Consideration of Comments

TPL Table 1 Order – Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revision of TPL-002 footnote 'b' and TPL-001 footnote 12. These standards were posted for a 30-day public comment period from July 31, 2012 through August 29, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 117 different people from approximately 81 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

Due to comments received, the SDT has made the following changes to the text:

- Effective date – updated to latest approved language
- Main footnote
    - Grammatical change from 'should be' the intent to 'is' the intent.
    - Clarified the near-term and long-term requirements.
    - Defined the ceiling threshold as 75 MW.
- Attachment 1
    - Section I
        - Clarified that an existing process can be utilized, as long as it meets the criterion in Section I.
        - Changed 'all affected stakeholders' to 'affected stakeholders'.
        - Changed 'specific applications' to 'specific locations'.
        - Added statement that says that the process does not have to be repeated in subsequent years if conditions haven't changed.
    - Section II
        - Item 2.b has been clarified to better show the SDT's intent.
        - Item 8 has been changed from 'planners' to 'Transmission Planners and Planning Coordinators and clarified to indicate that it includes both the local and adjacent entities.
    - Section III
        - Clarified role of regulatory authority.
        - Deleted role of Regional Entity.
        - Defined the ceiling threshold as 75 MW.
- Footnote 12 only – Corrected terminology to use 'Non-Consequential Load loss' instead of 'Firm Demand interruption'.

The SDT is requesting that this project be moved forward to the initial ballot and comment phase of the process.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. Do you agree with the description and components of the the Stakeholder Process in the body of the footnote including the maximum capacity threshold (currently shown as 'x' MW but the SDT will fill in the value after the data request is complete and will submit the value for industry comment and approval in the next posting)? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity. 11
2. Do you agree with the description and components of the the Stakeholder Process in Section I of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 33
3. Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 53
4. Do you agree with the Instances for which Approval of Interruptions is required in Section III of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 72
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The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Sunitha Kothapalli	Puget Sound Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph (Joe) W Seabrook	Transmission Contracts	WECC	1, 3, 5
2.	Peter (Pete) M Jones	Transmission Contracts	WECC	1, 3, 5
3.	Kebede Jimma	Transmission Planning	WECC	1, 3, 5
4.	Gary Shumate	Transmission Planning	WECC	1, 3, 5
5.	Harris Wayne	Transmission Planning	WECC	1, 3, 5
6.	Carol Jaeger	Transmission Planning	WECC	1, 3, 5
7.	Zachery (Zach) Sanford	Transmission Planning	WECC	1, 3, 5
8.	Eleanor Ewry	Transmission Planning	WECC	1, 3, 5

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

3. Group	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Harold Wyble	Kansas City Power and Light Company	SPP	1, 3, 5, 6
6.	Katy Onnen	Kansas City Power and Light Company	SPP	1, 3, 5, 6
7.	Don Taylor	Westar	SPP	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Bob Steiger	Salt River Project	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Keel	SRP	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALT	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Bob Jones	Southern Company Services	SERC	1
3.	Pat Huntley	SERC	SERC	NA
4.	Darrin Church	TVA	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Jason Marshall	ACES Power Member Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ashley Gonyer	East Kentucky Power Cooperative	SERC	1, 3, 5
2.	Noman Williams	Sunflower Electric Power Corporation	SPP	1
3.	David Albers	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck	Matthews	WECC	1
2.	Allen	Chan	WECC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering & Controls	X		X		X	X			X	
10.	Individual	Antonio Grayson	Southern Company										
11.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
12.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
13.	Individual	Aaron Staley	Orlando Utilities Commission	X									
14.	Individual	Chifong Thomas	BrightSource Energy, Inc.					X					
15.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
16.	Individual	Mark Westendorf	MISO		X								
17.	Individual	Jennifer Wright	San Diego Gas & Electric	X		X		X					
18.	Individual	Patrick Brown	Essential Power, LLC					X					
19.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
20.	Individual	John Burnett	Los Angrles Department of Water and Power	X		X		X					
21.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
22.	Individual	Michael Falvo	Independent Electricity System Operator		X								
23.	Individual	Kirit Shah	Ameren	X		X		X	X				
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	John Delucca	LCEC (Lee County Electric Cooperative	X		X							
26.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
27.	Individual	James Tucker	Deseret Generation & Transmission Cooperative	X		X		X					
28.	Individual	Brian Keel	Salt River Project	X		X		X	X				
29.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
30.	Individual	Anthony Jablonski	ReliabilityFirst										X
31.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
32.	Individual	Milorad Papic	Idaho Power Co.	X		X							
33.	Individual	Martyn Turner`	LCRA Transmission Services Corporation	X									
34.	Individual	Jonathan Fidrych	Tri-State Generation & Transmission Association, Inc.	X		X		X					
35.	Individual	John Martinsen	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
36.	Individual	Robert W. Creighton	Nova Scotia Power	X									
37.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
38.	Individual	Chris de Graffenried	Consolidate Edison Co. of NY, Inc.	X		X		X	X				
39.	Individual	Charlie Pottey	Sierra Pacific Power Co d/b/a NV Energy	X		X		X					
40.	Individual	Richard Vine	California Independent System Operator		X								
41.	Individual	charlie pottey	nevada power company dba nvenergy	X		X		X					
42.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
43.	Individual	Chris Scanlon	Exelon	X		X		X	X				
44.	Individual	Catherine Mathews	NorthWestern Energy (NWMT)	X		X		X					
45.	Individual	Robert Casey	Georgia Transmission Corporation	X									
46.	Individual	Kathleen Goodman	ISO New England Inc.		X								
47.	Individual	Bangalore Vijayraghavan	PG&E Company	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
48.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
49.	Individual	Steve Myers	Electric Reliability Council of Texas, Inc.		X								
50.	Individual	Ed O'Brien	Modesto Irrigation Districtt			X	X		X				
51.	Individual	R. Peter Mackin	Utility System Efficiencies, Inc.								X		

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: Thank you for following the new method of commenting that helps to avoid needless duplication of effort for the SDT. Your company name will be included in the participant list and the comments in full will be reviewed by the drafting team members under the Salt River Project comment/response.

Organization	Yes or No	Support Comments Submitted by Another Entity
Puget Sound Energy	Agree	Salt River Project
Sierra Pacific Power Co d/b/a NV Energy	Agree	WECC

1. **Do you agree with the description and components of the Stakeholder Process in the body of the footnote including the maximum capacity threshold (currently shown as 'x' MW but the SDT will fill in the value after the data request is complete and will submit the value for industry comment and approval in the next posting)? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.**

Summary Consideration: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Several commenters suggested that there should be no limitation on the amount of Load that could be shed under footnote 'b'. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.

Several commenters asked about the distinction between long-term and near-term with respect to the use of footnote 'b'. The SDT has clarified the language to show that footnote 'b' is available for long-term planning as well as near-term planning but that the stakeholder process only needs to be used for near-term.

The following changes were made due to industry comments:

First sentence of footnote text: An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.

Next to last sentences in footnote text: In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Organization	Yes or No	Question 1 Comment
Salt River Project BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative California Independent System Operator nevada power company dba nvenergy PG&E Company Utility System Efficiencies, Inc.	No	We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence.Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others.A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.

Organization	Yes or No	Question 1 Comment
ACES Power Member Standards Collaborators	No	We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by such a data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation?
Bonneville Power Administration	No	BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. As stated in the proposed footnote b, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events." Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases. Moreover, a quantitative limit would be difficult to implement due to the wide variety of system configurations and conditions. BPA believes an appropriate amount would be dependent on the topography and the size of the system being planned.
Manitoba Hydro	No	The maximum limit 'x' MW should vary with system load level and voltage. For example, an 'x' MW interruption would be a very small fraction of a 5000 MW system load level compared to a 1000 MW load level. Similarly, interruption of 'x' MW could be equal to surge impedance loading of a 230 kV line, where as it would be a fraction of a EHV transmission line loading.
NorthWestern Energy (NWMT)	No	Comments: A fixed maximum number of MW for Non-Consequential Load

Organization	Yes or No	Question 1 Comment
		Loss should not be used in an industry-wide standard. There is too much diversity. We suggest that a fixed maximum number not be stipulated.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
SERC EC Planning Standards Subcommittee	No	We do not agree with this approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. If a single contingency results in a local network becoming temporarily radial, then load shedding within the local network should be allowed. A limitation of up to some maximum amount of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency.
Southern Company	No	Southern does not agree with this Stakeholder Process approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. A more technical based approach was the one taken by the SDT in an earlier draft - temporarily radial concept. If a single contingency (Category B) results in a local network becoming temporarily radial, then load shedding within the local network should be allowed since it would not have any impact to the reliability of the transmission grid. A limitation of up to some maximum amount ('x' MW) of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency from area to area. Furthermore, this would provide a method for defining the "fringes" of the power system.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed		

Organization	Yes or No	Question 1 Comment
Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees with you that there should be an upper limit on the amount of Firm Demand that can be shed. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
TVA Transmission Reliability Engineering & Controls	No	TVA believes that the Stakeholder process is burdensome and should not be required for all levels of footnote b use. TVA beleives that the Stakeholder process should only be used for larger amounts of planned load drop. TVA would like to propose the following: For load loss of less than 50 MW - only TP approval is required; for load loss up to 100 MW - PC approval is required; for load loss up to 300 MW - RRO approval is required. Any load loss over 300 MW would require both RRO & NERC approval. The Stakeholder process would be required for any load loss of 100 MW or more. TVA is basing these levels using OE-417 as a starting point - which must be filed for an uncontrolled load loss of 300 MW as well as load shedding of 100 MW or more implemented under emergency operational policy. TVA believes that the 300 MW is the maximum amount of load that can be dropped without obtaining special permission from both NERC and the RRO.
Response: The SDT does not agree with this suggestion, as the Order 762 data request showed that there were no utilizations of		

Organization	Yes or No	Question 1 Comment
footnote 'b' involving more than 75 MW. Therefore, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. The data request also showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW.		
MISO	No	Transmission planning that relies on planned or controlled interruption of non-consequential firm load following loss of a single transmission facility should not be acceptable and removal of footnote 12 should be considered or a modification to allow its use only in conjunction with a petition to FERC to waive (on an exception basis) the requirement to maintain firm load service for a specifically identified system configuration issue warranting Footnote 12's application. If it is determined that a footnote provision is required in the standard, we agree with the description and components of the Stakeholder Process in the body of the footnote, but reserve judgment on the value of the "x" that sets the maximum amount of MW load loss. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		

Organization	Yes or No	Question 1 Comment
See response to Q5.		
San Diego Gas & Electric	No	We don't support the changes.
Public Utility District No. 1 of Snohomish County	No	
Response: Without any reasons being supplied, the SDT is unable to respond to this comment.		
Essential Power, LLC	No	Although we agree with the majority of the content of the footnote, we're not sure that using a specific amount of load as the bright-line threshold is appropriate. For example, if we make the limit 25 MW, this will have a different impact on different entities, in different regions. For a small TP that may only have a total of 200 MW of load, 25 MW is a significant amount of their overall obligation. For an area with 40,000 MW of load, 25 MW is hardly significant. Additionally, the nature of the load must be taken into consideration as well. Some types of load are more acceptable to lose than others; again, this may vary from region to region.Although we don't have a specific recommendation or solution regarding these issues, I would urge the SDT to take these into consideration in their next revision. The sentence that starts with "When interruption of Firm Demand is utilized..." is confusing as it seems this sentence should only refer to the limited circumstances mentioned within footnote b
Response: The Order 762 data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made. The SDT believes that in context the sentence you reference is clear; no change made.		
Tacoma Power	No	The layout of Table 1 with "No 12" does not actually indicate that load loss is allowed for those specific contingencies. Also the wording of the

Organization	Yes or No	Question 1 Comment
		footnote appears to require all Non-Consequential Load Loss to go through the attachment 1 process, not just P1.1 to P1.5, P2.1 and P3.1 to P3.5. Instead P1.1 to P1.5 and P3.1 to P3.5 should say “Yes per Attachment I” and Footnote 12 should be eliminated entirely. Since P2.1 is a new requirement with Version TPL-001-03, the recent NERC survey did not capture utilities currently using Non-Consequential Load Loss to address opening a line without a fault. Furthermore, some utilities may not identify problem lines until their first assessment using TPL-001-3. P2.1 should have a new footnote reading “For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential load.” Technical Background: Parallel transmission lines serving remote load commonly will not perform with a P2-1 contingency, particularly when the strong source is opened. These issues are particularly common with load in rural settings and the cost to meet urban reliability expectations will be disproportionally expensive. Utilities will be encouraged to configure their system radially, which will be less reliable to meet this rare contingency. FERC has not specifically addressed load shedding associated with open ended lines. In order 693 the Commission was responding to the contingencies in TPL-001-1 that included footnote b. In order 762 and the NOPR RM12-1-000, FERC continues to reference applicability of footnote b to the TPL-001 defined single contingencies, but was otherwise prepared to accept Firm Load Loss for the single contingencies in TPL-001-2 P2.2 to P2.4. In the TPL-001-2, the category of “P2-Single Contingency” expanded to include both a new contingency of an open ended line, and various bus and breaker faults that previously were considered as Multiple Contingency.Based on our experience the likelihood of a line opening is significantly less than for line equipment faults. In addition, during human error caused line open events, personnel are on-site to affect quick restoration. This standard should not impose an upper limit because any planned large

Organization	Yes or No	Question 1 Comment
		load shedding will be reviewed and approved by the applicable regulatory authority. Pending the survey outcome, a limit of 3000 MW consistent with the CIP-002-5 Critical Asset level may be useful if the SDT believes an upper limit is needed.
Response: The SDT believes that the layout of Table 1 is clear in its intent that the circumstances covered by footnote 12 permit Load loss by exception and that the footnote pertains only to those Contingency types where the footnote appears. No change made. Although P2.1 is a "new" event, the resulting system will be the same as that following many P1.2 events; therefore, the SDT does not see a need to add a new footnote to P2.1. No change made. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Independent Electricity System Operator	No	Specific to the language used in footnote b, we agree with the concept of an approval process for determining the acceptable level of Firm Demand interruption applicable in a jurisdiction, and do not agree with prescribing a fixed MW threshold for a continent-wide acceptable Firm Demand interruption.Therefore, we recommend removing the last sentence in footnote b) which reads "In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW." and also the same sentence from Attachement 1 section III. We believe there should not be a fixed limit on the amount of Firm Demand interruption, for reasons explained below in answers to Questions 4 and 5. As part of a reliability standard, the footnote should clarify the conditions under which load curtailment will be allowed, including mention of processes necessary to manage special circumstances. We generally agree with the reference to Attachment 1, but have concerns

Organization	Yes or No	Question 1 Comment
		about the components of the Stakeholder Process described in Attachment 1, for reasons described in answers to Questions 2, 3 and 4.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. See responses to Questions 2, 3, 4, and 5.		
Ameren	No	We believe that the NERC Glossary contains an adequate definition for Firm Demand, which does not include Interruptible Demand or Demand-Side Management Load. We do not believe that Interruptible Demand or Demand-Side Management Load needs to be mentioned in the footnote b) as these types of Demand are not Firm Demand. Interruptible Demand can be cut at any time and may contain Demand-Side Management components, and may be direct controlled by the System Operator.
Response: The SDT believes that mention of Interruptible Demand and Demand-Side Management Load within footnote 'b' adds further clarity. No change made.		
American Transmission Company	No	ATC agrees with the 'x' MW statement in footnote 'b' , however, supports a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.
Response: The SDT does not agree with this suggestion. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Salt River Project	No	Additional comment from SRP for Q #5.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Consolidate Edison Co. of NY, Inc.</td><td>No</td><td>See reply to Question 5</td></tr>
<tr><td colspan="3">Response: Please see response to Q5.</td></tr>
<tr><td>Lincoln Electric System</td><td>No</td><td>LES suggests the following changes to Footnote B/12 to further clarify the drafting team’s intent. Under Footnote B/12, recommend the first sentence be modified to state “An objective of the planning process is to minimize the likelihood and magnitude of interruption...”.

Additionally, please clarify the reference to the Near-Term Transmission Planning Horizon while remaining silent on the Long-Term Transmission Planning Horizon. Does Appendix 1 apply to the Long-Term Transmission Planning Horizon as well as the Near-Term Transmission Planning Horizon?</td></tr>
<tr><td colspan="3">Response: The SDT agrees with your suggested substitution of the word “is” for the words “should be” in the first sentence of the footnote.

An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.

The SDT has clarified the language to show that footnote ‘b’ is available for long-term planning, as well as near-term planning, but that the stakeholder process only needs to be used for near-term.

In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.</td></tr>
<tr><td>LCRA Transmission Services Corporation</td><td>No</td><td>Footnote 12 is applied in column labeled “Non-Consequential Load Loss Allowed.” However, the last sentence of the proposed Footnote 12 switches from using the terms Consequential Load Loss and Non-Consequential Load Loss to using the term “Firm Demand.” The term “Firm Demand” should be revised to “non-Consequential Load Load loss.”</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		In addition, the application of Footnote 12 to the P3 contingency category should be removed.
Response: The SDT agrees with your change and will use the term "Non-Consequential Load loss." The SDT does not agree that footnote 12 should be removed from the P3 Contingency category. The SDT clarifies that the Planning Events for which footnote 12 is applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Tri-State Generation & Transmission Association, Inc.	No	There are several points that we disagree with in terms of the Stakeholder Process in the body of the footnote. First, the footnotes are not written in a manner so as to clearly be only applicable to Planning Standards. Many parts of the footnotes and the Attachment I can be misconstrued as Operational requirements. For example, the sentence that states "Curtailment of firm transfer..." should state "Planned curtailment of firm transfer..." Second, we disagree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest removal of this sentence.Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others.A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed

Organization	Yes or No	Question 1 Comment
		maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Lastly, in an effort to develop a clearer and more transparent compliance standard, it is recommended that the additional requirements imposed by this footnote be broken into separate requirements set forth within the body of the standard itself. Do not imbed requirements in footnotes.
Response: Because this footnote can only be applied to this specific standard, there should be no confusion as to the applicability to planning. No change made. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. The SDT disagrees with your characterization that requirements are being imbedded within the footnote. The requirement is clearly stated within the body of the standard. The footnote is simply clarifying those special circumstances where some relief from a strict interpretation of the requirement is permitted. No change made.		
Hydro-Quebec TransEnergie	No	Comments: It is difficult to establish the maximum value for acceptable Firm Demand interruption. For example, an entity may have an acceptable maximum load loss to avoid impacts on the grid such as generation trip-outs. For Hydro-QuÃ©bec TransÃ‰nergie (HQT), in the QuÃ©bec Interconnection, this value is above 1,000 MW. No maximum value should be posted in Footnotes 12 and 'b', since it is specifically related to system design and Interconnection size (inertia). Let us keep in mind that the goal of the TPL standards is not service continuity of local loads but global reliability of the system. Even though service continuity is important, TPL

Organization	Yes or No	Question 1 Comment
		standards should not address this issue by posting a maximum allowable load loss. Moreover, HQT considers that a Stakeholder Process such as seen in Attachment I has no place in a standard and its footnotes. Mainly, the Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish this load loss value.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. Industry and the NERC BOT have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The SDT is now attempting to address FERC's concern expressed in their Remand Order 762 that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process, is vague, unenforceable, and not responsive to the previous Commission directives on this matter. The draft posted for comment adds detail and specificity to the already-approved approach. The SDT does not believe it appropriate to move away from the industry and BOT approved Stakeholder Process approach. No change made.		
Exelon	No	For TPL-001, the wording for footnote 12 does not make clear that DSM would be allowed without the Attachment 1 procedure. ComEd suggests the following wording change:12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements (other than Interruptible or Demand Side Management load), such interruption is limited to circumstances where the Non-Consequential

Organization	Yes or No	Question 1 Comment
		Load Loss is meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW. For TPL-002, the wording of footnote "b" is not totally clear that it applies only to non-consequential load shed and not consequential load shed. ComEd suggests that the wording of footnote "b" be changed as shown:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand (other than in (1) or (2) above) is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW.
Response: The SDT believes that footnote 12, as written and taken in context of the entire proposed TPL-001-2a standard, is clear. Similarly, the SDT believes that footnote 'b' is clear, as well. No change made.		
ISO New England Inc.	No	For single contingency events, footnote 12 should be eliminated. Planning the electric system for non-consequential load loss as a means to address a single contingency should not be acceptable. If the footnote is to remain, as a minimum the attachment should be

Organization	Yes or No	Question 1 Comment
		changed to increase the emphasis on the near term nature of the use of non-consequential load shedding.

Response: The SDT disagrees with your suggestion to remove footnote 12 because there are some limited situations when considering the entire North American grid where Non-Consequential Load loss may be necessary. No change made.

The SDT has clarified the language to show that footnote ‘b’ is available for long-term planning, as well as near-term planning, but that the stakeholder process only needs to be used for near-term.

> In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Organization	Yes or No	Question 1 Comment
South Carolina Electric and Gas	No	SCE&G does not agree with the proposed modifications to footnote b. SCE&G believes the original footnote b is appropriate and consistent with the Energy Policy Act of 2005.SCE&G cites several statements in the Energy Policy Act of 2005 as justification for our position.1. The Energy Policy Act of 2005 states: “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity."It also states, “This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.”SCE&G believes the proposed modifications to footnote b will result in building or enlarging facilities to meet the proposed requirements.

Organization	Yes or No	Question 1 Comment
		Also, any requirement that disallows load interruption or limits the amount of load interruption infringes on the stated limitation on the ERO to not set and enforce compliance with standards for adequacy.2. It also states: The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."In this statement there is no mention of disallowing the interruption of firm load. It only requires that instability, uncontrolled separation, or cascading failures not occur. SCE&G believes the proposed changes to footnote b are beyond the authority granted to the ERO by the Energy Policy Act.3. It also states: ''Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, ..."SCE&G believes the proposed modifications to footnote b infringe on the state's authority to address adequacy and reliability of electric service within the State.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.

Organization	Yes or No	Question 1 Comment
Electric Reliability Council of Texas, Inc.	No	As an initial matter, ERCOT does not believe the planning process should allow for non-consequential load shedding under single contingency conditions. However, if the SDT elects to retain a vehicle for such exceptions, it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the “what”, not the “how”. If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. In no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards. Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements)...and, to make it worse, the

Organization	Yes or No	Question 1 Comment
		attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.

The SDT disagrees with your characterization that requirements are being imbedded within the footnote. The requirement is clearly stated within the body of the standard. The footnote is simply clarifying those special circumstances where some relief from a strict interpretation of the requirement is permitted. No change made.

Organization	Yes or No	Question 1 Comment
Modesto Irrigation Districtt	No	We do not agree with the concept of non-consequential load loss in light of historic application of N-1 criteria, that only provides for consequntial load loss.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability

Organization	Yes or No	Question 1 Comment
would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	As a concept we agree with the stakeholder process. We would like clarification on why only the Near Term was used for non-consequential load loss and not both Near and Long term. It seems that depending on the time frame we would be held to different requirements of the standard.
Response: The SDT has clarified the language to show that footnote ‘b’ is available for long-term planning, as well as near-term planning, but that the Stakeholder Process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
MRO NSRF	Yes	The NSRF agrees with the ‘x’ MW statement in footnote b. The NSRF suggests a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.To support the inclusion of planning to use up to 300 MW of firm load shedding, registered Transmission Planning entities or regional planning entities should provide a TPL type analysis that demonstrates the use of planned firm load shedding allows BES equipment to stay within emergency thermal, voltage, and frequency ranges, and would not cause instability, uncontrolled separation, and cascading as defined in the FPA Section 215.
Idaho Power Co.	Yes	Maximum threshold for Planned Firm Demand interruption should be based on a previous year recorded peak demand. For instance for recorded peak demand of more than 3,000 MW the maximum treshold should be

Organization	Yes or No	Question 1 Comment
		greater than 300 MW.
Duke Energy	Yes	Situations where use of footnote 'b' would be appropriate can't be readily characterized with criteria leading to some "technically justified" maximum capacity threshold for interruption. That being the case, a maximum capacity threshold could be established based upon other criteria, such as the 300 megawatt threshold for DOE disturbance reporting.
Response: The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Georgia Transmission Corporation	Yes	Please remove the "is" as shown below:"12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss [IS] meets the conditions shown in Attachment 1. In no case can the planned FirmDemand interruption under footnote 12 exceed 'x' MW."
Response: The SDT agrees with your suggested substitution of the word "is" for the words "should be" in the first sentence of the footnote. An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.		
LCEC (Lee County Electric Cooperative		"No comment as we have no Firm Demand / Load customers."
American Electric Power	Yes	AEP believes it can support the language at this stage, but would like to

Organization	Yes or No	Question 1 Comment
		revisit this after the MW threshold has been determined.
Arizona Public Service Company	Yes	
Orlando Utilities Commission	Yes	
CPS Energy	Yes	
City of Austin dba Austin Energy	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

2. **Do you agree with the description and components of the the Stakeholder Process in Section I of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments raised several concerns on the following issues:

Stakeholder process is not needed: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Proposed process duplicates or conflicts with existing regulator/RTO processes: The SDT agreed with the comments and revised Footnote 12 accordingly. The text now allows for an existing process to be utilized, as long as it meets the criterion set out in Attachment 1, Section I.

Scope of Stakeholder Participants: Some comments reflected concern that the term "all affected stakeholders" in Attachment 1, Part I was too broad. The SDT has accepted the commenters' view and has deleted 'all'.

Clarification on need for annual Stakeholder Review: Commenters requested clarification as to whether the stakeholder processes has to be repeated for each annual assessment for a project if the process has confirmed for that specific project it is acceptable to curtail a firm demand. The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed.

Part I 2 b. Public Notification: The SDT agrees with the comment that: "Specific applications of the planned Firm Demand interruption under footnote 12" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b' and is not necessary for the public notification. The language has been changed to clarify the SDT's intent.

Implementation Plan: Several commenters mentioned that this process could turn out to be lengthy and that the Implementation Plan should take this into account. The Implementation Plan for this project hasn't changed from the one that was submitted with the original filing, and is currently set at 60 months for footnote 'b'.

Dispute resolution process is not required: The SDT concluded that a dispute resolution process is an essential part of the process. The attachment language does not present any constraints on such a process; it just requires that an entity has a method to resolve disputes.

The following changes were made due to industry comments:

Main Body of footnote text: In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Attachment 1 – Section I, last sentence: The responsible entity can utilize an existing process or develop a new process. The process must include the following:

Attachment 1 – Section I, Bullet 1: Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

Attachment 1 – Section 1, Bullet 2: Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

Attachment 1 – Section I, Bullet 2b: Specific location(s) of the planned Firm Demand interruption under footnote 'b'

Attachment 1 – Section I, last paragraph: An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

Organization	Yes or No	Question 2 Comment
Salt River Project	No	We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction".

Organization	Yes or No	Question 2 Comment
BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative nevada power company dba nvenergy PG&E Company Modesto Irrigation District Utility System Efficiencies, Inc.		Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
Response: The SDT believes that a dispute resolution process is an essential part of the Stakeholder Process. The SDT believes that the dispute resolution process should include a method for accounting for the cost/benefit if it is an issue for the region. The attachment language does not present any constraints on such a process; it just requires that an entity has a method to resolve disputes. No change made.		
MRO NSRF American Transmission Company	No	Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote 'b'. In additions, there is no clear justification to indicate that the process with regard to footnote 'b' warrants more prescription stakeholder process details than the rest of the TPL standards. So, the NSRF suggests that Section II be removed. If Section I is not removed, then NSRF suggests at least replacing "all affected stakeholders" with "all known affected stakeholders" or "appropriate known affected stakeholders" because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open

Organization	Yes or No	Question 2 Comment
		to unknown stakeholders or that it notified unknown stakeholders.The use of “all” in mandatory zero defect standards is not appropriate in NERC standards, especially when potential large diverse populations such as affected stakeholders must be considered.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote ‘b’ and with footnote 12 in TPL-001-2. The Commission’s Order No. 762 found that NERC’s proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT has tried to provide some technical/quantitative criteria in Section II to assist affected stakeholders in understanding why Firm Demand is planned to be interrupted. No change made. The SDT has accepted your comment and has replaced “all affected stakeholders” with “affected stakeholders.” Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:		
TVA Transmission Reliability Engineering & Controls	No	Please see comment for question #1. TVA believes that TPs should be able to drop some load without having to go thru a burdensome process. Only the larger load drop levels should require a Stakeholder review.
SERC EC Planning Standards	No	We recommend using a technical basis for load shedding instead of a Stakeholder

Organization	Yes or No	Question 2 Comment
Subcommittee		Process.
Southern Company	No	Southern recommends using a technical basis for load shedding (see comment in Question 1 above) instead of a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. Please also see response to Q1.		
ACES Power Member Standards Collaborators	No	(1) Attachment 1 should clarify that it only applies when approval is not required by the regulatory body with authority over retail service, such as local regulatory authorities and state public utility commissions. This includes whether the approval is required by NERC rules or another regulatory body's rules. It does not make sense for the Transmission Planner or Planning Coordinator to duplicate a process that is already required by another regulatory body that satisfies due process. As an example, why should the Transmission Planner and Planning Coordinator have a dispute resolution process if the regulatory body already has a dispute resolution process that can be used. It also does not make sense for the Transmission Planner and Planning Coordinator to be compelled to have a stakeholder comment process when the local regulatory body's approval is required. Having such a process is duplicative and unnecessary.

Organization	Yes or No	Question 2 Comment
		(2) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment I. Because the TPL standards apply to both the PC and TP, one may believe the both the PC and TP need to have these stakeholder processes. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We suggest Attachment I should clarify that this is acceptable and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
Response: The SDT has revised the Stakeholder Process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following: The SDT believes that a dispute resolution process is an essential part of the stakeholder process. No change made.		
Bonneville Power Administration	No	Regarding the stakeholder process and dispute resolution, BPA believes that a decision for Firm Demand interruption needs to be made based on what is best for the system, not a specific dispute resolution process.
Western Area Power Administration	No	The addition of the "Stakeholder Process" outlines in Attachment 1 is so onerous so as to persuade entities NOT to attempt the use of Footnote b) OR 12). Is this the intent?
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does		

Organization	Yes or No	Question 2 Comment
not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
MISO	No	(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed or approved by the Regional Entities (since the RE will eventually need to review and assess the reliability impact of such utilization), with supporting information. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term". (3) Requirement 8 of the Transmission Planning Standard TPL-001-3 requires notification and response requirements for a Planning Coordinator and/or Transmission Planner for the Planning Assessment to any registered entity having a reliability interest. Attachment I does not recognize this requirement. Attachment I must be coordinated with this administrative requirement.
Response: (1) Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission		

Organization	Yes or No	Question 2 Comment
remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. (2) The Stakeholder process is required prior to planned interruption of Firm Demand in the near term, but does not preclude application in the long term. The SDT clarified the language concerning near- and long-term applications of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. (3) Requirement R8 imposes an obligation on the Planning Coordinator and Transmission Planner to distribute its Planning Assessment to: "any functional entity that has a reliability related need and submits a written request for information …" Requirement R8 does not ensure the functional entity is aware that it may be affected by a plan to curtail firm Load so as to request information. If a Planning Coordinator or Transmission Planner has established a stakeholder process, as per Attachment 1, reporting of such a process under Requirement R8 is not prohibited. No change.		
Public Utility District No. 1 of Snohomish County	No	
San Diego Gas & Electric	No	We don't support the addition of stakeholder process language.
Response: With no reasoning provided, the SDT is unable to respond to this comment.		
Tacoma Power	No	Completing the entire stakeholder process on an annual basis, before the TPL study can be finalized, is not feasible due to long and unpredictable timelines for public involvement and regulatory approval. The stakeholder process should only be repeated when the technical basis as outlined in section II have changed, or when

Organization	Yes or No	Question 2 Comment
		there are new stakeholders. There are cases on the fringes of the system where Firm Demand Interruption as the preferred alternative in both the long term and short term, not as a temporary patch in Corrective Action Plan.To address these issues, Section I should read as:Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of this mitigation is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:1. Meetings must be open to all affected stakeholders including applicable regulatory Authorities or governing bodies responsible for retail electric service issues. 2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: a. Date, time, and location for the meeting b. Specific applications of the planned Firm Demand interruption under footnote 12 c. Provisions for a stakeholder comment period 3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants. 4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns. 5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction. During each Planning Assessment, the Transmission Planner or Planning Coordinator shall update the information outlined in Section II. If the annual hours of exposure to or the amount of Firm Demand has increase above the previously disclosed level(s), a new Stakeholder process shall be completed within one Calendar year.Every three years the stakeholder process shall reoccur to allow new stakeholders input to the process.
Response: The SDT has not adopted your proposed language: “Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment,” as the SDT believes the reference to the Corrective Action Plan is		

Organization	Yes or No	Question 2 Comment
superior. However, the SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has already provided a 60-month implementation plan. No change made. The information in Section II is required as part of the Stakeholder meeting. No change made.		
Manitoba Hydro	No	A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation. If Firm Demand interruptions require the approval of regulatory authority as described in Section III (for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV), the stakeholder process described in Section I would become a redundant process. Does Section I exclude Firm Demand interruptions addressed under Section III?
Response: The SDT has revised the stakeholder process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following For interruptions over 25 MW, or if voltage level of the Contingency is greater than 300 kV, then both the Stakeholder Process and the Section III regulatory review are still required.		
Independent Electricity System Operator	No	(1) The process presented in Section I and the rest of Attachment I is overly prescriptive and lengthy. As part of a reliability standard, the footnote and process must focus on the impact that Firm Demand interruption (or Load Rejection) would

Organization	Yes or No	Question 2 Comment
		have on the reliability of the Bulk Electric System and this aspect is covered in Section III. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through (a) an open and transparent stakeholder process and (b) approved by a relevant reliability authority such as the ERO, Regional Entity or applicable governmental authority since this authority will eventually need to review, assess and approve the reliability impact on the interconnected BES of such utilization, with supporting information. Reliability issues and their assessment and approvals should be dealt with by the applicable reliability authority. Details of other aspects of Firm Demand interruption, mainly the Stakeholder review and approval process and issues pertaining to the quality of service, economic and welfare impacts of Firm Demand interruption, assessment of alternatives (including their economic and welfare impacts), etc. should be dealt with by the regulatory authority or government body of each jurisdiction (in particular, in non-US jurisdictions), as is the normal practice for all other Transmission Planning activities. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholders' and regulatory authorities' approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: (1) The SDT believes that the stakeholder process must involve all stakeholders affected and provide specific information of the intended purpose and scope so they can understand the reason for Firm Demand interruption is appropriate. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability		

Organization	Yes or No	Question 2 Comment
Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has provided a 60-month implementation plan. (2) The Stakeholder process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
Ameren	No	We request that Item 1 be modified to include representatives of stakeholders because it may not be practical to open a meeting to all affected stakeholders. The new sentence of Attachment 1 should read, "Meetings must be open to all affected stakeholders, or their representatives, including applicable regulatory authorities or governing bodies responsible for retail electric service issues." Also, requirements for a meeting location would sem to eliminate electronic partipation via webex. It would seem more practical for a TP or PC to host a specific webex to present and discuss the issues associated with the need to drop Firm Demand. Further, we request that a MW threshold be included before the Section I stakeholder process would begin, and believe that a minimum threshold of 10 MW of Firm Demand to be cut would be a reasonable value to initiate a stakeholder process.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>Levels below 10 MW would be considered as “noise” in the planning horizon. We believe that an approval should be obtained in the Section I process, which would eliminate the need for Section III. By requiring an approval of the appropriate local governing bodies responsible for retail service issues (including rates), there is no need to agree on a cap to limit the amount of Firm Demand dropped.</td></tr>
<tr><td colspan="3"> Response: The SDT agrees that the term “all affected stakeholders” in Attachment 1, Part I is too broad. The SDT has accepted the commenters’ view and has replaced “all affected stakeholders” with “affected stakeholders.” The SDT has not included stakeholder representatives, as this too would make identification of same impossible.
<blockquote>Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues</blockquote>
<blockquote>Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:</blockquote>
The Stakeholder Process in Attachment 1 assumes that a meeting would be held; however, the language does not prohibit the use of other methods acceptable to the stakeholders.
Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote ‘b’ and with footnote 12 in TPL-001-2. The Commission’s Order No. 762 found that NERC’s proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. </td></tr>
<tr><td>Consolidate Edison Co. of NY, Inc.</td><td>No</td><td>See reply to Question 5</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
LCRA Transmission Services Corporation	No	In the Proposed Revision to the Standard, Footnote 12 is applicable to the use of Non-Consequential Load Loss to relieve criteria violations resulting from P1, P2, and P3 category contingencies, however, Footnote 12 and Attachment I switch terms and begins using “Firm Demand.” Though it may be reasonable to characterize Non-Consequential Load Loss as a subset of Firm Demand not all Firm Demand is Non-Consequential Load Loss. The term “Firm Demand” as used in Footnote 12 and Attachment I should be replaced with “Non-Consequential Load Loss.” Application of the term “Firm Demand” in Footnote 12 and Attachement 1 introduces an ecomonic criteria to the TPL-001 Reliability Standard. For intstance, the interruption of “Firm Demand” as defined in the NERC Glossary may not require Non-Consequential Load Loss, however, this is an economic decision between the parties involved in the Firm Demand contract. In addition, a Transmission Planner or Tranmission Owner may or may not be a party to the Firm Demand contract. The process outlined in Attachment 1 applies to the P3 contingency category (through the application of Foontote 12) and thus represents a significant and substantive change in the reliability standard over previous standards. The reference to Footnote 12 should be deleted from the P3 contingency category.
Response: The SDT acknowledges that the references to Firm Demand interruption should reference Non-Consequential Load Loss. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes. The SDT clarifies that the planning events for which footnote 12 is applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Tri-State Generation &	No	We disagree with Section I of Attachment I to the extent that there currently are several other venues through which stakeholder input is mandated. In addition, we

Organization	Yes or No	Question 2 Comment
Transmission Association, Inc.		do not believe NERC Reliability Standards have the authority to dictate stakeholder outreach processes. For several reasons, including the time required for public input, permitting, acquisition, and construction, most transmission projects take several years to build. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The Footnotes do not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has provided a 60-month implementation plan.		
Duke Energy	No	Since item 2 describes the public notice that must be provided, the phrasing of 2.b should be revised to replace the words "Specific applications" with the words "Summary description". "Specific applications" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b'. That level of detail could certainly be provided to meeting participants, but shouldn't be necessary for the public notice.
Response: The SDT agrees with the comment that: "Specific applications of the planned Firm Demand interruption under footnote		

Organization	Yes or No	Question 2 Comment
12" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b' and is not necessary for the public notification. The language has been changed to clarify the SDT's intent. Specific location(s) of the planned Firm Demand interruption under footnote 'b'.		
California Independent System Operator	No	The process presented in Section I of Attachment I is overly prescriptive. Identifying the need for stakeholder consultation on this issue within the consultation process already employed by the Transmission Planner or Planning Coordinator should be sufficient detail. In particular, however, we suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution? There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: The SDT has recognized that the requirement to notify all stakeholders is too broad and has replaced "all affected stakeholders" with "affected stakeholders." Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for		

Organization	Yes or No	Question 2 Comment
retail electric service issues Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: The SDT believes the stakeholder process is required and it must provide specific information of the intended purpose and scope so stakeholders can understand the reason for Firm Demand interruption is appropriate. The SDT has debated the language and believe that it is appropriate. No change made. The Stakeholder Process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
Hydro-Quebec TransEnergie	No	The Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish load loss values. Also, the use of Firm Demand interruption in the Corrective Plan should not be limited only to the Near-Term Transmission Planning Horizon. It should also be allowed for the Long-Term horizon, at least for Multiple Contingencies.
Response: The SDT has revised the Stakeholder Process to allow use of an existing regulator/RTO Stakeholder Process, as long as it meets the criterion set in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following The Stakeholder process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm		

Organization	Yes or No	Question 2 Comment
Demand interruption meets the conditions shown in Attachment 1.		
NorthWestern Energy (NWMT)	No	Comments: It is unclear how the dispute resolution process would treat stakeholders with different concerns. We suggest that Item 5 of Attachment 1 be deleted.
Response: The SDT believes that a dispute resolution process is an essential part of the Stakeholder Process. No change made.		
Georgia Transmission Corporation	No	Item #1 in Section I should be reworded: From This....”Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” Reworded to say: “Meetings must be open to all affected NERC Registered Entities including applicable regulatory authorities or governing bodies responsible for retail electric service issues.”The concern is that stakeholders could be too broadly construed including residential, commercial, industrial customers, and even more so (i.e transitory customers). We recommend that the sentence be reworded as shown above. Additionally, GTC request feedback from the SDT's intent. Is a stakeholder meeting required every year a planning assessment is done showing that non-consequential load loss is required?
Response: The SDT believes that the current language is clear and that the suggested change does not add further clarity. No change made. The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		

Organization	Yes or No	Question 2 Comment
ISO New England Inc.	No	With regard to Section I, in paragraph I.5, the stakeholder process includes a dispute resolution process. Existing ISO/RTO stakeholder processes are FERC approved and rigorous, requiring a dispute resolution process goes beyond the existing requirements in ISO/RTO tariffs. Item I.5 should be eliminated.
Response: The SDT has revised the stakeholder process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion set in Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following The SDT concluded that a dispute resolution process is an essential part of the process and no change was made to the process.		
South Carolina Electric and Gas	No	See response to question #1
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to Question 1.
Southwest Power Pool Reliability Standards Development Team	Yes	See comment From question 1
Response: Please see response to Q1.		
Lincoln Electric System	Yes	Although LES agrees in general with the description and components included as part of Section I, we suggest the following wording changes to enhance Section I. Recommend the drafting team delete item 2(c) as it is duplicative of item 4 which is more succinctly worded. Also, recommend additional wording be added to the end of item 3 to provide meeting participants with advanced notice of the information. As an example, "information...must be made available to meeting participants [ten days prior to the meeting]."

Organization	Yes or No	Question 2 Comment
Response: The SDT believes that the current language is clear and that the suggested change does not add further clarity. No change made.		
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
Arizona Public Service Company	Yes	
Orlando Utilities Commission	Yes	
CPS Energy	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

3. **Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Based on industry comment, item 8 of Section II has been modified to clarify that adjacent Transmission Planners and Planning Coordinators are the relevant parties for assessment of potential overlapping use of Firm Demand interruption.

Based on industry comment, item 2.b of Section II has been modified to clarify the SDT's intent. However, the SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard.

Several commenters had concern about being required to provide the information in Section II, items 1, 2, 3 and 4. The SDT believes that this information is necessary for understanding the reliability impact and for stakeholders to make an informed decision.

The following changes were made due to industry comments:

Attachment 1, Section II, Bullet 2b: Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Attachment 1, Section II, Bullet 8: Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Reliability Standards Development Team	No	We need clarification on the term planner in item 8 of section 2. Since the term isn't capitalized we would like to know if this was intended to mean Transmission Planner or a adjacent Planning Coordinator for identifying a seams issue. We would like see item 2b of section 2 removed this item isn't relevant to the standard and goes beyond the purpose of this standard. We understand that this is included for curtailment of load during emergency conditions (EOP001 Attach 1) but feel it is unnecessary in planning.
Response: The SDT agrees and item 8 of Section II has been modified accordingly. 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators The SDT believes assessment of the impact of Firm Demand interruption to the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Salt River Project BrightSource Energy, Inc.	No	We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the

Organization	Yes or No	Question 3 Comment
Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative Tri-State Generation & Transmission Association, Inc. California Independent System Operator nevada power company dba nvenergy PG&E Company Modesto Irrigation Districtt Utility System Efficiencies, Inc.		community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
Response: The SDT believes that the provision of customers affected and the duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is not solely administrative and is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been changed to clarify the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
MRO NSRF American Transmission Company	No	Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote 'b'. Stakeholders that participate in stakeholder meeting can ask for any information that they want regarding the

Organization	Yes or No	Question 3 Comment
		proposed use of Firm Demand interruption. They do not need a third party to prescribe what information they need or want. So, the NSRF suggests that Section II be removed. If Section II is not removed, then the NSRF suggests that at least Items 2b, 6, and 8 be removed from the listing. o Item 2b - The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is basically broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard. o Item 6 - The verification of that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements. o Item 8 - Potential overlapping uses of footnot 'b' with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, then any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.

Response: Order 890 is not applicable to all NERC regions and is not a standard. No change made.

The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent.

2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Organization	Yes or No	Question 3 Comment
The SDT believes the wording regarding the TPL standards is necessary to ensure the focus on meeting the TPL standard's reliability requirements is not lost and that the end state following interruption of Firm Demand meets those requirements. No change made. The SDT believes application of a wide area view to the use of Firm Demand interruption is necessary to avoid reliability issues that would not be seen by an individual Transmission Planner or Planning Coordinator. There is no standard requirement for adjacent Transmission Planner/Planning Coordinator's to participate in Order 890 type processes therefore it must be addressed. No change made.		
SERC EC Planning Standards Subcommittee	No	We recommend using a technical basis for load shedding instead of a Stakeholder Process.
Southern Company	No	Southern recommends using a technical basis for load shedding instead of a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
ACES Power Member Standards Collaborators	No	(1) We disagree with with including the Facilities that will exceed their rating and the applicable contingenices. We think this information should be treated as confidential. It could be used by bad actors to create outages within communities. The risk to the Bulk Electric System is higher than the benefit of sharing this information. (2) We disagree that the Transmission Planner should be required to provide an assessment on the health, safety and welfare of the community. First, the

Organization	Yes or No	Question 3 Comment
		stakeholders will have an opportunity to provide this information through either the Transmission Planner’s stakeholder comment process or through the local regulatory agency’s stakeholder comment process. Second, these planned interruptions in firm demand are expected to be short in nature so the impacts should be minimal. Third, an assessment on the health, safety and welfare of the community is an unnecessary burden on the utility and is better suited for local governments. Even if the utility should perform such an assessment, health, safety and welfare are ambiguous terms without clear parameters or expectations for the data. Does this mean that the Transmission Planner verifies police stations, fire departments, hospitals and other critical public support agencies are not included in the planned load shed? Most electric providers already do this when developing load shed plans and are likely not going to includes such customers in any load shed plan. Fourth, communities already have plans in place for the interruption of electricity so as long a critical customers are not shed, then the impacts are likely economic in nature. (3) Bullet 3 needs to be clarified that it is not an estimated frequency but rather a historical frequency. How do you estimate a frequency for a new planned load shed? It also needs to be clarified if the historical frequency is all instances within the Transmision Planner’s area or just the specific location of the planned load shed. If it is all instances, it further needs to be clarified that it is only within its own TP area. (4) We do not believe that expected duration of the planned load shed should be required. Any duration will likely be a guess. When actual contingencies occur, the time of restoration varies. Consider the recent event in Arizona and Southern California. The report indicated that the TOP thought they could return the 500 kV line that initiated the event in a few minutes. They were unaware that the phase angle was too large to close. The expected duration is too speculative and should not be required. (5) We disagree with the need to include future plans to mitigate the planned load shed in all cases. For remote areas of the system, there simply may not be sufficient load growth to justify any other mitigation.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>(6) Item 8 should be clarified that it applies only to the Planning Coordinator. The Planning Coordinator should coordinate all of its Transmission Planner's Planning Assessments. This would include evaluating planned load shedding.</td></tr>
<tr><td colspan="3">Response: 1) The use of Firm Demand interruption and events involved should only affect local area issues and should not create issues for the BES that could be exploited by "bad actors." No change made.

2) The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. As stated, it is something that TP/PC's normally do.

2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

3) Any estimate of future performance has to be based on some sort of available historical information, even for a new line/delivery. The SDT believes it is clear that for stakeholders to make an educated decision regarding Firm Demand interruption, the information must be provided for each instance of Firm Demand interruption use within the Transmission Planner/Planning Coordinator's area. No change made.

4) The SDT believes stakeholders need an expectation of the duration in order to evaluate the impact. No change made.

5) Possible future plans could include a decision not to mitigate the need for Firm Demand interruption. No change made.

6) The standard does not dictate who performs the assessment, only that one be performed. No change made.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>BPA does not support including information under Sections II.2.a and II.2.b, estimated number and type of customers affected, or an assessment of the use of Firm Demand interruption on the health, safety, and welfare of the community as this information does not support reliability of the BES. If footnote b were applied, reliability of the BES is actually assessed by meeting the applicable TPL Standard for a single contingency with loss of load regardless of the type of customers or use of Firm Demand.</td></tr>
<tr><td colspan="3">Response: The information is necessary to make an informed judgment and assessment, with stakeholder input, as to whether</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
reliability of the BES will be maintained. Evaluation of the consequences of an event is a part of assessing reliability. No change made. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
TVA Transmission Reliability Engineering & Controls	No	Under Item #2 - TVA is not sure how to properly address "health, safety, and welfare of the community" from an regulatory standpoint. Please clarify what this would require - such as number of hospitals without emergency backup, etc? Also please see answer to question #1 - TVA beleives that only larger load drops should require a Stakeholder review.
Response: The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community See response to Q1.		
MISO	No	Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the Regional Entities (given the RE will eventually need to review and assess the reliability impact of such utilization). We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RE's review process.

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	No	Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the applicable reliability authority to review and assess the reliability impact of such utilization. We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RA's review process. Also note that use of a "stakeholder process", as per FERC's concerns, must be crisp and clear.
Response: The SDT believes the information required provides what is necessary for a high-level assessment of the impact of utilizing Firm Demand interruption and is necessary for stakeholders to make an informed decision. No change made.		
Public Utility District No. 1 of Snohomish County	No	
San Diego Gas & Electric	No	We don't support the addition of stakeholder process language.
Response: Without specific comments, the SDT is unable to respond.		
Tacoma Power	No	Item II.2.b Since this is a stakeholder process, each stakeholder can make an assessment for themselves about the effect of Firm Demand interruption on the health, safety and welfare of the community. This requirement is too vague to be enforceable. Item II.5 Particularly in the case of P2.1 contingencies, utilities may not have any plans to eliminate load shedding "at the fringes of various systems" as the FERC NOPR noted would be acceptable.
Response: Stakeholders would not be likely to have all the information required to make an informed decision. The SDT is seeking the appropriate balance between being too vague and too prescriptive. Based on comments received, the wording has been clarified to better show the SDT's intent.		

Organization	Yes or No	Question 3 Comment
2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community There is a requirement to include any mitigation plans, not a requirement to mitigate – doing nothing could be a possible plan. No change made.		
Manitoba Hydro	No	1 a. It would be very difficult to estimate the annual hours of exposure at or above a certain load level. 2 b. An assessment on the health, safety, and welfare of the community should not be part of a reliability assessment - this is purely subjective. 3 & 4. In situations where load interruption is a new proposal, historical data will not be available. What does the SDT expect here? 5. Is there a requirement to mitigate? If there is a requirement to mitigate, the required time frame is not identified.
Response: 1) Planning studies should provide the information necessary as to the Load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. No change made. 2) The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community 3 & 4) Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated lines/deliveries allows for estimation of future performance. 5) There is a requirement to include any mitigation plans, not a requirement to mitigate – doing nothing could be a possible plan.		
Ameren	No	We request that Items 5 and 7 also include information regarding estimated costs and schedule for implementation. Any permitting issues associated with the

Organization	Yes or No	Question 3 Comment
		alternatives should also be included. Any previous attempts to build facilities but were blocked should also be part of the record.
Response: Items 5 and 7 do not prohibit inclusion of cost, schedule information, or other project information and it is anticipated these issues would normally be included. The SDT is seeking the appropriate balance between being too vague and too prescriptive. No change made.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
City of Austin dba Austin Energy	No	Some of the information for inclusion in the Stakeholder Process is too burdensome and of limited value. In particular, 2b and 4 can be deleted because the requested information may not be available -- particularly if it is new load growth.
Response: The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated lines/deliveries allows for estimation of future performance. No change made.		
LCRA Transmission Services Corporation	No	Requirement 1 only requires that the Transmission Planner provide system load data, however, assumptions about system dispatch are also relevant. Requiring load without dispatch will not provide a complete understanding of the conditions under which Footnote 12 will apply. As a reliability standard, the Transmission Planner is required to find a range of plausible system conditions under which a criteria

Organization	Yes or No	Question 3 Comment
		violation may be resolved. The requirement (1a) to provide an estimate of the exposure creates an overly burdensome requirement to investigate a wider range of possible operating conditions than is currently performed. Requirement 2a and 2b are overly burdensome on at Transmission Planner/Transmission Owner who does not directly serve retail loads by placing a requirement on the Transmission Planner/Transmission Owner to provide data that is outside of its control to develop or maintain.
Response: The SDT believes the information in Section II is sufficient and would bring out any concerns related to dispatch conditions. No change made. Planning studies should provide the information necessary for 1.a as to the load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. The SDT believes 2.a and 2.b's provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording for 2.b has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Duke Energy	No	In Item #8, replace the word "planners" with the words "Transmission Planners".
Response: The SDT agrees, and item 8 of Section II has been modified accordingly. 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators		
Hydro-Quebec TransEnergie	No	For example, under 2 b., assessment of the impacts of interruptions on health, safety, or welfare of the community is not information that could be reasonably expected to be available to system planners. All loads may face interruptions from time to time,

Organization	Yes or No	Question 3 Comment
		and the impact on health, safety or welfare is very difficult to identify. This item should be deleted.
Georgia Transmission Corporation	No	GTC does not understand how item #2b of Section II pertains to the Transmission Planner or the Planning Coordinator. These types of assessments are beyond the scope of the Transmission Planner or the Planning Coordinator and if necessary, should possibly be done by the Load Serving Entity.GTC Recommends the SDT remove item #2b, the following sentence:"An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community."
Response: Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
NorthWestern Energy (NWMT)	No	Comments: The estimated number and type of customers affected is not needed for reliability of the Bulk Power System. We suggest removing Item 2a in Section II of Attachment 1. An assessment of the health, safety, and welfare of the community should not be required. It is too vague and coud present legal problems. We suggest removing Item 2b in Section II of Attachment 1.
Response: The SDT believes provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for		

Organization	Yes or No	Question 3 Comment
understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
ISO New England Inc.	No	Section II, Paragraph 2b requires "an assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community". A great deal of subjectivity and information that is not readily available to the Transmission Planner or Planning Coordinator would be required to accurately access the effect of load shedding on the community as required by 2b. Additionally Paragraphs II.3 and 4 require estimates of the frequency and duration of Firm Demand interruption would be difficult to provide. These requirements should be deleted. These requirements also undermine the deterministic nature of the Planning Standard. Paragraph II.2.5 that requires future plans to mitigate the need for Firm Demand Interruption should be modified to again emphasize the near term nature of single contingency non-consequential load shedding as a Planning option.
Response: Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community Planning studies should provide the information necessary as to the Load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated		

Organization	Yes or No	Question 3 Comment
lines/deliveries allows for estimation of future performance. No change made. A purpose of the stakeholder process is to ensure those impacted by use of Firm Demand interruption and the regulators responsible for quality of service have input on its use and the acceptability of the mitigation plan. No additional elaboration on the use of Firm Demand interruption in the standard is necessary. No change made.		
South Carolina Electric and Gas	No	See response to question #1
Response: Please see response to Q1.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to question 1 - the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). ERCOT also provides the following comments on Section II - the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements. II. Information for Inclusion in Item #3 of the Stakeholder ProcessThe responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: - (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:a. System Load level and estimated annual hours of exposure at or above that Load levelb. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency(ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with:a. The estimated number and

Organization	Yes or No	Question 3 Comment
		type of customers affectedb. An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community(ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance(ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance(ERCOT COMMENT: See ERCOT response to “3” above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’(ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process. Furthermore, if load shedding is allowed, this requirement doesn’t make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’(ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of whichis to identify and resolve performance issues.)

Organization	Yes or No	Question 3 Comment
		7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’(ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.) 8. Assessment of potential overlapping uses of footnote ‘b’ with adjacent planners(ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)

Response: Please see response to Q1.

1. The SDT believes the information in Section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. No change made.

2. The SDT believes the information in section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. The SDT believes provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording for 2.b has been clarified to better show the SDT’s intent.

> 2b. Assessment of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community

3. and 4. The SDT believes the information in Section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. Any estimate of future performance has to be based on some sort of available historical information even for a new line/delivery. The SDT believes it is clear that for stakeholders to make an educated decision regarding Firm Demand interruption, the information must be provided for each instance of Firm Demand interruption use within the Transmission Planner/Planning Coordinator’s area. No change made.

5. The mitigation plan identifies how reliability violations will be avoided in the future where projects or other actions are not available in time or are not cost effective. No change made.

Organization	Yes or No	Question 3 Comment
6. The SDT believes the wording regarding the TPL standards is necessary to ensure the focus on meeting the TPL standard's reliability requirements is not lost and that the end state following interruption of Firm Demand meets those requirements. No change made. 7. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. 8. The SDT believes application of a wide area view to the use of Firm Demand interruption is necessary to avoid reliability issues that would not be seen by an individual Transmission Planner/Planning Coordinator. The SDT believes assessment for Adverse Reliability Impacts is an appropriate step. However, the SDT has moved this responsibility to the ERO and deleted the Regional Entity from any involvement. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Orlando Utilities Commission	Yes	Data element 5 should probably read. "List any Future Plans or future system changes to mitigate the need for Firm Demand Interruption under footnote 'b'". There can be cases where there is no planned future project to relive the problem, or it could be expected that load will go down or changes on neighboring systems will relieve the problem.
Response: Possible future plans could include a decision not to mitigate the need for Firm Demand interruption. No change made.		

Organization	Yes or No	Question 3 Comment
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
Arizona Public Service Company	Yes	
CPS Energy	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
Lincoln Electric System	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

4. **Do you agree with the Instances for which Approval of Interruptions is required in Section III of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The 25 MW threshold for requiring regulatory authority review was questioned by several entities. The original 25 MW threshold came from the Registry Criteria for Load-Serving Entities. The data request showed that the average value of footnote 'b' utilization was approximately 19 MW. Therefore, the SDT has decided to leave the process threshold at 25 MW.

Several entities questioned having the 300 kV threshold for Contingencies because it has no material impact to Load and that the threshold should be based on a MW amount only. The SDT believes that the 300 kV threshold is appropriate, as the proposed TPL-001-2, which was accepted by industry and the NERC Board of Trustees, made a distinction between HV and EHV and the handling of Contingencies based on the 300 kV level. The SDT believes that the establishment of this threshold within footnote 'b' is consistent with that approach and places the proper emphasis on EHV.

Several entities had concerns that actions from a regulatory body won't happen quickly enough and that such a requirement was not appropriate for a reliability standard. There were also concerns voiced about inconsistencies in such an approach. The SDT understands these concerns and has clarified the language to assist in alleviating such concerns. The SDT also advises any entity wishing to utilize footnote 'b' in its planning process to start that process at an appropriate time so that it can be completed by the needed date.

Some concerns were raised about the role of the Regional Entity in this process. After reviewing the submitted comments, the SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.

The following changes were made due to industry comments:

Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 4 Comment
Southwest Power Pool Reliability Standards Development Team	No	Need clarification around why the 25MWs threshold on generation was thrown into load interruption topic. Looking at the registry criteria for generation the threshold should be 20Mws for a single unit and 75 MWs for aggregated units. Not sure where the 25MWs threshold came from for generation. The 25 MW threshold in Section III is duplicative of the registration limit for generation in the ERO Statement of Compliance Registry Criteria. It is submitted for comment at this time but will not be finalized until after the above mentioned data request is complete and the final value will be submitted for industry comment and approval in the next posting. The GOP registration criteria is 20MWs. Whereas the registration criteria for LSEs and DPs is 25MWs. There appears to be some co mingling of criteria. Additionally this raises the question of whether x =25MWs. Please clarify which you intended to use. We are concerned that getting retail service regulatory authority approval in a quick manner could be difficult. We are also concerned that if it does get caught in the process of being approved and there is no time to construct, that we would not want to be found out of compliance due to something that is out of our control.

Response: The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.

The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote “b” should start the review process at an appropriate time so that it will be completed by the required date.

> Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either:

Organization	Yes or No	Question 4 Comment
Salt River Project	No	While we do agree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to give approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
MRO NSRF	No	The NSRF suggests that Section III be removed for the following reasons. o The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote 'b' are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stiputlations regarding disapproval of the use of footnote 'b' proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote 'b' approval sipulations. o The diversity of applicable regulatory authorities and governing bodies, as well as their justicitional scope or criteria with respect to the approval of interrupt retail electic service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed Approval stipulations in the

Organization	Yes or No	Question 4 Comment
		TPL-002 standard. If Section III is not removed, then the NSRF suggests the following changes. o Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. o Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. o Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radial fed loads that are much geater that 25 MW and there are no stackholder meetings and required approvals for allowing the loads to be fedd radially (subject to interruption for Category B contingencies) rather than being network fed. The DOE threshold for requiring formal system event analysis is 100 MW of load dropping. So, why should the TPL-002 standard required special approvals to allow less than 100 MW of load be subject to interruption to assure BES reliability? o Change the text of “in Year One of the Planning Assessment” to “in the ten year planning horizon of the Plannign Assessment”. The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unforecast load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). o The NSRF is concerned that the current wording, “Corrective Action in Year One of the Planning Assessment” could be interpreted to require an annual stakeholder process review and approval. The NSRF suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffiming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission

Organization	Yes or No	Question 4 Comment
		construction if needed. The specific defined period of review should allow entities to operate in an effective manner. The NSRF is also concerned about the condition where approval was granted and then removed. Would an entity be instantly non-compliant to the TPL standards? If this is a possibility, the Standard Drafting Team should add a grace period that allows an entity to credibly construct a project to remain compliant.
American Transmission Company	No	ATC recommends that Section III be removed for the following reasons. o The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote ‘b’ are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stipulations regarding disapproval of the use of footnote ‘b’ proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote ‘b’ approval stipulations. o The diversity of applicable regulatory authorities and governing bodies, as well as their jurisdictional scope or criteria with respect to the approval of interrupt retail electric service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed approval stipulations in the TPL-002 standard. If Section III is not removed, then ATC recommends the following changes. o Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. o Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements

Organization	Yes or No	Question 4 Comment
		are not material to impact on the affected load. o Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radially fed loads that are much greater than 25 MW and there are no stakeholder meetings or required approvals for allowing the loads to be fed radially. The DOE threshold for requiring formal system event analysis is 100 MW. So, ATC believes the TPL-002 standard should not require special approvals to allow less than 100 MW of load to be interrupted to assure BES reliability. o Change the text of "in Year One of the Planning Assessment" to "in the ten year planning horizon of the Planning Assessment". The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unexpected load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). o ATC is concerned that the current wording, "Corrective Action in Year One of the Planning Assessment" could be interpreted to require an annual stakeholder process review and approval. ATC suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffirming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner.

Response: If you have already gotten approval from regulatory bodies in your planning process, then Section III is basically already accomplished, and carrying out the remaining details should not be burdensome. No change made.

While it may be true that regulatory authorities and governing bodies are diverse and complex, they are representing their area of responsibility. What may be acceptable in one area, may not be acceptable in another. This is determined by the appropriate authorities. No change made.

The SDT does not believe approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite or essential. The focus of this portion of the standard is dropping Load and when approval is necessary.

Organization	Yes or No	Question 4 Comment
There is no benefit in including approval of Corrective Actions. No change made. The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load dropping, it should require approval. No change made. The data request also showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made The text regarding Year One of the Planning Assessment just means that approval from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that approval cannot be sought sooner. The intent of the SDT was that a review must be obtained one time from the appropriate regulatory body. It does not need to be reviewed again unless the situation changes. The SDT has changed the wording to the following: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either: The proposed TPL-001-2 accommodates this concern regarding circumstances beyond the control of the Transmission Planner or Planning Coordinator in Part 2.7.3 of Requirement R2.		
SERC EC Planning Standards Subcommittee	No	We recommend using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds are correct. The Stakeholder Process should not even be initiated for less than these threshold levels.
Southern Company	No	Southern recommends using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds given in the draft seem appropriate. Furthermore, we believe the Stakeholder Process should not even be initiated for less than these threshold levels.

Organization	Yes or No	Question 4 Comment
		Lower amounts of load and lower voltage contingencies do not need to be taken through a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
ACES Power Member Standards Collaborators	No	(1) What is the justification for selecting a 300 kV contingency as a threshold for requiring local regulatory agency approval? What if the planned load shed is only for 1 MW? If a threshold is required, we think it should be based on load size rather than contingency size? (2) What is the justification for selecting 25 MW of planned firm load interruption as a threshold for requiring local regulatory approval? The threshold could be set based off of the accompanying Section 1600 data request. Since there are likely not many instances, it could be required for any new instance that exceeds the existing planned load shed amounts. Thus, the threshold would be set just above existing planned load interruptions. (3) A disclaimer should be added to clarify that an entity may still have to seek local regulatory agency approval per the local regulatory agency's rules. Nothing in the NERC standard will change the local regulatory agency's rules. (4) What if the local regulatory agency does not want to address the planned load

Organization	Yes or No	Question 4 Comment
		shed in the planning time frame? What is the Transmision Planner required to do? While it is likely a local regulatory agency would be interested in addressing a planned load interruption, nothing in the NERC or Commission rules can compel a local regulatory agency to address such matters in a specific time frame. (5) Bullet 1.a is confusing. Is it intended to say that if two Elements are part of a contingency and the Elements have different voltage classes, the Element with the lowest voltage class must exceed the 300 kV threshold? If this is the case, the bullet needs further clarification because it does not state this clearly. (6) The first paragraph after section III appears to contradict bullets 1 and 2. Bullets 1 and 2 place contingency and load thresholds on the planned firm load interruption. However, this paragraph says that the regulatoy body responsible for retail electric service must approve the planned load shed before it can be used in Year One of the planning assessment. If the purpose is for the thresholds to apply beyond Year One and any instance in Year One to require approval, then the language regarding the thresholds needs to clarify that the thresholds apply beyond Year One only. (7) We think it is redundant for the Regional Entity to evaluate planned interruptions of firm load in its footprint. The Planning Coordinator has a wide area view and is already required to do this for its footprint. The Planning Coordinator already works with its neighbors to evaluate impacts. Requiring this evaluation by the Regional Entities is arbitrarily based on historical and political boundaries. Many Planning Coordinators have views that are broader than the Regional Entity view because they are in multiple regions. If this evaluation will be required on a regional basis, why won’t it be required on an interconnection? (8) The evaluation required by the Regional Entity may be completed before planned load interruption is approved by local regulatory body. The TP and PC must submit the data based on their plan before the local regulatory body approves the planned load interruption. The Regional Entity must complete its evaluation within 45 days of receiving the information. There is no obligation for the local regulatory body to act within 45 days. Wouldn’t it make more sense to evaluate the planned load shed after

Organization	Yes or No	Question 4 Comment
		it is approved by the local regulatory body?

Response: (1) The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that Transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load shed, it should require approval even if it is only 1 MW.

(2) The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.

(3) There is no need for such a disclaimer in a NERC Standard. An entity has to abide by other applicable rules outside of the standard. No change made.

(4) The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. If the local regulatory agency does not want to address the planned Load shed, then they are giving their tacit approval to the Load shedding.

> Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

(5) Yes. For 1.a to apply, the Element with the lowest system voltage level must be 300 kV or above. The SDT believes the wording is clear. No change made.

(6) The text regarding Year One of the Planning Assessment just means that approval from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that approval cannot be sought sooner.

(7) The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.

> Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of

Organization	Yes or No	Question 4 Comment
whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. (8) No. The planned Load shed should not be reviewed by the local regulatory body unless it has been determined that there are no Adverse Reliability Impacts.		
Bonneville Power Administration	No	Regarding Section III.2 as stated above, BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases.
Response: The SDT does not agree that setting a quantitative limit would push Transmission Planners to plan the system to meet such a limit for a single Contingency in all cases. The footnote states that an objective of the planning process should be to minimize the likelihood and magnitude of Load shed. However, a quantitative limit is needed to ensure that unreasonable amounts of Load shed are not proposed. No change made.		
TVA Transmission Reliability Engineering & Controls	No	Please see answer to question #1. TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA beleives that only larger load drops should require a Stakeholder review.
Response: Please see response to Q1.		
Arizona Public Service Company	No	AZPS does not agree that approval by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity approval. There would be no adverse affect of non-consequential load tripping on the BES. No reason for Reginal Entity involvement.
Response: The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.		

Organization	Yes or No	Question 4 Comment
Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative California Independent System Operator nevada power company dba nvenergy PG&E Company Modesto Irrigation Districtt Utility System Efficiencies, Inc.	No	While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		

Organization	Yes or No	Question 4 Comment
The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
MISO	No	We generally agree with the instances for which approval or interruptions is required, but do not agree with the requirement to seek regulatory approval.In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the RE for review and concurrence. Along with the submission, the RE may require the proponent to include a copy of appropriate regulatory approval (which the entity should have already obtained). The conditions (1) and (2) for seeking regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the RE. Additionally, Attachment 1 requires that the ERO develop a methodology on evaluation criteria to be published for determining Adverse Reliability Impacts for approval by the ERO. Planning Assessments are performed on an annual basis. The Attachment 1 process and ERO methodology may require a lengthy approval process that must be repeated on an annual basis.
Response: The SDT has modified the footnote to require regulatory authority review rather than approval. This should help alleviate some of the concerns. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority		

Organization	Yes or No	Question 4 Comment
or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either: The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		
Essential Power, LLC	No	This solution requires filing with a regulatory body for any extra interruptions. This seems to be a lot of effort and language for a contingency event that the system is supposed to be able to handle.
Response: The SDT believes that the stakeholder process is necessary to ensure that Load shed is utilized for single Contingencies only under limited circumstances. No change made.		
Tacoma Power	No	As noted in our response to question 2, regulatory approval is often a slow process and is not conducive to repeating annually. Instead of a 25 MW limit, a 300 MW limit that corresponds to the reporting level of firm demand in EOP-004 is more appropriate.
Response: The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		

Organization	Yes or No	Question 4 Comment
The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Manitoba Hydro	No	The Section III states that regulatory authority approval is required for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV. However, a regulatory authority cannot approve interruption of Firm Demand unless it already has such jurisdiction that is conferred upon them by legislation. A reliability standard cannot confer that jurisdiction. Further, the regulator is already part of the proposed stakeholder group and will have input into the proposal. The Section III requires the Regional Entity to review the proposed use of Firm Demand interruption under footnote 'b'. What impact does it have on the Regional Entity to necessitate a review, if the stakeholders have already agreed to a process, TPL Reliability Standards performance requirements have been verified as in Section II.6, and potential overlapping uses have been assessed with adjacent planners as in Section II.8. What criteria will the Regional Entity use to make their assessment of Adverse Reliability Impacts and potential cumulative effects given the above TPL performance must be met? This requirement can lead to inconsistent decisions between regions.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	No	We generally agree with the instances for which approvals or interruptions are required. Approval is to be granted by the Reliability Coordinator or applicable reliability authority. (1) In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the Reliability Coordinator for review and concurrence. The conditions (1) and (2) for seeking explicit regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the applicable reliability authority. (2) We suggest deleting Item 1 in the first paragraph (with its a and b bullets) and just indicating that planned Firm Demand interruption requires approval if it is greater than 25 MW (or other threshold). Requirements for approval of the use of Firm Demand interruption should be independent of the voltage level of the contingency. (3) We propose deleting the sentence in the second paragraph “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ‘x’ MW”. A fixed limit on the allowable size of Firm Demand interruption can not be technically justified for the whole continent and each case should be assessed to determine if its impact on reliability of the bulk transmission system is acceptable or not. The impact of each case on the affected customers (economic, welfare, etc.) will also be reviewed and approved by the regulatory authority or governmental body of each jurisdiction and a “reliability” standard must not impose limits and restrictions pertaining to these aspects. (4) The third paragraph proposes that the Regional Entity should review each case of Firm Demand interruption and verify that there are no Adverse Reliability Impacts.

Organization	Yes or No	Question 4 Comment
		We propose instead that the transmission planner or planning coordinator study the BES performance requirements and the reliability impacts of Firm Demand interruption, including its correct operation, miss-operation, and the failure to operate. The transmission planner should then submit a report of this assessment to the Reliability Coordinator for review and approval.
Response: (1) Regulatory review is not always sought in advance. The SDT believes this review is necessary when the planned Load shed exceeds either of the thresholds in Section III. No change made. 2) The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load shed, it should require approval even if it is only 1 MW. No change made. (3) The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW. (4) The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.		
Ameren	No	We do not believe that section III is needed, and particularly if an approval is included as part of the section I process. We do not subscribe to dropping Firm Demand (non-consequential load) for single contingency events, and do not see a need to include a voltage threshold as part of the contingency requirements. All single contingencies in Category B should be

Organization	Yes or No	Question 4 Comment
		applicable.
Response: Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. Having the ERO review the application of footnote 12 will provide needed continent-wide consistency. The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for load dropping, it should require approval even if it is only 1 MW. No change made.		
ReliabilityFirst	No	ReliabilityFirst has a major issue/concern with Attachment 1, Section 3 (specifically the last paragraph regarding approval). This section requires the Regional Entity to review each proposed use of Firm Demand interruption under footnote 12 in order to verify that there are no Adverse Reliability Impacts. The paragraph goes on to require the Regional Entity to make its determinations and evaluation of Adverse Reliability Impacts using a published methodology approved by the ERO. First, since the Regional Entity is not a user, owner or operator of the BES, ReliabilityFirst believes the Regional Entity should not have requirements placed upon them. Furthermore there is no guidance on what is required to be placed within the published methodology. ReliabilityFirst believes this verification is outside the Regional Entity scope as delegated by the ERO. ReliabilityFirst believes that if such verification by the Regional Entity is required, it should be specifically laid out in the NERC Rules of Procedure and not an attachment within a standard.
American Electric Power	No	AEP is concerned that not all Regional Entities are the same in regards to their engineering and planning staff, and is not confident that they would all have the resources necessary to perform the required analysis. AEP is concerned by any attempt to require that a Regional Enity adhere to processes and prodecures that have not yet been established. FERC has made comments in the past regarding requirements places upon regional entities (RRO), and while this standard does not

Organization	Yes or No	Question 4 Comment
		yet apply, is does indirectly obligate them to rules and procedures not yet established.
Response: The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
City of Austin dba Austin Energy	No	The 25 MW threshold for Approval of Interruptions of Firm Demand under Footnote 'b' is too low. It should be increased to 50 MW because there is an elaborate Stakeholder process to work through the reliability concerns.
Response: The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
Lincoln Electric System	No	For item 1(b) in Section III, LES requests that the drafting team clarify why approval by the regulatory authority for a generator contingency is based on the high-side voltage of the GSU rather than the generator capacity. LES believes the generator capacity, rather than the high-side voltage of the GSU, provides a more consistent basis for determining necessity for approval from the applicable regulatory authority or governing body. Additionally, LES asks for further clarification as to whether the steps referenced for

Organization	Yes or No	Question 4 Comment
		Year One of the Planning Assessment extend to Year Two and beyond.
Response: The SDT disagrees that generator capacity is a better basis for determining the necessity for review. The requirements within the TPL standards have different performance levels based on a 300 kV voltage threshold for the Contingency. This distinguishes Facilities generally constructed to transmit power from Facilities used to distribute power to Load centers. The SDT believes this to be a better basis for determining what is important enough to require review from regulatory authorities. No change made. The text regarding Year One of the Planning Assessment just means that review from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that review cannot be sought sooner.		
LCRA Transmission Services Corporation	No	See previous comments about use of the term “Firm Demand”.
Response: Please see previous response.		
Tri-State Generation & Transmission Association, Inc.	No	We disagree with the instances for which Approval of Interruptions is required as proposed by Section III of Attachment I. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The reason being that the time required to construct a project to mitigate the issues can take several years. This is due to the need for public input, permitting, acquisition, and construction. Attachment I does not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests. Attachment I also states that “Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment...” The need for approval seems burdensome such that it does not allow for temporary mitigation to meet BES performance criterion while other avenues are explored and vetted. The intent of Section III is genuine, but we feel that it is over-reaching for a NERC

Organization	Yes or No	Question 4 Comment
		Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
Response: The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either: Section III is not requiring action from the regulatory authority. It requires action from the Transmission Planner or Planning Coordinator. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
Duke Energy	No	Section III is confusing. Are the last two paragraphs of Attachment 1 supposed to be part of Section III? These paragraphs, when read in combination with the first paragraph of Attachment 1, seem to say that any time a Firm Demand interruption using footnote 'b' or footnote 12 shows up in the Near-Term Transmission Planning Horizon, the Stakeholder Process must be invoked. It would seem more reasonable to invoke the Stakeholder Process only when such interruption occurs in Year One of

Organization	Yes or No	Question 4 Comment
		the Planning Assessment.
Response: The last two paragraphs are intended to be included in Section III. The SDT believes it is more appropriate to require the stakeholder process whenever load interruption is planned in the Near-Term Transmission Planning Horizon. That allows more time for all interested parties to be informed.		
Hydro-Quebec TransEnergie	No	For example, in 1a., it is not clear what is meant by "the stated performance criteria regarding allowances...". Why is it necessary to give this kind of explanation? In 1b., the use of the term "non-generator step up transformer" is unusual. Suggest rewording 1b to read:For a generator or generator step up transformer outage Contingency, the extra high voltage (EHV) limit applies to the BES connected voltage (high-side of the Generator Step Up transformer). For any other transformer outage Contingency, the EHV limit applies to the low-side winding (excluding tertiary windings).
Response: In the context of the complete sentence, the SDT believes that the comment is clear. No change made. The terminology is consistent with the Board of Trustees approved TPL-001-2. No change made.		
NorthWestern Energy (NWMT)	No	Comments: A NERC Standard should not require action from a regulatory authority to approve the use of Firm Demand interruption. There is too much diversity in regulatory authorities over the industry-wide area. This would increase the work load of the Regional Entities without improving reliability. We suggest removing Section III of Attachment 1.
Response: The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns.. Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under		

Organization	Yes or No	Question 4 Comment
footnote 'b' if either: Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. The SDT believes that an evaluation by the ERO of the potential for adverse system impacts is needed to provide continent-wide consistency. Therefore, Section III is needed. No change made.		
Georgia Transmission Corporation	No	GTC would appreciate if the SDT could please clarify if the approval of a regulatory authority or governing body is referring to the Regional Entity.The first sentence in Section III:"Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:..."
Response: No, that sentence refers to regulatory authorities such as a state public service commission.		
ISO New England Inc.	No	Section III describes the instances where Approval of Interruptions of Firm Demand are required under footnote 12. It is not clear whether under Paragraph III.1.a and Paragraph III.1.b the Transmission Planner is to base the determination on either contingency or both contingencies i.e. is "and" logic to be applied or is "or" logic used? Paragraph III.2 requires such approval for interruption equal to or greater than 25 MW, this is a very small amount of load to be required to bring to a stakeholder approval process for second contingency events. This amount should be increased to at least 100 MW. Additionally in Section III, it is not clear who the "regulatory authority or governing body responsible for retail electric service issues" is. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. The Attachment goes on to state "The Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO". This is essentially a "fill in the blank" requirement and makes it necessary to

Organization	Yes or No	Question 4 Comment
		comment and approve the footnote attachment without the benefit of reviewing a proposed methodology.
Response: Section 3 clarifies the criteria for the application of footnote 12. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed; as such, they are an "or" requirement and the 'or' has been added to the Attachment. The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. The regulatory or governing body should be known by the entity who plans to use footnote 12.		
South Carolina Electric and Gas	No	See response to question #1
Response: Please see response to Q1.		
Electric Reliability Council of Texas, Inc.	No	If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section III instances requiring regulatory approval. As with the other stakeholder process sections, that section should be eliminated.
Response: Industry and the NERC BOT have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The SDT is now attempting to address FERC's concern expressed in their Remand Order 762 that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process, is vague, unenforceable, and not responsive to the previous Commission directives on this matter. The draft		

Organization	Yes or No	Question 4 Comment
posted for comment adds detail and specificity to the already-approved approach. The SDT does not believe it appropriate to move away from the industry and BOT approved Stakeholder Process approach. No change made. Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. The SDT believes that an evaluation by the ERO of the potential for adverse system impacts is needed to provide continent-wide consistency. Therefore, Section III is needed. No change made.		
San Diego Gas & Electric	No	
Public Utility District No. 1 of Snohomish County	No	
Response: Without specific comments, the SDT is unable to respond.		
Orlando Utilities Commission	Yes	Comment #1: The maximum threshold should be in the Footnote, not in the Attachment. Comment #2: I think the role identified for the Regional Entity is appropriate. Comment #3: I like the concept that regulatory approval is not required until year one. However I think either the ordering of language or the formatting needs to be changed to make it clear that the year one applies to only those that need regulatory approval. Maybe change the section to read... "Section IIIFirm Demand Interruptions under footnote 'b' that meet either or both of the criteria below are required to have approval by the applicable regulatory authority or governing body responsible for retail electric service issues. The regulatory approval is required prior to the use of that remedy in Year One of a Corrective Plan in the Planning Assessment. (Existing 1 & 2)(Existing RE Review)
Response: The maximum threshold is the last sentence of the footnote, and is also cited in Section III of the Attachment. No change made.		

Organization	Yes or No	Question 4 Comment
The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:		
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
CPS Energy	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here.

Summary Consideration: Many commenters proposed changes to the applicable planning events for which footnote 12 applies in the new proposed TPL-001-2a standard. The SDT clarifies that the planning events for which footnote 12 are applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process.

Some commenters indicated confusion surrounding changes made to footnote 12 and Attachment 1 in the proposed TPL-001-2a standard in regard to the use of the term Firm Demand interruption. The SDT acknowledges that the references to Firm Demand Interruption should reference Non-Consequential Load Loss in footnote 12. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes.

Some commenters continue to weigh-in on FERC's jurisdiction in regard to continuity of service to Load. FERC Order 762, beginning at Paragraph 23, discusses FERC's position on jurisdictional issues. This topic was well-vetted in the development of TPL-001-2, and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team.

The following change was made due to industry comments:

Effective date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

Attachment 1 – Section I, last paragraph: An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 5 Comment
NorthWestern Energy (NWMT)		Comments: Footnote 12 should be added to Category P2 Single Contingency Event 2, Bus Section Fault, and to Category P2 Single Continency Event 3, Internal Breaker Fault , for EHV in the Non-Consequential Load Loss column.
Response: The planning events for which footnote 12 are applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
ACES Power Member Standards Collaborators		(1) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizion but year one does not utilize the planned load shed, they have four years to develop another solution. Why should great effort and resources be expended in year five when another solution will likely be developed? (2) This standard does not consider if the local regulatory body will act in time to approve the use of planned Firm Demand interruption. We believe the standard needs to consider that the Planning Coordinator and Transmission Planner may not be able to control the timelines of local regulatory agencies. As long as the PC and TP have done their part by submitting the data, they should be able to rely on the planned Firm Demand interruption until the local regulatory body acts. If the planned Firm Demand interruption is not approved, then the TP and PC should be given more time to address the transmission performance deficiency. (3) Several terms are used for the use of planned load shed. Non-consequential load loss and Firm Demand interruption are two examples. We suggest using one term consistently throughout the standard.

Organization	Yes or No	Question 5 Comment
Response: (1) For reasons similar to those raised by the commenter, the SDT limited Attachment 1 as being applicable only to planned use of Firm Demand interruption in the Near-term Planning Horizon (Years 1-5), recognizing that plans may change. The SDT believes it is appropriate to require the stakeholder approval process in the Near-term Planning Horizon. The Near-term Planning Horizon plans should become more stable over those identified on the Long-term Planning Horizon. No changes made. (2) The SDT has clarified the language concerning regulatory approval to show that review is what is actually required. Review by the regulatory authority or governing body responsible for retail electric service issues is only required in certain instance of planned Firm Demand interruption and if planned for use in Year One of the Near-Term Transmission Planning Horizon. When required, the indicated review must be obtained before it can be part of a Corrective Action Plan. Until such review, the planner would need to consider and list alternate Corrective Action Plans within its assessment. The SDT has also clarified that such reviews need only be done once, unless material changes have taken place. The SDT believes that these changes should alleviate the majority of lead-time concerns, although an entity should always build sufficient time for the process to play out into its planning cycle. (3) An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application. (4) Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. **(5)** The terms used are appropriate since the existing FERC-approved TPL standards and the proposed TPL-001-2 (NERC Board of Trustees approved 8/4/2011) use differing terminology for the common topic (planned load shed) of both footnote 'b' (Firm Demand Interruption) and footnote 12 (Non-Consequential Load Loss). The SDT acknowledges that the reference to Firm Demand Interruption should reference Non-Consequential Load Loss. The SDT has made appropriate revisions to proposed TPL-001-2a, Attachment I.		
Independent Electricity System Operator		(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions,

Organization	Yes or No	Question 5 Comment
		including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed/approved by the Reliability Coordinator. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the same load interruption that is allowed for the related P1 contingency. Table 1 currently does not allow any load to be interrupted for an EHV single contingency if the primary circuit breakers fail to clear the fault (Category P4, “Fault plus stuck breaker”). But if load X is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load X if the primary breaker fails and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load X. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of the foot note ‘b’ should be that interruption of load must not adversely impact the reliability of the interconnected BES because reliability of supply to load and/or supply continuity is mandated by the jurisdictional authority. (4) We submit that the scope of NERC’s mandatory standards does not extend to assessing or setting requirements for non-jurisdictional entities, unless such facilities are necessary for the operation of the interconnected BES or have an adverse impact on its reliability. For Canadian entities there are regulatory requirements and processes under the purview of the relevant regulatory authorities that we believe are adequate. Accordingly, customer interests are protected and are not subject to

Organization	Yes or No	Question 5 Comment
		unilateral decisions of the transmission planner. In all cases, steps are taken at the planning, design, and operations stages of system development such that non-consequential Firm Demand interruption would not adversely impact the BES and the affected customer has been given the opportunity to avail themselves of other options under the transmission development rules in the relevant jurisdictions. (5) The requirements of the footnote (including attachment) will amount to a mandate to construct additional transmission which is inconsistent with Section 215 (i) (2) of the US Federal Power Act which specifically does not authorize the ERO "to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. (6) We suggest that NERC should not include and/or address load reliability or load supply continuity requirements within the BES Reliability Standards. In Canada, these requirements and approvals are with relevant reliability or regulatory authority. If NERC feels obligated to include such requirements for load reliability issues in US, then we propose that non-jurisdictional entities must be exempted from these requirements similar to the provisions in NUC 001. (7) The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after each "applicable regulatory approval" in the Effective Dates Section A5 of both draft standards, to the following effect: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."

Response:

(1) The SDT thanks you for your general support of the proposed stakeholder process. It's anticipated that the Reliability Coordinator will be a stakeholder participant and could raise any concerns they believe are warranted. The SDT appropriately set the BES reliability approval to the Regional Entity with ERO backstop authority per FERC Order 762, Par. 55. Paragraph 55 states in part: "NERC and the Regional Entities provide both objectivity in the decision-making process as well as the necessary

Organization	Yes or No	Question 5 Comment
reliability-focused expertise." No change made. (2) The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project which aims to clarify the stakeholder approval process. No change made. (3) The proposed Attachment 1 achieves the view stated by the commenter. BES Reliability is assured by the Regional Entity and ERO where warranted. The approval by the regulatory authority or governing body responsible for retail electric service issues addresses continuity of service to end-use Load. No change made. (4) The proposed Attachment 1 process appropriately sets governance for both the ERO and Regional Entities to ensure no Adverse Reliability Impact of the BES. If existing processes are already in place to ensure end-use Loads are appropriately protected, those processes may be utilized to fulfill the Attachment I obligations. No changes made. (5) FERC Order 762, beginning at Paragraph 23 discusses the FERC's position on jurisdictional issues that are raised by the commenter. This topic was well-vetted in the development of TPL-001-2 and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team. No changes made. (6) There are no current exemptions in the TPL standards, and it is not within the scope of the SDT to introduce any at this time. No change made. (7) The SDT has revised the effective date language to reflect the latest guidance received from the Standards Committee. The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.		
MISO		(1) The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of

Organization	Yes or No	Question 5 Comment
		stipulating it in the standard. (2) It may be more appropriate to develop a Standards process that covers the technical aspects of using a footnote 12 and leave regulatory review and approval to FERC and State agencies.
Response: (1) The SDT respectfully disagrees with the commenter. Inclusion of the Attachment 1 text within the Rules of Procedure might be appropriate for consideration if the process had wide impact on multiple NERC reliability standards. As such, since limited to use within the TPL standards, its inclusion directly within the TPL standard(s) is applicable. No changes made. **(2)** The SDT believes the Attachment 1 process strikes the appropriate balance of regulatory oversight. BES Reliability is assured by the Regional Entity and ERO where warranted by assessing any Adverse Reliability Impact. The regulatory authority or governing body responsible for retail electric service issues addresses continuity of service to end-use Load. No change made.		
Deseret Generation & Transmission Cooperative Salt River Project Los Angrles Department of Water and Power Tri-State Generation & Transmission Association, Inc. nevada power company dba nvenergy PG&E Company		: The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a

Organization	Yes or No	Question 5 Comment
		bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Hydro-Quebec TransEnergie		Footnote 12 is not applied to Categories P4 and P5, which would include a EHV stuck breaker or failure of a non-redundant relay for a Multiple Contingency. The Load loss restriction for the contingencies listed in P4 and P5 is more restrictive than for the loss of a EHV double circuit line. Statistics indicate that the contingencies presented in P4 and P5 are less frequent. HQT requests that Footnote 12 should also be used for P4 and P5 contingencies for EHV. Even though considering Firm Demand interruption in planning might not be common practice, HQT agrees that the proposed Footnote 12 should maintain such a possibility.
Response: The planning events for which footnote 12 are applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Essential Power, LLC		As written, this change is complex and will be difficult to execute without additional turmoil on the planning end and offers limited clarification. Some additional issues to consider;1. Should this level of contingency allow isolation/removal of load or generation if not part of the outage? 2. Should additional generation be allowed to be removed, again considering the contingency level?
Response: 1. The binary question of applicable use was well vetted during the development of both the revised footnote ‘b’ and footnote 12. It is clear that some use, appropriately bounded, is the desire of industry and FERC. The SDT believes the proposed Attachment 1 provides the clarity sought by FERC in its remand of footnote ‘b’ and that the process is reasonable in its approach. No		

Organization	Yes or No	Question 5 Comment
changes made. 2. Generation is not addressed in footnote ‘b’. No change made.		
Public Utility District No. 1 of Snohomish County		Comments: SNPD generally disagrees with the draft process that has been developed, and notes that infrequent interruption of small amounts of non-consequential load under limited conditions that does not negatively impact a neighboring TOP is not a reliability issue. Instead it is a cost of service and customer service matter best left to the local and state regulatory bodies. The time and resources spent on this issue at the national level diverts scarse resources and attention from more important efforts that might actually benefit the reliability of the BES. SNPD supports the Pacificorp Revision of TPL-002 footnote ‘b’ and TPL-001 footnote 1 Comments- The proposed revisions will require regulatory approval for interruptions of firm demand under TPL-002 footnote b or TPL-001 footnote 12 if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than or equal to 25 MW. The 2011 peak winter and summer loads in the Western Electricity Coordinating Council (WECC) region were 131,471 and 152,211 MW respectively. Total installed generation is 229,189 MW. There are 120,385 miles of AC transmission lines 100 kV and above, and of that total, 31,138 miles of AC transmission lines are operated at voltages above 300 kV. There are 1,744 miles of DC transmission lines.The proposed revisions would add considerable process and documentation for any interruptions, and will require regulatory approval if the interruption is greater than 25 MW. This is 0.016 percent of the WECC peak load. The planning standards already require Category B1 contingencies to be considered which result in the loss of a single generator since individual generator units range in size up to more than 1000 MW. Since these contingencies are routinely studied, it is very, very difficult to imagine that the loss of 25 MW or more of firm demand under TPL-002 footnote b or TPL-001 footnote 12 is so critical to the reliability of the BES that it deserves not only a lengthy footnote, but a two page attachment detailing a

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>complex and lengthy process detailing requirements public meetings, procedures for questions, specifications for documentation, and even a dispute resolution process. As this is not a BES reliability issue, any action regarding potential curtailments of local loads should occur at the local level where the cost and benefit of improvements can be properly assessed. The recent blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power was not due to planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. SNPD is not aware of any regional disturbances or cascading events that were due to planned or controlled interruptions of electric supply where a single contingency occurred on a transmission system. As these proposed requirements could be removed from the Reliability Standards with little or no effect on reliability and would, if anything, increase the efficiency of the ERO compliance program, the proposed limitations on curtailment of firm demand under TPL-002 footnote b or TPL-001 footnote 12 should be removed.</td></tr>
<tr><td colspan="3">Response: The feedback offered is largely aimed at FERC's jurisdictional issues in regard to continuity of service of end-use Load. FERC Order 762, beginning at Paragraph 23, discusses the FERC's position on jurisdictional issues that are raised by the commenter. This topic was well-vetted in the development of TPL-001-2 and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team. No changes made.

In regard to support offered for the Pacificorp proposal, we direct the commenter to view the SDT response to Pacificorp comments.</td></tr>
<tr><td>Tacoma Power</td><td></td><td>FERC order 762 states that "to plan for the loss of firm service at the fringes of various systems would be an acceptable approach." The newly defined contingency P2.1 requiring analysis of open ended line sections should allow load shedding of the load on the line section as suggested in the FERC order.</td></tr>
<tr><td colspan="3">Response: As P2.1 already includes footnote 12, the SDT is assuming that you are supporting the SDT position and thanks you for your support.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
San Diego Gas & Electric		In FERC Order 762, FERC rejected NERC's footnote (b) and urged "...NERC to develop modifications responsive to the Commission's directives in Order No. 693 and our concerns set forth in this final rule." The NERC SDT has done little to address FERC's concerns and instead has resubmitted the same document with additional language. Order 693 directed NERC to develop modifications to TPL-002-0, which clarify footnote (b). As redrafted, footnote (b) does not address FERC's concerns. For example, footnote (b) continues to use the term "Firm Demand," which describes all forms of demand whether served by the faulted element or not. On the contrary, "consequential load loss" is load, which is removed as a result of a fault. Clearly, these are different concepts and the new language does not comply with FERC's directive. FERC's position has been that non-consequential load loss through load shedding shall not be allowed as an exception to TPL-002-0. Also, FERC has stated that the interruption of Firm Transmission not be allowed as an exception. But, Footnote (b) continues to say, "Curtailment of firm transfers is allowed ...". Another inconsistency. Beyond the differences between what FERC directed NERC to do and what NERC did, as written, footnote (b) would introduce "stakeholder interests" into tranmission reliability even if those interests do not promote reliability. The TPL standards identify the Planning Authority and Transmission Planner as the entities responsible for meeting the standards and makes no mention stakeholders. To meet the reliability objectives of the standard, the Planning Authority and Transmission Planner are subject to Measures and the Compliance Monitoring Process. In FERC Order 762, FERC determined "...that openness and transparency do not alone ensure bulk electric system performance criteria will be met..." and was "...not persuaded that developing technical criteria is unachievable." Although FERC does not disagree with adding a stakeholder process, clearly, they do not endorse one and prefer a technical approach to creating the exception under footnote "b".

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single

Organization	Yes or No	Question 5 Comment
Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Consolidate Edison Co. of NY, Inc.		Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Response: The binary question of applicable use was well-vetted during the development of both the revised footnote 'b' and footnote 12. It is clear that some use, appropriately bounded, is the desire of industry and FERC. The SDT believes the proposed Attachment 1 provide the clarity sought by FERC in its remand of footnote 'b' and that the process is reasonable in its approach. No changes made.		
Manitoba Hydro		Please clarify if an entity must set up a stakeholder process if Firm demand interruption is not used as an element of the Corrective Action Plan. As I understand it, the footnote b in TPL 002 will be replicated in the other relevant TPL standards once it is approved. When it is included in the other TPL standards, will it be customized to each standard, or will it appear exactly the same in each standard? Footnote 12 of TPL-001 as currently drafted seems a bit disjointed or incomplete - i.e. its referring to Non Consequential Load Loss and then it refers you to an Attachment for the calculation of Firm Demand interruption without providing a connection

Organization	Yes or No	Question 5 Comment
		between the two concepts .
Response: A process would only be required if an entity allows or intends to utilize planned Load shed to meet the performance requirements for single Contingency (N-1) events. The commenter is correct that the final footnote 'b' and Attachment 1 will be replicated in the other currently-enforceable TPL standards – TPL-001, TPL-002, TPL-003 and TPL-004. The SDT acknowledges that the references to Firm Demand Interruption should reference Non-Consequential Load Loss. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes.		
TVA Transmission Reliability Engineering & Controls		Please see answer to question #1. TVA beleives that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Response: Please see response to Q1.		
BrightSource Energy, Inc. Utility System Efficiencies, Inc.		The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV inconsistent with P1.The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore

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		the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read:"Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read:"The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."
Response: 1 & 2. The SDT disagrees that the use of Footnote 'b' between P1 and P2 for EHV is inconsistent. The SDT believes that the system should be planned so that a fault on an EHV bus section or an internal fault on a non-bus-tie EHV breaker should not require planned Load loss to resolve system performance issues. The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made. 3. The definitions have not been revised, since the standard was approved by the NERC Board of Trustees and changes to those definitions are not in the scope of this project. No change made.		

Organization	Yes or No	Question 5 Comment
California Independent System Operator		The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value.The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard.

Response: 1 & 2. The SDT disagrees that the use of footnote ‘b’ between P1 and P2 for EHV is inconsistent. The SDT believes that the system should be planned so that a fault on an EHV bus section or an internal fault on a non-bus-tie EHV breaker should not require

Organization	Yes or No	Question 5 Comment
planned Load loss to resolve system performance issues. The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made. 3. The SDT disagrees that the attachment should be moved to the NERC Rules of Procedures. Inclusion of the Attachment 1 text within the Rules of Procedure might be appropriate for consideration if the process had wide impact on multiple NERC reliability standards. As such, since limited to use within the TPL standards, its inclusion directly within the TPL standard(s) is applicable. No changes made.		
Georgia Transmission Corporation		The current draft for Requirement 5 (R5) of the NERC Standard TPL-001-3 Draft 1 reads as follows:"Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."GTC has the following comments regarding TPL-001-3, R5:If the responsible entity has criteria for transient voltage response, along with criteria for acceptable system steady state voltage (including a pre-contingency high and low voltage limit, and a post-contingency high and low voltage limit), then having a steady state post-contingency voltage deviation criteria does not affect the reliability of the bulk electric system (BES). If the system response to a disturbance were to violate either the transient response criteria, or the steady state maximum/minimum voltage criteria, there is potential for loss of integrity of the BES. There is little to no potential for a loss of system integrity due soley to a violation of the steady state voltage deviation criteria. Therefore, Georgia Transmission Corporation requests that R5 not include a requirement to have criteria for post-Contingency voltage deviations.
Response: Requirement R5 requires the Transmission Planner and the Planning Coordinator to have established voltage criteria for their system. This set of criteria is necessary to ensure that the planners are evaluating the voltage excursions (transient and steady state) against their performance criteria. The standard requirements have not been revised since the standard was approved by the NERC Board of Trustees, and changes to those requirements are not in the scope of this project. No change made.		

Organization	Yes or No	Question 5 Comment
Salt River Project		The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read:"Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read:"The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."
Response: The definitions have not been revised since the standard was approved by the NERC Board of Trustees, and changes to those definitions are not in the scope of this project. No change made.		
MRO NSRF		The NSRF has concerns that over regulation of footnote "b" or "12" could cause lost opportunities for legitimate growth. An example condition would be the development of a large load in a relatively weak transmission area. Many times new large loads need open undeveloped areas to locate. Without the footnote "b" or "12" option, could an entity be forced to turn away legitimate load growth? The key being that an entity could serve the new large load under normal conditions with easy quick upgrades, but would need 5 - 7 years to construct additional transmission to meet N-1 conditions? Therefore the entity would need to turn away new growth because of over regulation on footnote "b" or "12".

Organization	Yes or No	Question 5 Comment
Response: The SDT does not believe that the proposed revision to footnote 'b' (or footnote 12) will restrict an entity's ability to serve new Load. The SDT has attempted to find a balance between being overly prescriptive and allowing entities the tools they need for planning purposes while responding to the remand from FERC. No change made.		
LCRA Transmission Services Corporation		The primary objection to Footnote 12 is twofold:1. Application to the P3 contingency. This contingency is a Category C contingency under the current NERC TPL-003 standard and allows for load shedding. Thus, the proposed standard revision is a significant and substantial increase in the reliability standard. 2. Use of the term "Firm Demand" as opposed to "Non-Consequential Load Loss." The NERC Glossary defines Firm Demand as "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions" and Demand as "The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time." Thus interruption of Firm Demand may not result in Non-Consequential Load Loss. Therm "Firm Demand" should be replaces with "Non-Consequential Load Loss."
Response: 1. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. 2. The SDT determined that it was appropriate to maintain the existing headers in the existing TPL standards and begin using "Non-		

Organization	Yes or No	Question 5 Comment
Consequential Load Loss" with the new TPL-001-2. No change made.		
Electric Reliability Council of Texas, Inc.		The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure). In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797). In a related compliance order, FERC reaffirmed its position. (130 FERC Â¶ 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the "fringes" of a system. (131 FERC Â¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service "at the fringes of various systems" would be acceptable. (131 FERC Â¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21. See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers...that anticipates no planned interruption." (Order 693 at P 1793)Against this background, NERC filed revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency

Organization	Yes or No	Question 5 Comment
		conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, (139 FERC Â¶ 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator.As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alterantively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region. Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission

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remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Southern Company		The use of load dropping should be limited to being only an interim solution while a project is being completed and nothing else can be done.
Response: An entity can choose to restrict the use of footnote 'b' to an interim solution but the SDT believes that there are instances where a long term use (permanent or near-permanent) of footnote 'b' may be appropriate. For example, the amount of Load involved versus the probability of occurrence might dictate that a long term use is in the best overall interests of the customers. No change made.		
Arizona Public Service Company		This process is too prescriptive and must be simplified.
Response: Without specific comments, the SDT is unable to respond.		
Ameren		To clarify, the Stakeholder Process should not be initiated until the amount of Firm Demand expected to be interrupted by the TP or PC as mitigation reaches a threshold of 10 MW. However, at that point, the Stakeholder Process should commence, but not without incorporating the need to obtain approvals from the stakeholders, regardless of the amount of load to be interrupted beyond the 10 MW threshold level, and regardless of the voltage level of the transmission elements involved in the contingency event(s). As drafted, the Stakeholder Process appears to be silent on receiving approvals to drop load of less than 25 MW. We believe that this is an invitation to trouble for the industry. For example, if a TP or PC were to have a contingency for which the mitigation is to interrupt 15 MW of Firm Demand, all the stakeholders would be called in just to inform them that their load is subject to

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		interruption, but their displeasure is not relevant, because the 25 MW interruption level had not been reached, and approval is not required. Thus, we believe that as drafted Stakeholder Process needs some additional work before we could support it.
Response: The stakeholder process is required anytime that Load is planned to be interrupted pursuant to footnote 'b'. Approval by the applicable regulatory authority or governing body responsible for retail electric service issues is required for planned interruptions greater than 25 MW. The SDT believes that this level is the appropriate balance to protect the interests of the customers without being unduly burdensome. No change made.		
Southwest Power Pool Reliability Standards Development Team		We agree the distinction between consequential and non- consequential is necessary. We don't agree that you should plan for non-consequential load loss/shed. You shouldn't have to interrupt firm service for n-1 contingency.
Response: The SDT believes that there are instances where use of footnote 'b' may be appropriate. For example, the amount of Load involved versus the probability of occurrence might dictate that a use of footnote 'b' is in the best overall interests of the customers. No change made.		
Nova Scotia Power		With regard to the application of Footnote 12 in TPL-001-3, the footnote is only applied to the contingencies in Table 1 involving loss of a Single Line with a 3 phase fault (P1) or opening of a line without a fault (P2-1). These are higher probability events relative to other types of contingencies, and Footnote 12 allows for loss of load for these events, but does not allow for loss of load for lower probability events that have the same results, such as P2-2 and P2-3. Take for example a single radial 345kV line feeding a small radial portion of the system, with a line end transformer and breaker between the transformer and the line. Application of Footnote 12 to only a P1 event (loss of the line on its own, or loss of the transformer on its own) but loss of the breaker between the line and the transformer would not be allowed, even though the result would be the same. Without applying footnote 12 to category P2-2 and P2-3 would mean that Footnote 12 is rendered moot (can never be used). Similarly, Footnote 12 should be applied to P4 and P5, essentially wherever Footnote 9 is applied, otherwise Footnote 12 can never be applied.

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Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT believes that the system should be planned so that a fault on an EHV bus section (or an internal fault on a non-bus-tie EHV breaker) should not require planned Load loss to resolve system performance issues. No change made.		
Northeast Power Coordinating Council		NPCC reviewed the posted documents, and has no comments for this posting.

END OF REPORT