, should coordinate with each other, especially if the concept of an IROL is adopted and defined. If this is the case, IROLs should be defined and addressed within this standard Response: The methodology used to determine a SOL and an IROL is the same. An IROL *is* an SOL. For example, both involve running the same type of simulations; consider the same type of contingencies and require meeting the same performance standards. The difference is in how widespread the impact would be if the limit is violated. The definition of an IROL is contained in the Operate Within IROL standard. While it is understood that there is a relationship between SOLs and IROLs, it appears most appropriate that IROL be defined in that standard.
Manitoba Hydro Segment 1,3,5,6 Gerald Rheault & Ron Mazur	• Comments This version is much clearer than previous versions – but this clarity highlights an inconsistency for system intact evaluations in the planning time frame. Response: The standard is based upon the reality that the system is almost always operated in a condition that is not intact, thus planning studies must assess system performance beyond n-1 so that the impacts are known. The transmission planning standard (currently in the SAR stage) must be coordinated with this standard. • The Performance-reset Period definition is not compatible with the context in which it is used in the standard. For example, in 601 (d) (3), the performance-reset is the time since the last non-compliance which is different than what is said in the definition. The definition in 601 (d) is the correct one. Response: Your comment is correct; the definition at the beginning of the standard has been modified accordingly.

	• It is not clear how the development of each methodology and schedules by multiple parties is to be coordinated. Who has authority to resolve disputes?. Response: The user of the data is the one who has the ultimate say regarding the schedule. The NERC (and regional) processes have provisions for dispute resolution. • In item 603 (a)(40(v) there is a mistake in the numbers referenced in conditions listed at end of sentence. Item 603.1.4.1 – 1.4.4 should be 603(a)(4)(i) – (a)(4)(iv). Response: Agree, thank you. These comments represent additional comments prepared by Ron Mazur, Manitoba Hydro General Comments 1. Each standard should have a "responsible entity" section. The standards use the term "responsible entity" in some cases, and refer to the responsible entities defined in the Functional Model (Reliability Authority (RA), Planning Authority (PA), Transmission Planner (TP), Generator Owner (GO), etc) in other cases. In many cases, responsible entity seems to have the obligation to provide the documentation/data to itself. The SDT should review the use of the Functional Model terminology throughout each standard and clarify the roles and obligations to eliminate the confusion. Response: The use of the term "responsible entities" is to avoid having to repeat the names of all the entities in every requirement. The entities are listed in the requirement in each case. This approach is consistent with other NERC standards. 2. Further to item 1 above, the measure will assign an obligation for the responsible entity (Transmission Owner (TO) or GO) provide documentation to the RA, PA, TP, Transmission Service Provider (TSP) or Transmission Operator (TOP). The levels of Noncompliance then repeat the list of entities that are to receive the documentation. The Standards could be made more readable by eliminating such unnecessary duplication. Response: Doing as suggested may confuse instead of reducing unnecessary duplication. 3. Since the standard includes a Compliance Monitoring Process and Levels of Noncompliance, the SDT should also include a section on what is expected for mitigation of non-compliance. Response: Mitigation of non-compliance is outside the standard and is rather administered via the NERC compliance program.

	4. The number of levels of bullets (e.g. 605(a)(3)(iii)) makes the standard difficult to read. Other section naming designations should be considered. Response: The format of the standards has already been changed once to add more clarity Not sure that much can be done to improve it. Your suggestions are most welcome. 5. Each standard should be reviewed to ensure all defined terms are appropriately marked (capitalized when used in the text). Similarly, a statement should be added to indicate that other NERC definitions are capitalized. Response: Agreed. 6. I am concerned that the SOLs and Transfer Capabilities defined in these standards for operation will not be determined using the same level of performance (existing NERC Planning Standard I. A. Table I Category B and C) as is used for planning the system. Response: The standard is based upon the reality that the system is almost always operated in a condition that is not intact, thus planning studies must assess system performance beyond n-1 so that the impacts are known. The transmission planning standard (currently in the SAR stage) must be coordinated with this standard. Definitions • Where possible NERC Standard definitions should be used. Where used, the NERC definitions should also be capitalized (e.g. Bulk Electric System). • Delayed Fault Clearing: What is a protection group? The Normal Clearing definition uses "protection system". • Facility: An element is normally defined as a group of equipment that is relayed together. Why not used the more common terminology. • Equipment Rating: Uses the term "equipment apparatus" while the Facility Rating definition uses "equipment". • Performance-reset Period: The definition is not compatible with the context in which it is used in the standard. For example, in 601 (d) (3), the performance-reset is the time since the last non-compliance. • System Operating Limit: All defined terms (Facility(ies), Facility Ratings, System Operating Limits) should be capitalized. Where is the term "reliability criteria" defined? • Transfer Capability: Capitalize "system operating limits"

	Response: Suggestions noted and incorporated into the standard where possible. The SDT has tried to stay with existing definitions. However, in some instances the existing definitions may carry with them history that could introduce confusion. The SDT will look for opportunities for improvement. Standard 600 • Purpose: The purpose may be more appropriately stated as: "To document methodologies used, and to determine and communicate Facility Ratings, System Operating Limits and Transfer Capabilities of the Bulk Electric System." • Purpose: Capitalize bulk electric system. Response: The purpose statement has been modified in response to this and other comments. • Effective Date: What existing Operating Policy(ies) and Planning Standards will these Standards replace on the effective date? Does the SDT have a plan to transition to the new Standards? Response: An implementation plan will accompany the standard when it is balloted. Standard 601 • 601 (a) (3): Capitalize bulk electric system. Response: Agree. • 601 (b) (1): Clarify who has responsibility to make the methodology available (TO and GO). While the Compliance Monitor requires the documentation of the rating methodology, is it required by the other entities, and is this proposed obligation consistent with the SAR? Response: Your point is taken, but would add redundant terminology to the standard and is not deemed necessary. The standard is consistent with the SAR. • 601 (b) (2): This measure requires the methodology to contain all items specified in 601 (a) (2) and 601 (a) (3). The wording "as applicable to the responsible entity" should be added, since the TO, for example, would not discuss generator rating methodology. Response: Any entity not owning a particular equipment type should not be found noncompliant for not having a

	methodology to rate it. Such a noncompliance finding would be overturned upon appeal. • 601 (e): The Levels of Noncompliance should include the wording "as applicable to the responsible entity" as noted in the bullet above to allow TO who does not own generation, or a GO who does not own transmission to be compliant. Response: Please see response above. Standard 602 • 602 (b) (1): Define responsible entities. Response; See previous response. • 602 (b) (2): Rather than using a pre-defined schedule, the ratings should be provided whenever they are established or recalculated. Response: The user of the data may request ratings whenever they are established or recalculated in this standard, as you suggest. • 602 (d) (3): The impacted parties should be defined and limited to the entities with a verifiable need for the data. Response: "Impacted parties" has been removed in response to this and other comments. • 602 (e) (3): There is more impact on reliability if ratings are not provided. Providing ratings that are inconsistent with methodology should be the lowest level of noncompliance. Response: The standard supports the comment that not providing ratings has the highest impact (this is assigned as a level 4 noncompliance). Standard 603 • 603 (a) (1): Define the responsible entities. Response: Please see previous response to similar comment. • 603 (a) (3): This section of performance criteria should be an attachment that can be referenced by Standard 604 and Standard 606 – it is not part of the methodology. Response: NERC has adopted a philosophy that requires that all relevant material be contained within the body of the standard itself. Information contained in reference documents is not enforceable. • 603 (a) (3) (i) A): Use "applicable loading" instead of "thermal" in this section and throughout the standard – why not use the terminology already established in the NERC Planning Standard I. A. and its associated Table I. Response: The standard has been revised in response to this and other comments.

	• 603 (a) (3) (i) B): This may be possible for new facilities but what were the planned conditions. Can the SDT explain the intent n more detail. Is the objective to ensure that the system is operated to the same standard to which it was planned? Response: Not necessarily, although consistency is expected. SOLs may be determined for a wide range of system conditions. For example, to be consistent with planned system conditions, a SOL for an off-peak condition should not be established based on on-peak conditions unless they would result in more restrictive SOLs. • 603 (a) (3) (ii) A): This contingency section should use the same terminology as was used in the existing Planning Standard Table I. For example, Contingency A) (a) should use the words "For the loss of a single element (Facility is used by the SDT) due to" (a) Single line to ground …. ., as it is not clear as written that an element is loss due to the fault. Response: Because the referenced text includes normal clearing, this indicates that the facility has been lost. • 603 (a) (3) (iii): Similar to the bullet above, replace "Response to the first contingency" with "Response to the loss of a single element". Response: This suggestion may result in confusion (element vs. facility). • 603 (a) (3) (iii) (a): Use "applicable loadings" instead of "thermal". Response: See previous response to similar comment. • 603 (a) (3) (iii) (e): Define "affected area" – Can the SDT provide criteria to define an "adverse impact"? Response: "Affected area" is included because impacts may extend beyond that directly connected to the faulted facility. "Adverse impact" is one that will cause or has the potential to cause violation of reliability criteria. • 603 (a) (3) (iii) (f): What "system adjustments are allowed? Is generator tripping allowed for following the loss a single Facility? Response: System adjustments include redispatch, reconfiguration, etc. Yes. • 603 (a) (3) (iii) (g): Does a system adjustment allow curtailment of firm transfers as is specified in Table I notes of the existing NERC Planning Standards. Such reliability curtailment would have to be done outside of the pro-forma tariff which requires pro-rata load curtailment with firm transfer curtailment, since loss of load is not permitted for a single credible contingency. Response: The system adjustments in this section are meant to allow the SOL to be set such that the emergency ratings would not be exceeded after loss of a Facility, taking into account the appropriate SPS or RAS. This should not involve curtailment of firm transfers because all firm transfers are supposed to fit within the SOL in the planning horizon. • 603 (a) (3) (iv) (a): Use "loadings" instead of "thermal". Response: Please see previous response to similar comment. • 603 (a) (3) (iv) (e): Define: affected area".

	Response: Please see previous response to similar comment. • 603 (a) (3) (iv) (f)/(g): Can firm transfers be interrupted as well as load? Why is load interruption allowed for a single (NERC Table I Cat B) event? This represents an unacceptable degradation in performance criteria. Response: Yes, impacts to firm transfers have been added under the phrase, 'uses of the transmission system' • 603 (a) (4) (ii): Can the SDT explain what is required to deal with model accuracy? Benchmarking, sensitivity analysis to load level, load power factor, etc? Response: The intent of this section is to allow description of how uncertainties are accounted for in determining the SOL. For example, inaccuracies in load models can be addressed by using sensitivity studies. • 603 (a) (4) (v): Reference appears to be incorrect. Response: Agree. This will be corrected. • 603 (a) (4) (b) (i): Should the transmission Service Provider (TSP) be included in the list of those receiving the methodology (see 604(a) (2) – TSP receives data). Response: No. The TSP does not have the responsibility for determining SOLs or TCs, but rather administers the transmission tariff. • 603 (a) (4) (c): The regional difference is requiring that SOLs be determined by considering some of the Category C contingencies from Table I of the existing I. A. What is the SDT"s argument for setting SOLs using a lesser standard? Response: NPCC has requested a regional difference, consistent with their current criteria. According to the NERC standards process each region can adopt a more stringent standard if it so chooses. • 603 (a) (4) (d) (2): Define responsible entities. Response: Please see response to similar comment. Standard 604 1. 604 (a): Clarify/confirm the responsible entities. It appears that PAs provide SOLs to PAs (to themselves?) for the area they are responsible. Response: Please see response to similar comment. 2. Section 604 should contain the performance criteria in Section 603 (a) (3), or reference it as the performance criteria used to establish the SOLs. Response: The reference is included in 604(b)(1), as suggested. 3. 604 (b) (2) & (3): Should the obligation to provide data be on a schedule, or as it becomes available? Response: The standard does not preclude either option as long as it is requested by the associated RA, PA, Transmission

	Operators, or Transmission Planners. 4. 604 (d) (2): Reword the phrase "the Compliance Monitor shall verify by information submittal" – the responsible entity will be the one providing the information (not the CM). Response: The Standard will be modified to clarify this. 5. 604 (d) (3): Define "impacted party". Response: Impacted party has been removed. Standard 605 • 605 (a) (3) (iv): Can the SDT explain what they expect to see in a discussion of "Current and projected transmission uses"? Response; The intent of this section is to require description of the assumptions made in determining the Transfer Capabilities. This would include load, transfers, etc. • 605 (a) (3) (v): Why is uncertainty only limited to 605 (a) (3) (i) – system topology? Response: This has been revised to clarify that identifying uncertainties is applicable to all the topics listed. • 605 (b) (i): Clarify who the responsible entities are (again the RA makes the methodology available to the RA). Response: The RA makes the methodology available to adjacent RAs (not to itself). • 605 (d) (1) (iii): Clarify the nature of the compliant and who can make the compliant. Response: Any entity can lodge a complaint. Standard 606 • 606 (a): What performance criteria are to be used to establish Transfer Capabilities? A reference is required to Standard 603 (a) (3), or preferably, the section should be an Appendix common to Standards 604 and 606. Response: Standard 606 specifies that it would be established based on the methodology in Standard 605(a)(2), which requires that "The methodology required in 605(a)(1) shall state that Transfer Capabilities shall adhere to all applicable System Operating Limits. • 606 (b) (1) and (2): Define the responsible entities. Also, I believe that the obligation to communicate data should be tied to whenever the transfer capabilities are calculated or recalculated, instead of on a pre-determined schedule, or perhaps in addition to a schedule.

	Response: The responsible entities are identified in 606 (a) (1) • 606 (d) (2) Clarify who is to provide the information submittal – it is not the CM. Response: This has been revised to add clarity. • 606 (e): Since the measures in 606 (b) define the entities that are to receive the data, readability of the standard(s) would be enhanced if the information were not repeated in the Levels of Noncompliance. Response: Please see response to similar comment you made previously.
MidAmerican Segment 3 Tom Mielnik	This standard and Standard 200 should be coordinated with each other. If the concept of an IROL is adopted and defined, then IROLs should be defined and addressed within this standard. Response: The methodology used to determine a SOL and an IROL is the same. An IROL *is* an SOL. For example, both involve running the same type of simulations; consider the same type of contingencies and require meeting the same performance standards. The difference is in how widespread the impact would be if the limit is violated. The definition of an IROL is contained in the Operate Within IROL standard. While it is understood that there is a relationship between SOLs and IROLs, it appears most appropriate that IROL be defined in that standard.
Midwest ISO Segment 2 Terry Bilke	• MISO is in support of the comments drafted by the ISO-RTO council. Response: Please see responses to the IRC. • There is no mention in this standard regarding coordination with neighboring entities. Transfer capability cannot be determined in a vacuum. Response: **Under Requirement 605 a, the methodology for developing TCs, must include consideration of the system operating limits provided to the RA and PA.** • There is a common issue with the functional model. Who is the RA? Some people believe it is the current Reliability Coordinator. Some people believe it is typically the existing TO. There will be problems monitoring compliance if it is unclear who is responsible for what. Someone needs to create a table that shows a mapping of current entities and the role they appear to match under the functional model. Response: This is a common question, that must be addressed outside of any specific NERC standard. Please submit comments to the FMRTG. • What if an entity in this standard belongs to multiple Regions? Will there be multiple compliance jeopardy and differing expectations of what is compliance? Response: This must be handled via the administration of NERC's compliance program.
Mirant Segment 6 Alan Johnson	Still have a few concerns: Section 602 (e), items 1,2 and 4. The last sentence of all three items reads"…in accordance with their respective schedules." Would like to see this modified to read, " in accordance with their respective duly noticed and publicly available

	schedules." This request is made to acknowledge that there is a two-sided responsibility here. The TO and GO have a responsibility to provide Facility Ratings. However, the RA, PA, TP, and TOP have a responsibility to clearly identify what information it requires and to allow sufficient lead-time for the TO and GO to provide it. If this is not done, the TO and GO should not be subject to sanctions under items 1,2 or 4. Response: The user of the data determines the schedule, based upon its reliability needs. Section 605 (a): This section deals with the calculation of TTC which is a core reliability issue. The standard should be tighter, more defined so that consistency is achieved within and across the interconnections regarding the calculation of transfer capability. This is consistent with direction from the NERC Board at its February 20, 2002 meeting. Sub-item (v) looks a lot like TRM of today. As described within the proposed standard, the responsible entities are allowed too much flexibility to come away with a uniform standard for the calculation of TTC. This issue should be given further consideration, especially post 8/14/03, prior to ballot Response: During the development of the SAR associated with this standard, there was strong industry consensus not to include ATC or its margins in this standard or to require the use of a single methodology for determining ratings, limits or transfer capabilities.
NYISO Segment 2 Robert Waldele	Sections 604, 605 and 606 make references to "responsible entities." There is a concern that this may lead to conflicting objectives among the reliability authority, transmission planner, etc. Further, the phrase "schedule established by the transmission operators and transmission service providers" weakens the role of the Reliability Authority. The RA should have the final determination of what schedule is appropriate. Response: The use of the term "responsible entities" is to avoid having to repeat the names of all the entities in every requirement. The entities are listed in the requirement in each case. This approach is consistent with other NERC standards. The user of the data determines the schedule, based upon its reliability needs. The document should clearly define whether IROLs are a subset of SOLs (or the converse). Should IROLs be coordinated among Reliability Authorities? Response: Coordination and data exchange between RAs is addressed in the Coordinate Operations standard. The Operate Within IROL defines what an IROL is. The NYISO supports the consensus comments submitted by the ISO/RTO group. Please see the responses to the IRC.
NY State Reliability Council Segment 2 Alan Adamson	The NYSRC is opposed to monetary sanctions as the only option for dealing with noncompliance as applied in this and other proposed NERC Standards. Unfortunately, direct monetary sanctions invite "gaming the system", and encourage "business" decisions based on potential profits or savings versus potential penalties. Instead of monetary sanctions, the NYSRC prefers that NERC have the authority to issue letters of increasing degrees of severity to communicate noncompliance of mandatory standards. The NYSRC and NPCC now rely on a more stringent and mandatory process than monetary sanctions to assure compliance with reliability standards. Compliance is now mandatory through the contractual agreements and tariffs that all participants need in order to conduct business. The use by the NYSRC and NPCC of letters to regulatory agencies and other oversight bodies for reporting noncompliance has demonstrated that letter sanctions are a more effective tool for

	ensuring adherence to standards. Such letters establish the basis for liability in the event of a subsequent criterion violation, and in the case of market participant noncompliance, threaten the violator's ability to do business with or through an ISO or RTO. Moreover, letters that communicate noncompliance best allow focus on the "root cause" of a violation, as well as its reliability impact. Therefore, the NYSRC recommends that this and other NERC Standards expressly provide that letter sanctions be used in addition to or instead of monetary sanctions under circumstances in which they would be an equally or more effective enforcement mechanism. Response: The sanctions table includes a letter as part of each of the sanctions. The concern about financial sanctions has been forwarded to the SAC for their consideration, but removing the financial sanctions from the sanctions table is outside the scope of the SDT.
NPCC CP9 Segment 2 Endorsed by 7 Members Guy Zito	NPCC feels there are coordination issues between Standard 200 and this one. Additional work is needed to ensure there is a seamless flow between the two Standards. This lack of coordination has been identified as a concern in the recent Standard 200 balloting. Response: The drafting team agrees and will work with the Standard 200 drafting team to accomplish this. The IROL SDT has added a reference to this standard to indicate that IROLs are developed under the Determine Facility Ratings…standard. NPCC feels it is not made clear that System Operating Limits (SOLs) need to be recalculated as the system topology changes. Also time horizons for SOLs should be established. These crucial requirements do not appear anywhere in Requirement 603 or its associated measures. Response: The standard has been revised to include the following statement: In the determination of System Operating Limits, the system condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. Requirement 603 has been subdivided to improve its clarity. In the revised standard, the PA and the RA are each responsible for ensuring there is a methodology for developing SOLs. The PA is responsible for ensuring there is an SOL Development Methodology for use in developing SOLs used in the planning horizon – and the RA is responsible for ensuring there is an SOL Development Methodology for use in the operations horizon. In addition, a requirement was added for the RA and PA to have an agreement with one another on the time horizons addressed by each of their methodologies. Definition of Inter-Regional and Intra-Regional, what does an area consist of? Response: The terms inter and intra regional mean inside and between the current NERC Regions. What Transfer Capability time horizon needs to be used and should it be based on peak only? Response: Theses will be described in the methodology and defined by the requestor of the information. NPCC feels there must be a clear methodology or practice identified for the establishment of System Operating Limits. The methodology required in Standard 603(a)(3) should either identify an industry wide process for the establishment of SOL (and IROL) directly in the standard or an associated Technical Reference. Response: It is not practical to develop and implement a single methodology across all of North America. During the

	devleopment of the SAR, industry consensus did not support the use of a single methodology. In Section 602 b 2 the standard should specify that the schedule that is established is reasonable and can be met. Response: The user of the information must have the ultimate say here. An ureasonable schedule can be appealed via dispute resolution, if necessary. In Section 603 a 1 the standard needs to indicate which of the entities has ultimate accountability for establishing the operating limits methodology. It is recommended that the Reliability Authority should have this accountability. Without this, multiple methodologies might be used. Response: The RA has responsibility for the methodology it uses for determining operating limits. The PA has the responsibility for the methodology it uses in the planning horizon. A requirement has been added to the standard to require that the methodolgoy include a definition of the applicable operating and planning horizons addressed within that methodology . In the Compliance section NPCC would again like to voice its opposition to monetary sanctions and feels that market mechanisms and letters of varying degrees of severity be utilized to enforce compliance. Response: The concern about financial sanctions has been forwarded to the SAC for their consideration. The SDT does not have any authority to remove the financial sanctions from the Sanctions Table. The Sanctions Table has been approved by the NERC Board.
OPPD Segment 1 John Mayhan	The definition of the word "Facility" is not clear enough to determine whether the following would be included in the list of contingencies that must be evaluated: A fault, with Normal Clearing, on a bus section, resulting in more than one branch of the transmission network being removed from service A fault internal to a circuit breaker, resulting in more than one branch of the transmission network being removed from service. Response: Wording has been revised to address concern. This is addressed in the revised description for contingencies.
PJM Segment 2 Joe Willson	Problem with this Standard 600 has to do with the non-compliance elements. For example requirement 601 (e) Levels of Noncompliance, every level 1 and 2. " or does not address one of the items listed in 601 (a)(3) . However, when you read the requirement, it states the following: 601 (a) (3) The methodology required is 601 (a)(1) shall identify the assumptions used to determine Facility Ratings ..... Are determined and references to industry rating practices or other standards (e.g. IEEE, ANSI, CSA), when applied. It does state “including the method by which…” so what is being measured? The assumptions or specific methodology for devices? If the later it need to be more descriptive of “electric system equipment types” Response: The standard has been revised to support your suggestion. For 602 The non-compliance levels are not measurable unless someone is collecting all the facility information (existing and new facilities) and then comparing it or asking the RA if they have revised ratings for these pieces of equipment. Levels one and two have "some but not all" without any way of determining what all is. Level 3 (methodology) doesn't belong here. Response: Level 3 is a feedback loop to make sure that the determined values are consistent with the methodology. “Some

	but not all" is based upon *requested* information. The requestor should certainly be aware of what pieces of data are being asked for and can make a determination if everything has been received. 603 The compliance monitoring process doesn't even specify what the compliance monitor will be checking. Submit any information and you are compliant? Also problems with non-compliance levels The requirement is for a methodology but level 3 is based on performance to that methodology. Response: Level 3 of 603 is not performance to the methodology (that is actually covered in 604). The measures and requirements outline the information the compliance monitor will need to review. In addition, the compliance monitoring section has been modified to include a list of documentation that must be made available to the Compliance Monitor.
Reliant Energy Segment 5 Charles Yeung	The DFR Standard appears to lack requirements for TSPs and Regions to coordinate the development of Facility Ratings and System Operating Limits that impact more than a single system. Response: Facility owners are responsible for establishing Facility Ratings for their facilities. The TSP and the Region are not responsible for establishing limits or for coordinating the development of limits that impact multiple systems. The written discussion to Recommendation # 14 specifically requests that "Reliability Regions will review system design, planning, and study methods and practices within their respective regions to ensure such activities are technically adequate and coordinated among the entities within the region." The discussion goes on to place the coordination beyond the regional level, "NERC and the Reliability Regions will review the scope, frequency, and coordination of interregional studies, to include the possible need for additional simultaneous transfer studies based on transactional trends." So, it seems the recommendation calls for NERC to take a lead role in requiring Regions to consider the impacts of market transactions that traverse regional boundaries when assessing transmission facility ratings methods and practices. This last point contemplates coordination of facility ratings by considering market transactions. Is this not what ATC is about? How will industry embody such a requirement? Should there be a ATC coordination requirement? Will NERC expect Regional Councils or NAESB be the organization(s) to propose any ATC coordinated calculation methodology to complement the NERC DFR standard? Response: Transactions are part of the assessment study used to determine system operating limits, using the facility ratings provided – but the assessment does not change the value of the facility ratings. Since this standard requires all ratings to be considered in the development of system operating limits, coordination with respect to equipment ratings is already addressed. Standard 100 addresses coordination between Reliability Authorities. Addressing ATC is beyond the scope of the approved SAR. During the development of the SAR, the industry indicated in its comments that ATC should not be included in this standard.
SERC Segment 2	1. Section 603 (a) (4) (v): References listed at end of sentence need to be updated to the new format.

Susan Morris	This has been updated. 2. Section 603 (c) (1) (ii): What constitutes Emergency Transfer Capability system conditions? Response: This is applicable just to NPCC and its definition is contained within the context of section 603(c) (1) (ii). . 3. Section 604 (b) (2) and (3): Paragraphs are confusing as to what SOLs are addressed. Suggest paragraph (2) address operating horizon and paragraph (3) address planning horizon. Throughout the standard a clearer distinction of the timeframes being addressed would be beneficial. Response: Section 604(a)(3) requires that the methodology address the horizon being addressed. Section 604 (d) (1): The Transmission Planner function should be included in the annual verification process of the Compliance Monitoring Process. Response: The Compliance Monitoring Process has been revised to omit this verification process so this suggestion was not adopted.
SERC Operations Planning SubC Segment 2 Endorsed by 8 Members Segments 1,4,5 Don Reichenbach	The references and reliance of this standard on the still-evolving Functional Model, with the identified deficiencies (as pointed out by the SDT on page 3 of this document) is bothersome. The standard makes assumptions based on what is believed or hoped will be in a future version of the Functional Model. It would be prudent to wait on a more mature version of the Functional Model before approving standards based upon it. Response: If this standard is approved by the Ballot Pool, the FM will be modified to reflect this standard. There is a lack of coordination between Standard 200 and 600 that needs to be resolved. Response: The Standard 200 has been modified to include specific language linking the determination of IROLs to SOLs. Each SDT must work to develop a standard that is within the scope of its associated SAR. Each SDT must be responsive to the comments submitted by the industry. This standard (600) is focused on developing a methodology for determining SOLs and for developing a set of SOLs - the IROL standard is focused on identifying which SOLs are IROLs and requires operation within IROLs. The IROL Standard added a note to state that IROLs are a subset of SOLs developed according to the Determine Facility Ratings… Standard. Section 603 (a) (4) (v): References listed at end of sentence need to be updated to the new format. Response: This entire requirement has been modified to address industry concerns about clarity. Section 603 (c) (1) (ii): What constitutes Emergency Transfer Capability system conditions? Response: This is applicable just to NPCC and its definition is contained within the context of section 603(c) (1) (ii). . Section 604 (b) (2) and (3): Paragraphs are confusing as to what SOLs are addressed. Suggest paragraph (2) address operating horizon and paragraph (3) address planning horizon. Again, throughout the standard a clear distinction of the timeframes being addressed would be beneficial. (Reference comments under #1 & 2.)

	Response: Section 604(a)(3) requires that the methodology address the horizon being addressed. Section 604 (d) (1): The Transmission Planner function should be included in the annual verification process of the Compliance Monitoring Process. Response: The Compliance Monitoring Process has been revised to omit this verification process so this suggestion was not adopted.
TVA Mark Creech	(TVA agrees with the SERC Planning Standard Subcommittee). 1. Section 603 (a) (4) (v): References listed at end of sentence need to be updated to the new format. Response: This entire requirement has been modified to address industry concerns about clarity. 2. Section 603 (c) (1) (ii): What constitutes Emergency Transfer Capability system conditions? Response: This is applicable just to NPCC and its definition is contained within the context of section 603(c) (1) (ii). . 3. Section 604 (b) (2) and (3): Paragraphs are confusing as to what SOLs are addressed. Suggest paragraph (2) address operating horizon and paragraph (3) address planning horizon. Response: Requirement 604 has been modified to clarify that the SOLs developed by the RA are for use in the operations horizon, and the SOLs developed by the PA are for use in the planning horizon. 4. Section 604 (d) (1): The Transmission Planner function should be included annual verification process of the Compliance Monitoring Process. Response: The Compliance Monitoring Process has been revised to omit this verification process so this suggestion was not adopted.
Southern Cal Edison Segment 5 Neil Shockey	It appears certain definitions used in this standard are geared toward “normal operating conditions” and do not adequately address real time events, which can and do change equipment and facility ratings. For example, a generator RAS may be activated real time that impacts (lowers) a Facility Rating or Equipment Rating. If this is not the intent of this standard, it is recommended that the definition of Facility Rating be changed to read: “…comprising the facility under normal operating conditions.” Response: The standard is intended to apply to all operating conditions. Facilities have ratings which are conditioned on time and other variables. Facility ratings must be respected in the establishment of system operating limits – and system operating limits must be respected in the establishment of transfer capabilities.

Southern Co Services Segment 1 Marc Butts Southern Co Gen & Energy Marketing Segments 5,6 Roman Carter	1. Section 603 (c) (1) (ii): What constitutes Emergency Transfer Capability system conditions? Response: This is applicable just to NPCC and its definition is contained within the context of section 603(c) (1) (ii). . 2. Section 604 (b) (2) and (3): Paragraphs are confusing as to what SOLs are addressed. Suggest paragraph (2) address operating horizon and paragraph (3) address planning horizon. Response: Section 604(a)(3) requires that the methodology address the horizon being addressed. 3. This and all NERC Reliability Standards should be very clear in requiring a Company to provide Facility Ratings, Operating Limits, and other data for "Reliability-based" needs only. The schedule for requesting the data from the Company shall be reasonable for the scope and type of data requested. Response: Agreed. If unreasonable requests are made these can be addressed through dispute resolution. 4. There may be some confusion between what constitutes a Facility rating versus an Operating limit in some cases. For example, the reactive capability or rating of a generator is typically considered to be the limit based on the machine D curve or capability curve. However, the generator bus voltage or auxiliary bus voltage may limit the reactive capability of a particular generator for certain system or operating conditions. Unless the reactive limit in VARs is a single value (which it usually is not), this is normally referred to as an operating limit. However, classifying such a limit as the reactive power "Facility rating" for the generator seems to be what this standard requires. We request clarification on this. Facility ratings must be respected in the establishment of system operating limits – and system operating limits must be respected in the establishment of transfer capabilities. Response: A Facility Rating is applicable for a defined set of conditions. Your interpretation is consistent with the intent of the standard. 5. Standards approved using the Functional Model paradigm prior to the Functional Model being implemented should require some type of transitional language applying the Standard to a Control Area environment. Future changes to the Functional Model should also be fully coordinated and synchronized with the NERC Standards. Response: Agreed 6. Section 604 (d) (1): Need to add Planning Authority and Transmission Planner in this monitoring process to be consistent with 604 (a) (2). Response: The Compliance Monitoring Process was modified to omit this verification, so your suggestion was not adopted. 7. Section 603 (a) (4) (v) has wrong references. It should refer to sections located at 603 (a) (4) (i) through 603 (a) (4) (iv). Response: This requirement was significantly revised and the numbering has been corrected in the revised version. 8. Sections 605 and 606 should include "Transmission Planner and Transmission Operator". We realize the Standards Drafting team had earlier responded that the Standard does not prohibit the Transmission Operator (or Planner) from participation, but it likewise doesn't specifically say they are allowed input. Response: These activities may be delegated to other functions, but it is the responsibility of the RA and Planning Authority.

SPP Operating Reliability Group Segment 2 Endorsed by 5 Members, Segment 1 Scott Moore	In 601(e)(2)(i), what are the items referred to in 601(a)(3)? Response: These were intended to be equipment types – the standard has been changed to clarify this. In 602(e), what was the thought process involved in deciding that not being consistent with methodology was more critical than not having a specific rating? Similar situations also occur in 604(e) and 606(e). Response: The SDT believed that the lack of ratings for existing facilities –there would be a past record for those facilities that could be used if necessary and this should be a Level 1. Level 2 is more severe than Level 1 because there isn't a past record for those ratings level 3 is more severe because it calls into question the validity of all the ratings provided. Level 4 is most severe because the ratings weren't available when needed. The same philosophy was applied to 604(e) and 606(e). The severity of the penalty for noncompliance should not be based upon whether the facility is an existing facility or a new facility as is stated in 602(e)(1) and 602(e)(2). The sanctions should be the same in either case since the consequences for exceeding these ratings would be the same. Response: See above. Shouldn't curtailments of transfers be included in 603(3)(iii)(g) and 603(3)(iv)(g) since they are one of the most commonly used responses to overloads? Response: The wording has been modified as suggested – and is considered to be one of the 'uses of the transmission system'. Shouldn't the reference in 603(4)(v) be 603(a)(4)(i)-(a)(4)(iv)? Response: The draft standard contained two-604(d)s. The last one should have been 604(e). The use of "some, but not all requested" terminology in a situation that is in fact "all are required" lessens the intent of the standard. The language used in the first draft was more direct. Why did the SDT change it? Response: The language was added to distinguish between level 4 where none of the ratings were provided per schedule, and other levels where some of the ratings were provided per schedule.
WECC TSS Endorsed by 26 Members Segments 1,2,3,4 Chifong Thomas	The WECC TSS would like to complement the SDT on this revised draft standard. It is obvious that a great deal of effort has been expended in developing the draft and in responding to industry comments. We have some additional minor comments on Draft 2: (1) Some of our reviewers are not sure why the definition for "Cascading Outages" was changed to exclude the second sentence, "Cascading results in widespread electric service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies". This second sentence would clarifies the extent of the outages and should be included.

	Response: The definition of cascading outages, has been modified, but not as suggested to partially address your concern. The preponderance of industry comments received on the same definition posted with Standard 200 indicates that there is no common understanding of what is meant by the term, 'widespread'. This definition will continue to be modified as a result of industry comments until a definition has been developed that meets industry consensus. (2) Some of our reviewers were confused by the definition of Facility. It might be helpful to also define Equipment. This additional definition would help clarify the Facility definition. A draft definition for Equipment is provided below: Equipment: A single piece of electrical apparatus that can comprise a portion of a Facility and that has ratings that may limit the capability of the Facility of which the electrical apparatus is a part. Examples of Equipment include: disconnect switches, circuit breakers, generator excitation systems, line voltage regulators, and line conductors. Response: Requirement 603 has been modified to clarify the distinction between equipment and a facility. With this modification, the SDT doesn't think the term 'equipment' needs to be defined. (3) We are confused about the use of the "minimum" values in the definition of SOL, since, depending on the specific value referenced, these terms may not be applicable. (For example, what would a minimum current limit apply to?) We understand that the definition must be broad enough to cover limits that are set based on parameters other than MW or MVAR flows. Perhaps rewording the definition by separating it into two parts and some examples may help. Response: The definition was not changed. The definition of SOL included some examples of the parameters that may be addressed by a SOL. For example, a DC Tie would have a minimum current limit - or a SOL may be based on a minimum voltage criteria. (4) Standard 200 refers to the Interconnection Reliability Operating Limit (IROL) as a subset of SOLs and only would enforce that subset of limits. Standard 600 does not refer to IROLs or explain/identify the requirement for documenting the methodology and developing these specific limits, unless it is implied in 603 and 604. 600 and 200 need to be linked. Response: Standard 200 has been modified to include a reference to this standard. A new SAR has been submitted to the SAC that addresses monitoring and controlling to operate within system operating limits – the new SAR states that the SOLs identified are not IROLs. (5) 601(a)(3) is a long sentence. We suggest rewording for readability, as follows: "The methodology required in 601(a)(1) shall identify the assumptions used to determine Facility Ratings, including: • the method by which ratings of major bulk electric system equipment types that comprise the Facilities* are determined and • references to industry rating practices or other standards (e.g., IEEE, ANSI, CSA), when applied. *Facilities for which rating methodologies are required include, but are not limited to, – generators, – transmission lines,

	– transformers, – terminal equipment, and – series and shunt compensation devices" Response: The SDT did modify this requirement so it is easier to read and understand. This supports your suggestion. (6) Section 601(d)(2) allows entities one year to get in compliance after adoption of the Standard. This is a very tight time frame and significant reporting burden; after all it generally takes longer than a year to just write a standard. We suggest a longer time frame for entities to initially comply. Similar comment for 603(d)(2) and 605(d)(2). Response: The Compliance Monitoring sections of the standard have been modified to remove the language that addressed the first year this standard is implemented, since that language is duplicated in the Implementation Plan. This standard does not require much documentation beyond what is already required by existing operating policies and planning standards. Please review the details of the implementation plan and let us know if you think there are areas where entities should be given more time to achieve full compliance. (7) 601(e) Levels of noncompliance. Suggest adding words on all levels to the effect that the non-compliance levels do not address non-*applicable* items. We have seen confusion on noncompliance levels where missing items would determine noncompliance when some of the items listed may not be applicable to all entities Response: The compliance elements are intended to be reasonable. The standard requires entities to document the methodology used to rate their own facilities. An entity can't be held responsible for developing a methodology for facilities it does not own. (8) Section 602(b)(1) states: "Responsible entities shall establish their Facility Ratings consistent with their ratings methodology, described in 601(a)." Section 601(a) does not describe any ratings methodology, it cites the requirement for a methodology. We suggest a little wordsmithing, rewriting the sentence to read: "Responsible entities shall establish their Facility Ratings consistent with their ratings methodology required by 601(a)." Response: The suggestion was implemented and is reflected in the revised standard. (9) Section 602(d): Once this standard is approved, it does not seem reasonable to expect entities to have ratings for all facilities completed immediately. There should be a reasonable period of time to allow organizations to complete facility ratings. We suggest a three-year period. Response: Agreed. This standard does not require much documentation beyond what is already required by existing operating policies and planning standards. Please review the details of the implementation plan. (10) Levels of noncompliance in section 602(e) are cumbersome. Identify whether "some" ratings were not provided would also require considerable tracking of rating information. Response: The language was added to distinguish between level 4 where none of the ratings were provided per schedule, and other levels where some of the ratings were provided per schedule.

	(11) The references to 603.1.4.4-603.1.4.4 in 603(a)(4)(iv) on page 8 should probably be changed to 603(a)(4)(i)-603(a)(4)(iv) Response: Agreed. This entire requirement has been significantly changed, so the specific recommendations for corrections to numbering are no longer relevant. (12) Please move the last sentence in section 603(a)(3)(i)(A), "Curtailment of load or transfers is not required to maintain the system within the System Operating Limits", to section 603(a)(3)(i)(B). This change would remove the potential conflict between 603(a)(3)(i)(A) and 603(a)(3)(i)(C) and allow the operators the flexibility to curtail transmission service if deemed necessary to accommodate planned maintenance. Response: Your suggestion has been addressed. (12) In section 603(a)(3)(ii) requires the evaluation of "(a) Single line to ground or 3-phase fault, with Normal Clearing, on *any* faulted Facility". The previous draft showed a Table I, which specifies "single line to ground or 3-phase fault, with normal clearing on, Generator, Transmission Circuit, or Transformer". Since "any Facility" includes more than those specified in Table I, for example, faults on bus sections, this draft appears to be more stringent than the previous version. Please replace "any faulted Facility" with "any faulted Generator, Transmission Circuit, or Transformer". Response: The standard has been revised to address your concern. 14. Please replace 603(a)(3)(iv)(e) with footnote d from Table I. Footnote d states: "Depending on system design and expected system impacts, the controlled interruption of electric supply to Customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems." Footnote (d) applies to Category C contingencies (N-1-1), which is more in line with operating studies. Response: The SDT believes that these items are already addressed in the standard. (15) In section 603(a)(3)(iv)(f) and (g), we allow interruption of firm load for operating studies, but make no mention of interruption of contracted firm transfer. This would put contracted firm transfer ahead of firm load. Please change these sections to allow for interrupting "contracted transfer" if needed. Response: The wording has been adjusted to reflect your suggestion. (16) In section 603(c)(1)(i) there is no mention of single line-to-ground faults with normal clearing on a bus section or a circuit breaker (failure or internal fault) as in the previous version of the draft. Was this intentional or was it an oversight?

	Note – per the commenter, this is a comment for NPCC's consideration and was sent to NPCC. The SDT will post the response from NPCC when it is received. (17) Section 603(e)(1) might be clearer if a parenthetical reference was made to section 603(a)(2) since that section [603(a)(2)] is also referenced in non-compliance level 3 just below in section 603(e)(3). Response: There were many suggestions for modifying this requirement to improve its clarity. In the revisions, we tried to reduce the number of cross references to try to reduce the confusion. (18) Sections 602, 604 and 606 have no requirements for periodic review and update of the ratings established in 602 – Establish and Communicate Facility Ratings, 604 – Establish and Communicate System Operating Limits, and 606 – Establish and Communicate Transfer Capabilities. To assure the ratings are still current and accurate we believe this issue should be addressed by the standard. Response: The schedule can contain a requirement that the facility rating be updated on a periodic basis or when new ratings are established. (19) In section 605(a)(2) "The methodology required in 605(a)(1) shall state that Transfer Capabilities shall adhere to all applicable System Operating Limits". Please change "adhere to" to "remain within" because as written, this section could be interpreted as the Transfer Capabilities shall be the same as all applicable System Operating Limits. Response: The standard was revised to support your suggestion

<u>Comments of Consolidated Edison:</u>

Global Change : Where it says Transmission Planning please replace it with Transmission Planning or Engineering. This change is necessary because some of the Transmission Planning organizations may not be responsible for developing the methodology for ratings. They are normally developed by the Engineering folks and sent to Planning and Operations.

Response: The requirements in all new standards need to be assigned to one or more of the functions identified in the Functional Model, therefore this suggestion was not adopted – this should not be confused with the organization in which that function resides.

Sanctions **:** We need to object to dollar penalties. If NERC disagrees then we should ask another global change stating:

"For the NPCC Region, the sanctions for non-compliance will be in accordance with NPCC criteria and procedures". According to long outstanding practice in NPCC, fixed dollar penalties are not permitted. The sanction matrix adopted in NPCC is similar to that described on Page 18 under the paragraph titled "Letter" and it has worked very well. We propose that the paragraph titled "Fixed Dollars" and "Dollar per MW" be removed along with the second half of Page 19.

Response: The SDT doesn't have the authority to modify the Sanctions Table. The Sanctions Table was adopted by the NERC Board.

Definitions : Please provide a rational for how "frequency" ratings are being developed at NERC or at the Regions.

Response: Frequency ratings are dependent on equipment limitations.

System Operating Limits-

- Since the SAR provides for System Operating Limits used by the Transmission Planner and Transmission Owner, does that preserve the use of Thunder Storm Operating Limits in New York?
- In Section 603 iv, Response to Subsequent Contingencies (operating studies only). Does this mean that studies also look at the next contingency, assuming one contingency has already occurred and the system has had time to readjust itself? See item (g)

Response: This standard doesn't eliminate any requirement to meet local or regional requirements.
Terminology, 'subsequent contingencies' is a contingency on a system that has already experienced at least one other outage.

Transfer Capabilities-

- Section 606 (a) Communication of Transfer Capabilities should make it clear that Transfer Capabilities must be communicated to other (adjacent) impacted Reliability Authorities and Transmission Operators, not just the associated Reliability Authorities and Transmission Owners.

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Response: Agreed. The terms 'associated' has been used in the standard and 'associated' refers to other than just 'adjacent' entities.

Bob Kotecha
x 3507

<u>WECC Regional Difference Request:</u>

System Operating Limits Methodology

c. Regional Differences

2. The following Regional Difference shall apply only in the Western Electricity Coordinating Council (WECC). The WECC methodology required in 603(a)(1) shall require that System Operating Limits be established for following system conditions, in addition to those listed in 603(a)(3)(i)

   i. Single Contingencies

   The following single contingencies must be evaluated:

   a. Single line to ground or 3-phase fault, with Normal Clearing, on any faulted Generator, Transmission Circuit or Transformer.

   b. Loss of any Facility without a fault.

c. Single pole block, with Normal Clearing, in a monopolar or bipolar HVdc system.

B) System Operating Limits shall be established such that for contingencies in 603(c)(2)(i)(A) operation within the System Operating Limit shall provide system performance consistent with that prescribed in 603(a)(3)(iii)–603(a)(3)(iv) above.

ii. Multiple Contingencies

A) In addition to the single Facility contingencies listed in 603(c)(2)(i)(A), the following multiple Facility contingencies must also be evaluated when establishing System Operating Limits:

a. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

b. A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in (g) below.

c. Simultaneous permanent loss of both poles of a direct current bipolar facility without an AC fault.

d. The failure of a circuit breaker associated with a special protection system to operate when required following: the loss of any element without a fault; or a permanent phase to ground fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

e. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on separate towers in a common right-of-way, with Normal Clearing.

f. A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by Standard 603.

g. The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground fault.

B) System Operating Limits shall be established such that for multiple Facility contingencies in 603(c)(2)(ii)(a)- 603(c)(2)(ii)(d) operation within the System Operating Limit shall provide system performance consistent with the following:

a. All Facilities are operating within their applicable post-contingency thermal, frequency and voltage limits.
b. Cascading outages do not occur.
c. Uncontrolled separation of the system does not occur.

d. The system demonstrates transient, dynamic and voltage stability.
e. Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
f. Interruption of firm transfer, load or system reconfiguration is permitted through manual or automatic control or protection actions.
g. To prepare for the next contingency, system adjustments are permitted, including changes to generation, load and the transmission system topology when determining limits.

C) System Operating Limits shall be established such that for multiple Facility contingencies in 603(c)(2)(ii)(e) operation within the System Operating Limit shall provide system performance consistent with the following with respect impacts on other systems:

a. All Facilities are operating within their applicable post-contingency thermal, frequency and voltage limits.
b. Cascading outages do not occur.
c. Uncontrolled separation of the system does not occur.
d. The system demonstrates transient, dynamic and voltage stability.
e. Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
f. Interruption of firm transfer, load or system reconfiguration is permitted through manual or automatic control or protection actions.
g. To prepare for the next contingency, system adjustments are permitted, including changes to generation, load and the transmission system topology when determining limits.

D. System Operating Limits shall be established such that for multiple Facility contingencies in 603(c)(2)(ii)(f) – 603(c)(2)(ii)(g) operation within the System Operating Limit shall provide system performance consistent with the following with respect to impacts on other systems:

a. Cascading outages do not occur.

E. When planning systems and facilities, WECC may make changes (performance category adjustments) to the contingencies required to be studied and/or the required responses to contingencies based on actual system performance and robust design. Such changes will apply in determining System Operating Limits.