Name (32 Responses)
Organization (32 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
Contact Organization (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (49 Responses)
Question 1 (38 Responses)
Question 1 Comments (45 Responses)
Question 2 (32 Responses)
Question 2 Comments (45 Responses)
Question 3 (30 Responses)
Question 3 Comments (45 Responses)
Question 4 (29 Responses)
Question 4 Comments (45 Responses)

Individual
Frederick R Plett
Massachusetts Attorney General
No
The SDT ignored a lot of feedback concerning the inappropriateness of a 75 MW threshold. IT remains inappropriate and an appropriate level should be decided by local stakeholder processes.
Yes
No
Don't buy the 75 MW or the 25 MW thresholds.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
PowerSouth Energy Cooperative
Yes
Yes
Yes
Change "does" to "do" in the last sentence of the first paragraph and in the first sentence of the last paragraph in Section III of Attachment 1.
We continue to recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
No
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No

Attachment 1 is overly burdensome and concerns local reliability issues better left to local regulators. A planned or unplanned loss of 25 MW is inconsequential to the reliability of the BES. The footnote could be simplified to exclude attachment 1 as follows: An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to 25 MW and notice must be given to applicable regulatory authorities or governing bodies responsible for retail electric service issues within 30 days of the completion of the assessment which includes the use of footnote 12.
No
Attachment 1 is overly burdensome and unnecessary.
No
Attachment 1 is overly burdensome and unnecessary.
Yes
If Attachment 1 must remain, Entergy would support the SERC PSS suggestion to limit the application of Attachment 1 (the stakeholder process) to only those situations where the non-consequential load at risk is above 25MW.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, and Footnote 12 of TPL-001-2), 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.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
No
Dropping load generally should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. NERC must acknowledge that jurisdictional authorities can decide on the parameters for planning events that do not have an impact on the reliability of interconnected BES . There are no limits on non-consequential load loss for Single Contingency P2-2 and P2-3 (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the extensive EHV Facilities in the Canadian regions of NPCC, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed. This comment was submitted for the last posting.
Yes
Yes
Individual
David Jendras
Ameren
Yes
Yes
Yes
We find no substantive changes to section III, and still believe that no objection from a regulatory body requires, at a minimum, a tacit approval.

Group
Southwest Power Pool Reliability Standards Development Group
Jonathan Hayes
Southwest Power Pool
Yes
Yes
Yes
Yes
Under section II items 3 and 4 the wording (frequency and duration) seems to implicate that the planners will be determining these events in a probabilistic manor. If the probability of these events is anything other than 0 planners will have to accommodate for those events in their planning assessments regardless of how small the probability is for that event.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Manitoba Hydro agrees that the changes add clarity to the footnote.
No
Any assessment or explanation is only speculation. Is the requirement any different? Item 5 raises an expectation that footnote 12 can only be used on an interim bases – this should be clarified.
Yes
Manitoba Hydro cannot support the Footnote B attachment which imposes a stakeholder process not required in Manitoba.
Individual
David Wang
SDG&E
No
Table 1, footnote b of TPL-002 allows the use of load shedding for the loss of a single element (Category B) under certain circumstances. SDG&E has been against the proposed changes because of the addition of a stakeholder process that allows outside entities to make reliability decisions which we would be held accountable for.
No
No
No
Individual
Bob Easton
WAPA-RMR
No
While Western agrees in general with what is proposed in Footnote b; I do not agree with stipluating 2 requirements in the proposed Footnote b: The 75 MW load threshold; the Attachment 1 Stakeholder process. The 75 MW seems low and NERC should condsider using a 300 MW threshold similar to that used in CIP-002 and EOP-004 requirements.
Yes
No
See response to Question 1.
Yes
I believe that the 75 MW limit is abetrary and could be too low given particular circumstances, like the maginitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. I also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Ordered 890 planning process.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program

Yes
Yes
Yes
No
Group
TVA Transmission Reliability Engineering and Controls
Tim Ponseti, VP
Bulk Transmission Engineering
Yes
Yes
Yes
We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance.
Group
Santee Cooper
Terry L. Blackwell
Santee Cooper
No
Santee Cooper will abstain from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. Santee Cooper is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, Santee Cooper will not vote against the revised footnotes.
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
Yes
The Public Utility District No.1 of Snohomish County will abstain from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. The Public Utility District No.1 of Snohomish County is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions (for details on the Public Utility District No.1 of Snohomish County's concerns please see the comments submitted during the initial ballot). However, in the spirit of moving this process forward, the Public Utility District No.1 of Snohomish County will not vote against the revised footnotes.
Group
seattle city light
paul haase
seattle city light
Yes
SCL abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. SCL is

concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions (for details onSCL's concerns please see the comments submitted during the initial ballot). However, in the spirit of moving this process forward, SCL will not vote against the revised footnotes.
Individual
Steve Alexxanderson P.E.
Central Lincoln
Yes
Central Lincoln has not paid much attention to this standard, since it is not applicable to this entity's registered functions. However, we are disturbed by the direction the standard is taking. The slides from the recent webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf) state that "The 75 MW cap will require construction of major Transmission projects." This is in direct conflict with the definition of "reliability standard" as provided in section 215 of the FPA where it states "...the term does not include any requirement to enlarge such facilities or to construct new transmission capacity..." The webinar slide does offer alternatives to construction, but we don't see those providing any reliability benefit. Some of the suggestions apparently only relate to contract language, which cannot possibly relate in any way to "reliable operation" as defined in section 215. Central Lincoln is is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions.
Individual
Milorad Papic
Idaho Power Company
Yes
Yes
Yes
No
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
We support the comments submitted by Central Lincoln
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
See response to question 4.
No
See response to question 4.
No
See response to question 4.
Yes
ERCOT believes that the revisions to the footnote b attachment are an improvement from the previous version. However, ERCOT does not believe that the SDT provided a technical rationale for disagreeing with the comments that we previously submitted. We fundamentally disagree with the approach of defining a stakeholder process in the attachment to a footnote in a reliability standard. While footnotes and attachments have been used in other standards we believe that this application is not appropriate. ERCOT believes that the footnote should be removed altogether as it does not meet the objectives of FERC Order 693. We also believe that FERC did not mandate that a stakeholder process be used. As stated in the January 8 NERC Industry Webinar, 90% of planning entities have not used the existing footnote b over a planning horizon of 13 years. To incorporate an attachment to a footnote with a complicated and prescriptive stakeholder process to address a few instances seems to be a least common denominator approach to planning which is opposed to FERC's direction. Consistent with the approach of TPL-001-2, ERCOT recommends raising the bar on reliability and removing the footnote from the standard.
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree

Midwest ISO
Individual
Kathleen Goodman
ISO New England Inc
No
There are jurisdictional issues with the footnote and attachment as written. These will be described in further detail throughout this document. The footnote itself states, “An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events.” A standard should not have requirements described as objectives, this language is extremely subjective.
No
Section II, 2.a, states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. The Transmission Planner in many cases will not be the appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Explaining effects on the “health, safety, and welfare of the community” is required under the footnote in Section II, 2.b. The same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can shed radial load with no assessment of health and welfare. In addition to the practical considerations listed, once again here the standard infringes on Section 215 responsibilities where State authority over the “safety, adequacy and reliability of the electric system in that state” is mandated. This section should be deleted. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. The planning process uses deterministic not probabilistic assessments. This section should be deleted.
The footnote states “Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either…”. Section 215 of the Federal Power Act clearly delineates Federal, State and Local authority. State and Local requirements should not be introduced into a NERC standard. In addition to the jurisdictional issues, proving that the “applicable regulatory authority or governing body” does not object is more difficult than proving that they simply approved the use of non-consequential load loss. The SDT should remove all references to State and Local authority from the standard. Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. At this point, it is too late to allow for any other alternative. The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. State and Local approval of practices called for in ERO Standards is inappropriate. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution.
In summary, this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act. The removal of references to State and Local authorities in the standard is required.
Individual
John Collins
Platte River Power Authority
No
Disagree with no change to the 75 MW threshold, but agree with the minor changes that were made since last posting. I request your consideration of a 300 MW threshold similar to that used in CIP-002 and EOP-004. Since there is a directive for some threshold, and in an attempt to reduce the likelihood of over-burdening smaller communities, the 300 MW level would be a more reasonable threshold for the BES.
Yes
No
See answer to Question 1.
No
Individual
Keith Morisette
Tacoma Power
Yes
Yes
Yes
While Tacoma Power appreciates NERC's attempt to address both footnotes with the same drafting team, Tacoma Power is voting negative on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. However, Tacoma Power would vote affirmative if a re-circulation ballot was limited strictly to footnote "b" in TPL-002-1c. TPL-001-2 considered new types

of outages not considered by TPL version 1, such as P2-1. Although TPL-001-2 was approved by the industry, the proposed modifications to footnote 12 in TPL-001-2 are significantly more onerous than footnote 12 in TPL-001-2. Furthermore, since TPL-001-2 is not yet enforceable, some Transmission Planners still do not realize that automatic relay actions are considered Non Consequential Load Loss. In addition, Tacoma Power identified over 100 MW of load in multiple locations that would be shed in accordance with footnote 12 in TPL-001-2. Unfortunately, the structure of the Section 1600 data request did not allow for the submittal of footnote 12 related data. Since it is clear that the potential impact of the footnote 12 revision has not been addressed due to the compressed timeline, Tacoma Power believes that by separating the two standards, NERC can meet the FERC mandated deadline for footnote b while still continuing the drafting process to achieve true industry consensus on footnote 12. Please note that FERC orders 693 and 762 require addressing only footnote "b" by the using the Expedited Standards Development Process. Earlier FERC orders discuss "single contingencies" as type Category B in TPL-002-1; FERC has not addressed Non Consequential Load Shedding for the lower probability "single contingencies" (i.e. P2-1) in TPL-001-2. Approving the revisions to footnote 12 would result in negligible reliability gains at an unreasonable cost for customers on the fringes of the power system, without affording local jurisdictional cost benefit analysis. Tacoma Power is also concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal Power Act. These revisions tread on customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. For details on Tacoma Power's concerns please see the comments submitted during the initial ballot. However, in the spirit of moving this process forward, Tacoma Power would vote to approve the revisions to solely TPL-002-1c if balloted separately from TPL-001-2. Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments.
Individual
Donald Weaver
New Brunswick System Operator
We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be approved by the appropriate jurisdiction
Group
ACES Standards Collaborators
Ben Engelby
ACES
Yes
(1) We continue to disagree with the 75 MW capacity limit threshold. There is no need for a 75 MW cap because registered entities and local-level policy makers are in the best position to determine an appropriate capacity limit, as stated in the FERC order and in previous feedback. However, if the drafting team decides to move forward with a cap, we suggest using a cap that would reflect all data points from the Section 1600 data request to be under the threshold. The findings to the data request contained a data point at 75.2 MW, which would be over the proposed threshold. We understand this data point, in essence, has been omitted because the use of non-consequential load shedding for the 75.2 MW data point is expected to terminate soon. If the drafting team intends to use the data that represents the actual usage of footnote ‘b’ by planning coordinators, then the team should take into account the highest data point and adjust the threshold to at least 76 MW regardless of the length of time the data point is needed. Again, local decision makers are better equipped to make this type of determination. (2) However, in the spirit of moving forward with this project we will support the changes and thank the drafting team for their efforts.
No
(1) Thank you for making the changes to Section II of Attachment 1. We believe the modification of removing “assessments” and replacing it with “explanation” provides more flexibility regarding how a registered entity can demonstrate the impacts the health, safety and welfare of the community. (2) However, we still believe that the word “alleviate” in bullet 5 requires the same actions as the word “mitigate.” There are instances where no action is required based on a variety of factors. We recommend the following: “Future plans, if necessary, to mitigate/alleviate the need for Non-Consequential Load Loss under footnote 12, unless a determination was made not to mitigate/alleviate, then an explanation why.”
Yes
Yes
(1) In regard to the changes relating to Demand-Side Management, we agree with the wording, “For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of a Contingency, or (2) Interruptible Demand or Demand-Side Management Load.” However, the most recent change has created some confusion by replacing “or” with “and” that potentially and inadvertently may exclude the use of DSM in all locations but on the facilities removed from service. This would render DSM ineffective. Now, the both (1) and (2) must occur in order to not be counted as Firm Demand. We recommend changing the wording back to “or” so each option (1) OR (2) is independently excluded from Firm Demand for footnote b. Connecting the options with the word “and” changes the meaning and requires entities to meet both option (1) and option (2) to be excluded from Firm Demand. Demand directly served by the Elements removed from service as a result of a Contingency should be excluded, as should Interruptible Demand or Demand-Side Management Load regardless of its location. A registered entity does not need to have both for the exclusion. (2) Thank you for the opportunity to comment.
Group
NARUC
Diane Barney

NARUC
No
As stated before, if there is no reliability threat to the bulk system there is no need for the 75 MW limit on the anticipated amount of load to be shed. As long as the regulator responsible for the retail load subject to being shed is notified of the situation, the situation can be appropriately addressed at the local level.
Group
MRO NSRF
WILL SMITH
MIDWEST RELIABILITY ORGANIZATION
Yes
No
The drafting team over specified the Section II stakeholder information process and continues to disregard comments that item 2b be removed from several utilities over several footnote “b” revisions. The goal of Attachment 1 as stated by the drafting team chair was to place “meaningful” parameters around footnote b. The words in 2b on “health, safety, and welfare” are beyond the scope of NERC standards, and are not defined sufficiently in the standard to make the requirement meaningful. The NSRF recommends that if the drafting team doesn’t eliminate 2b, they delete the words “on the health, safety, and welfare of the community” as going beyond NERC jurisdiction, FERC directives, and the SAR. The drafting team response that similar words exist in another standard is not a reason to the ambiguous words in the TPL Attachment 1.
No
The NSRF believes that the standards drafting team did clarify in the webinar that the 25 MW and 75 MW footnote “b” values were separate from interruptible load, and consequential load loss and would not be counted towards the 25 and 75 MW thresholds. However, the NSRF recommends that Attachment 1 also clearly contain an explicit statement “the 25 MW and 75 MW footnote “b” values are separate from consequential load loss, interruptible load, and are not to be counted towards the 25 MW and 75 MW thresholds.”
Yes
Some entities remain concerned over a potential conflict and mismatch of impacts introduced by Section III and the inclusion of non-regulated stakeholders versus NERC regulated entities. There was not a FERC directive to include section III. Section III overreaches the intent of the FERC order and the SAR to meet the FERC directive. The drafting team should show the specific FERC requirement and words in Order 693 that requires non-NERC regulatory reviews. The drafting team technically responded to a request that Section III be removed, but avoided the the fundamental issue. The fact that some existing non-NERC regulatory bodies may already have a consistent practice is not a reason to include non-NERC entities into a NERC framework. This creates a fundamental mismatch between NERC regulated entities that must follow NERC standards and stakeholders that are not compelled by NERC requirements. If Section III is not deleted, it is recommended that wording be added to allow the existing FERC Order 890 stakeholder meeting process be used to meet Attachment 1. Regulators attend these meetings and all stakeholders (including regulators) could be asked for their objections. If there was no response or a “lack of dissent”, this would be documented as meeting Attachment 1 to allow the use of footnote “b” without additional special procedures.
Group
Duke Energy
Greg Rowland
Duke Energy
Yes
Yes
Yes
No
Group
Hydro One Networks Inc.
Sasa Maljukan
Hydro One Networks Inc.
No
In this comment period Hydro One would like to reiterate its initial comments. Hydro One disagrees with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of

the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed. If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction."
No
As previously stated, we believe that the process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
No
The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1. If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 12, only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as "for those planning events where the use of footnote 12 is referenced." We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
Yes
As previously stated in our response to Question #1, Hydro One would like to reiterate our position presented during the initial comment period. We believe that the SDTs response to our initial comments did not correctly address the issues because it did not recognize the Reliability Standards framework that is effective in the Province of Ontario and possibly other Canadian provinces.
Individual
Michiko Sell
Public Utility District No. 2 of Grant County, WA
No
GCPD abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. GCPD is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal Power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, GCPD did not vote against the revised footnotes.
Individual
Michael Moltane
ITC
MISO
Yes
Yes
Yes
Yes
While ITC is voting yes for this "successive ballot", we are doing so in the interest of ensuring that TPL 001-2 becomes fully effective as soon as possible. TPL001-2 is a major improvement to previous standards and insuring it becomes fully effective is important to ITC and the industry. However, we have concerns that we would like to be noted. Because footnote B has been highlighted and expanded, there is the possibility of future "unintended consequences". It is highly likely that interveners or others may attempt to stop or slow down needed corrective action plans, that do not rely on load shedding, by suggesting that planners use this stakeholder process before proposing projects. We suggest both NERC and FERC be prepared to deal with these unintended consequences. We also concur in entirety with the comments MISO is proposing to make for this project. They are consistent with past comments ITC has made and do discuss in some detail the potential "unintended consequences" this detailed footnote may cause.
Group
Western Area Power Administration - Transmission Owner
Lloyd A. Linke
Western Area Power Administration

No
While Western generally agrees with the proposed modification to footnote b, Western does not support the 75 MW threshold and Attachment 1 Stakeholer process. The 75 MW threshold seems to low and if a threshold it needed the drafting team should consider using a 300 MW threshold similar to that used in CIP-002, EOP-004, DOE OE-417 reporting, and NERC event analysis process. The stakeholder process seems to be duplicative, considering there FERC Order 890 planning process.
Yes
No
See answer to Question 1.
Yes
Western believes that the 75 MW limit is arbitrary and could be to low given particular circumstances, like the magnitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. We also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Order 890 process.
Individual
Mark Westendorf
MISO
No
MISO does not object to the changes made to the body of the footnote since the previous draft. However, as a general matter, MISO cannot support the current language of Footnote 12. Because the intent of the TPL standards is not to rely on non-consequential firm load shedding after a single contingency event, MISO does not agree that footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2 should be included in these standards. Nonetheless, if these footnotes are included, MISO agrees that there should be some limitation on how much firm load shed is allowed under these footnotes and would not object to the proposed 75 MW level if the footnotes are included.
No
Regarding the use of “explanation” in place of “assessment,” MISO understands that the purpose of this change is to reduce the need for entities to hire expensive consultants and to incur other substantial costs in assessing demographic data and impacts on an affected area. However, as written, this word change potentially places more of a burden on responsible entities. An assessment is an analysis performed using available facts and data while an explanation implies full knowledge. MISO therefore recommends that “assessment” be retained and that a footnote explaining the meaning of that term be added. More generally, however, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this time. Please refer to our comments under Question 4 for a more detailed description of these concerns.
No
MISO does not object to the changes made to Section III. However, more generally, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this time. Please refer to our comments under Question 4 for a more detailed description of these concerns.
Yes
As previously stated, it is the general intent of the existing TPL-002-1 standard and proposed TPL-001-2 standard to not rely on any shedding of Non-Consequenital Load to meet a single contingency event. Accordingly, MISO submits that footnote b of TPL-002-1 and footnote 12 of TPL-001-2 should be struck. However, in the event that the footnotes in question are not eliminated, the footnote should be narrowly focused only on those situations for which the original footnote was developed, i.e., the interruption of service to radial customers or some local area Network customers connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. MISO therefore proposes the following alternate language for footnote b and footnote 12 to ensure it is not misapplied: “An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load shed cannot be used to avoid cascading outages or to maintain system stability. Non-consequential load shed also cannot be used to avoid a thermal loading or voltage limit violation on an extra high voltage (EHV) facility. When Non-Consequential Load Loss is utilized within the transmission planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the following circumstances: • Non-consequential Load shed is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event. • Non-consequential load shed is allowed for load within a local area served by not more than two Transmission Circuits and/or Transformers to avoid a thermal loading issue or voltage issue within the local area, including the Transmission Circuits and/or Transformers directly supplying the local area, for a loss of a single element within the local area, including one of the Transmission Circuits or Transformers directly supplying the local area, so long as there are no thermal loading or voltage violations outside the local area.” MISO believes the language above would ensure the continuing reliability of the Bulk Electric System by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. In addition, MISO has significant concerns regarding use of a stakeholder process to determine if non-conseqeuntial load shedding is appropriate following a single contingency event, as expressed in MISO’s comments on previous drafts of this Project. In particular, MISO has concerns regarding whether such a stakeholder process could be sufficiently open and transparent given the many, competing interests of the responsible entity and affected stakeholders. Without such sufficient openness and transparency, it is likely that stakeholder processes will not result in consistent determinations of the appropriateness of the application of footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2. Stated differently, MISO is concerned that such stakeholder processes will always be subject to the biases of the participating parties, with the sheer number of parties determining the outcome of the process. As an example, should a particular process be dominated by parties that may be responsible for payment of upgrades but that are not impacted by the alternative load shed, those stakeholders impacted by the alternative load loss would be relegated to a minority position, resulting in majority-imposed stakeholder decisions to shed load. On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to

the extent those stakeholders pay only a small part of the upgrade costs, they will always choose to avoid load shed – even if such decision requires a potentially costly upgrade. Consequently, MISO has concerns that the inclusion of a requirement for a fair and impartial stakeholder process to determine if and when load shed is acceptable to assist in satisfying a single contingency standard is not realistically attainable. MISO therefore recommends that Attachment I be eliminated and that the footnotes either be eliminated or replaced with the modified version above.
Individual
Michael R. Lombardi
Northeast Utilities
No
Northeast Utilities does not support the use of non-consequential demand interruption throughout the planning horizon. Even with the 75 MW limit, NU believes that this language seems to encourage operational workarounds and adds burdens for operators of the system. Lastly, NU believes this use of non-consequential load loss during the planning horizon is not consistent with planning a highly reliable bulk electric system and thus does not support non-consequential load loss for planning purposes.
Individual
Patricia Robertson
BC Hydro
Yes
BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c – System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a – Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments: 1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Individual
Teresa Czyz
Georgia Transmission Corp.
Yes
Since this question refers to both footnote b (TPL-002-1c) and footnote 12 (TPL-001-2a), and the changes to the footnotes are not identical, the question should be split into two. Regarding footnote b: An excerpt from footnote b reads “For purposes of this footnote, the following are not counted as Firm Demand (1) Demand directly served by the Elements removed from service as a result of the Contingency …” However, what is being described is in fact Firm Demand (That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions) that is Consequential Load Loss (All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.). Therefore, why not use the terms Consequential Load Loss and Non-Consequential Load Loss? Regarding footnote 12: The replacing the NERC defined “Contingency” event with the undefined “planning” event necessitates a new definition. The intent of the change is unclear.
Yes
Yes
Group
Southern Company
Shih-Min Hsu
Southern Company Services, Inc
Yes
Yes
Yes
Yes
Footnote b contains no technical basis for allowing load dropping. It is completely based on an administrative procedure. This is not

responsive to paragraphs 17 and 32 of the FERC remand order. A technical basis has to be proposed. The "temporarily radial" concept that was proposed in earlier drafts will address this problem. It will give a technical basis for when load dropping would be allowed. If a technical basis is developed like FERC requires, then there is no need for a stakeholder process. The stakeholder process is not a bright line criteria which can be enforced; it will change depending on the make-up of stakeholders and therefore create inconsistencies across the grid. This approach should never be used in a reliability standard. NERC adopted the ANSI standard process as the bench mark in developing its reliability standards. ANSI does not use stakeholder processes. We propose that the stakeholder process be eliminated. Create a technical basis for when load dropping can be utilized. Keep the 75 MW maximum amount of load that can be dropped.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Hydro-Québec TransÉnergie (HQT) remains unconvinced that a MW threshold needs to be part of footnote 12. This is not a BES reliability issue but only a matter of service continuity to be addressed by TO/PA/RC with local regulatory authorities.
No
HQT still considers that the non application of footnote 12 to categories P2 (breaker fault), P4 (stuck breaker) and P5 (failure of a non redundant relay) is not correct, when the footnote is applied to other categories such as P3, P6 and P7 (loss of double-circuit lines). The SDT has indicated that the applicability of footnote 12 to categories P2, P4 and P5 is not included in Project 2012-11. However, looking at related Project 2006-02 where footnote 12 was brought up to Table 1, the matter of applicability was not discussed in detail and the SDT did not clearly explain why Non-Consequential Load Loss was not allowed for contingencies less frequent than those for which it is allowed (internal breaker faults or stuck breakers are less probable than double-circuit line faults). Discussion on this matter should not be dismissed.
Individual
Clay Young
SCE&G
No
Comments previously submitted.
No
Comments previously submitted.
No
Comments previously submitted.
No
Individual
Michael Falvo
Independent Electricity System Operator
No
Please note that the Independent Electricity System Operator (IESO), an RTO/ISO registered under Industry Segment 2, has filed an appeal with respect to NERC's response to our similar comments submitted to the previous ballot on this project. We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. To recognize NERC's role as the ERO for Ontario and the Memorandum of Understanding between NERC and the Ontario Energy Board, the IESO proposed replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico). Under this language, both the amount of non-consequential load loss, and the process under which that amount was arrived at, including stakeholder consultations, would be determined by the relevant Canadian jurisdiction, in this case Ontario. This change will make the standard acceptable in Ontario's legislative framework, in which NERC standards come into force automatically unless, by order of the Ontario Energy Board, a standard is stayed and remanded back to NERC for further consideration. The responses to the IESO's comments in the previous ballot were inaccurate as to this key feature of the Ontario reliability framework, as addressed in the IESO appeal. An alternate solution to this issue, which would • be consistent with the intent of the responses to the IESO comments on the previous ballot, • respect the Ontario reliability framework, and • resolve the IESO January 9, 2013 appeal; and is appropriate given that these changes are being driven by a U.S. FERC remand order to NERC, would be to make the following highlighted clarifications to footnotes 'b' and 12: With respect to Standard TPL-002-1c — footnote 'b' b) An objective of the planning process is 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 For purposes of this footnote, the following are not counted as Firm Demand will be interrupted

if itt is: (1) Demand directly served by the Elements removed from service as a result of the Contingency, orand (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities 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. In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for U.S. registered entities. With respect to Standard TPL-001-2a — footnote 12: 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for U.S. registered entities.
No
No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, for the reasons described in Q1.
No
The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments and supporting reasons. If this section must deal with a review of the use of footnote ‘b’/’12’ to ensure that there are no widespread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote ‘b’/’12’, only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. The use of footnote ‘b’/’12’ should not be limited to the Near-Term Planning Horizon. We propose that the words “in Year One of the Planning Assesssment” be deleted. Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as “for those planning events where the use of footnote ‘b’/’12’ is referenced”. We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
(1) The IESO reiterate its support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no widespread adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. 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 (including 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 application of footnote ‘b’/’12’ that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote ‘b’/’12’ is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. There continues to be confusion as to this inconsistency, and to how this is to be applied (as discussed at the last webinar). (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote ‘b’, and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels. (4) The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, as described in Q1 and for the reasons stated therein. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote ‘b’/’12’ should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase “the Near-Term Transmission Planning Horizon of” be deleted from the opening paragraph.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP
Group
Iberdrola USA
John Allen
Rochester Gas & Electric

No
See comment to question 4 below.
No
See comment to question 4 below.
No
See comment to question 4 below.
Yes
The reasons for the “negative” vote are enumerated in our prior comments. In summary: 1. Attachment 1 is cumbersome and inappropriate, and should be stricken entirely. 2. All non-consequential load loss for all single-element contingencies should be temporary, with an action plan to avoid such load loss in the future. 3. All actions following single-element contingencies should be an attempt to restore lost customer service, not interrupt more customers.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
No
Individual
Vijayraghavan bangalore
Pacific gas and Electric Comapny
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. 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. 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.
No
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?
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 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”.
No
Group
Tri-State G&T
Chris Pink
Chris Pink
No
1. In the last submittal for comments, the following comment was made: It was not clear how transmission projects with long lead times (such as T-lines) would be handled by “Footnote b.” In other words, it is not clear if it is acceptable for a TP to plan for

shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in “Attachment 1” when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. The The Standard Drafting Team (SDT) provided the following response: Any instance of proposed load shed for a single Contingency situation in a Planning Assessment must meet the conditions of footnote ‘b.’ No Change made. From the above comments, we believe there is a situation where the Bulk Electric System (BES) reliability is compromised while stakeholder process proceeds.
No
2. As stated previously, NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in “Attachment 1.” As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. The SDT acknowledged this by stating that “the NERC Functional Model is a guideline for activities required of cited functional entities.” As such, we still believe that obligations should not be required of entities outside of the NERC Functional Model descriptions.
No
3. Previously, it was commented that it is unclear how section III of “Attachment 1” would be applied to entities that only deliver wholesale electric service and not retail electric service. The response provided by the SDT stated the following: The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of footnote must go through the stakeholder process. No change made. If the wholesale customer is one of the stakeholders, the standard needs to add wholesale customers into the language as part of Attachment I. For example, it should read as follows: Coordinator must ensure that the applicable regulatory authorities, wholesale customers, or governing bodies responsible for retail electric service issues does not object to the use of Firm Demand interruptions under footnote ‘b’…
Group
National Grid
Michael Jones
National Grid
Yes
We are accepting the standard as written because our current practices are better then the prescribed maximum limit. However, we believe the appropriate limit should be determined on a case by case basis with the state regulator input. This standard as written, does give us the flexibility to do this.
Individual
Alice Ireland
Xcel Energy
Yes
While we are not satisfied with the responses to our previous comments, we have chosen to not reiterate them here. Instead, we feel that the need to continue with any modification to Footnote b seems moot considering FERC's recent approval of the revised BES definition. Specifically, we believe exclusions E1 and E3, regarding radial systems and local networks, resolves FERC's original directive on ambiguity with footnote b. We recommend the team consider abandoning this project, and request that NERC staff request relief from FERC on the related directives, as they have been overcome by the modified BES definition.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing