NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

June 7, 2011

Joseph H. McClelland
Director, Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Docket No. RM11-18-000

Dear Mr. McClelland:

Attached are the responses of the North American Electric Reliability Corporation ("NERC") to the Federal Energy Regulatory Commission's ("FERC") Office of Electric Reliability's May 17, 2011 letter to NERC requesting additional information regarding NERC's March 31, 2011 petition seeking approval of the proposed TPL Table 1, Footnote b (the "May 17 letter"). Proposed TPL Table 1, Footnote b, addresses one of the Commission's directives in Order No. 693, and does so in a manner that is at least as efficient and effective as the approach described in the directive.

NERC's proposed draft TPL Table 1, Footnote b appears in four Reliability Standards proposed in NERC's March 31 petition (TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A); TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B); TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C); and TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)).

Proposed Table 1, Footnote b reads as follows:

> 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 redispatch 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 address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject

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to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Proposed Table 1, Footnote b, addresses the directives from Order No. 693, as clarified in the Commission's June 11, 2010 order denying rehearing and granting partial clarification. The Commission did not absolutely prohibit planning to shed firm load in all circumstances. On that issue, the Commission stated:

> 21. [] the above passage from Order No. 693 acknowledged that the ERO could consider the comments of Entergy and Northern Indiana regarding planning for the loss of firm service "at the fringes of various systems," as NERC now characterizes the issue.[f.n. omitted] However, the Commission expressed concern that whatever approach is chosen by the ERO does not reflect a "lowest common denominator," i.e., "[t]he proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice – the so-called 'lowest common denominator' – if such practice does not adequately protect Bulk-Power System reliability." [f.n. omitted] Moreover, the Commission, in the same passage from Order No. 693, then provided a clarification that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances. We believe that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service "at the fringes of various systems" would be an acceptable approach. Thus, the Commission did not dictate a single solution as NERC and others now claim. In any event, NERC must provide a strong technical justification for its proposal.[1]

NERC addressed FERC's instruction to clarify Footnote 'b' regarding load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state. However, NERC did not delete in its entirety the ability of an entity "to plan for the loss of non-consequential load in the event of a single contingency." Rather NERC crafted a footnote the meets the Commission's objective while simultaneously meeting the needs of industry and respecting of jurisdictional bounds. No longer can those registered with NERC as Planning Authorities or Transmission Planners plan to interrupt Load under a Category B (N-1) Contingency event unless the registered functions meet the specified conditions detailed in the footnote.

As permitted by Order No. 693, stakeholders, under the supervision of NERC, developed a responsive, equally efficient and effective alternative to the directives articulated in Order No. 693. The proposed footnote was successfully balloted using all FERC-approved standards development processes in place at the time of development, in accordance with NERC's filed and approved Rules of Procedure as implemented and overseen by the NERC Standards Committee. The NERC Board of Trustees reviewed and approved the proposed Footnote b on February 17, 2011. NERC's March

[1] *Order Denying Rehearing and Granting Partial Clarification, Denying Request for Stay, and Granting Extension of Time*, 131 FERC ¶61,231 at P 21 (June 11, 2010).

31 petition for approval of the proposed Footnote b responded to the fifteen criteria FERC uses to approve a Reliability Standard.[2]

After extensive consideration during the standards development process of the Commission's suggestion in Order No. 693 that NERC develop a case-specific exceptions procedure, NERC, through the standards drafting team and the ballot pool, chose a response that NERC believes is at least as efficient and effective. As described in the March 31 petition, NERC believes that an ERO-sponsored planning process is not likely to be efficient or effective because of extensive jurisdictional issues between NERC, FERC, and the many authorities having jurisdiction that would have to be resolved in perhaps forty-eight of the fifty states, not to mention similar relationships with the provinces in Canada, before implementation could occur. A NERC-centered process would at best duplicate planning actions going on elsewhere (where resource allocation decisions are actually being made), and such a process could lead to inconsistent results. It appeared to the industry and to NERC that a more reasonable and expeditious path would be to rely on existing stakeholder processes, a large majority of which are driven by other FERC orders. Such processes would be more likely to engage the appropriate local-level decision-makers and policy-makers. For these reasons, NERC's March 31 petition proposed an efficient and effective alternative in responding to the directive and implementing Footnote b planned outages by leveraging current, existing stakeholder processes already established to address transmission planning choices.

FERC already mandates transmission planning processes through specific requirements addressed in Order No. 890 and subsequent Orders. While the Order No. 890 process is one example of an existing stakeholder process that could include a case-specific review of any planned use of Footnote b, other processes also exist that could include a similar review. For example, state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues could serve to provide a case-specific review of the planned interruption of Firm Demand. Some additional examples of processes covering specific regions of the country are the South Carolina Regional Transmission Planning process; the Southeast Inter-regional Participation process; the New York ISO process; and the California ISO process.

Relying on existing stakeholder processes to implement Footnote b will provide mechanisms for NERC and the Regional Entities to effectively monitor an entity's planned interruptions of Firm Demand. Proposed Table 1, Footnote b recognizes that it is generally inappropriate to plan to interrupt Firm Demand to meet reliability performance metrics. In limited circumstances, an entity may rely on planned load shedding. The magnitude and timeframe for which the entity plans to rely on load shedding will be limited to circumstances where its use is documented and subject to an open and transparent stakeholder process. In such cases, the Compliance Enforcement Authority ("CEA") will be able to review the entity's implementation of Footnote b through audits and spot checks.

In an audit or spot check of an entity, one of the first questions asked will be whether the entity planned on interrupting Firm Demand to meet reliability performance requirements. If so, the entity will be required to provide all relevant documents pertaining to such transmission planning

[2] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

decisions. This documentation should include the specifics of what load will be shed and under what circumstances. The entity will also be required to provide a description of other alternatives that the entity considered and a description of the stakeholder process in which the decision to rely on load shedding was made. Additionally, the audit or spot check will include a discussion of the activity or participation by the relevant governmental authority with jurisdiction over the matter. Based on all of this information, NERC or the Regional Entities will be able to determine whether the decision by the entity to rely on load shedding to meet performance requirements was reasonable given the circumstances. For additional detail regarding how compliance with Footnote b will be monitored by NERC and the Regional Entities, see NERC's responses to questions 3, 4, 5, 6, 7, 8, 9, and 10 of FERC's May 17 letter.

NERC recognizes that this letter and the enclosed responses to the staff's questions provide more detail and explanation than is provided in the March 31 petition, but NERC does not understand the import of the staff issuing what it characterizes as a "deficiency letter" to request additional information. Unlike with tariff filings (where deficiency letters are most often used), there is no clock running on NERC's March 31 petition. Moreover, the May 17 letter does not explain how the filing is deficient. Rather, the May 17 letter poses a series of questions requiring justification for why NERC did not adopt the specific ERO-centric, case-by-case exceptions procedure suggested by the Commission in Order No. 693. NERC is uncertain what opportunities exist, if any, for stakeholders to comment on the questions posed in the deficiency letter and NERC's responses to that letter. Given the extensive stakeholder process that has been employed in developing the revisions to Footnote b, it will be important to continue to provide opportunities for stakeholder comment as the Commission considers action on the March 31 petition. Therefore, NERC requests that the Commission issue notice of these responses to the May 17 letter and provide an opportunity for stakeholder comment on the responses.

For the reasons stated in NERC's March 31 petition, in this letter, and the attached responses, the approach proposed in Footnote b is equally efficient because many of the stakeholder processes that will be used in Footnote b planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions. More localized decision-making is preferable to an ERO-centric exceptions process because of the inevitable debate about cost which is implicit in planning decisions. Additionally, the approach is effective because the ERO process will be able to monitor any planned use of Footnote b through audits of the transmission planners. These audits will ensure that use of Footnote b is being addressed under the guidelines established there. For these reasons, the approach presented in NERC's petition that is contained in the proposed Footnote b fulfills the FERC directive in an equally efficient and effective manner, and is achievable in a reasonably short time frame having gained the acceptance of the industry. Proposed Footnote b raises the bar because it now requires full documentation and disclosure of planning choices impacting reliability.

Please contact me if you have questions or need additional information.

<u>*/s/ David N. Cook*</u>
David N. Cook
Senior Vice President and General Counsel
North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	**)**	**Docket No. RM11-18-000**
RELIABILITY CORPORATION	**)**	

RESPONSE OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
TO THE FEDERAL ENERGY REGULATORY COMMISSION'S MAY 17, 2011
LETTER REQUESTING ADDITIONAL INFORMATION REGARDING NERC'S
REQUEST FOR APPROVAL OF FOUR TRANSMISSION PLANNING SYSTEM
PERFORMANCE RELIABILITY STANDARDS

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June 7, 2011

Question 1:

In the June 11 Order, the Commission determined that the standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency and directed that footnote 'b' be clarified. The Commission further clarified in P 21 that an entity may seek a regional difference to the Reliability Standard from the ERO for case specific circumstances, or the ERO could develop a case-specific exception process that can be technically justified, to plan for the loss of firm service "at the fringes of various systems." Please explain and justify how the proposed modification to footnote 'b' that allows interruption of Firm Demand is responsive to these directives.

NERC Response:

Project 2010-11 was initiated on April 14, 2010 to clarify TPL Table 1, Footnote 'b', as required in FERC Order No. 693 and as mandated in FERC's subsequent order dated March 18, 2010, setting a deadline for compliance specific to the Footnote 'b' clarification originally described in Order No. 693 ("March 18 Order").[1] On June 11, 2010, FERC issued a subsequent order in response to re-hearing and clarification requests which extended the compliance filing timeline for nine months from the original date of June 30, 2010 to March 31, 2011.[2]

In Order No. 693 at Paragraph 1794, the Commission stated that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load.[3] The Commission also noted that the ERO should consider the comments of Entergy and Northern Indiana during the standards development process.[4] The Commission further stated that it: "strongly discourage[s] an approach that reflects the lowest common denominator."[5] However, the Commission further clarified that the ERO **could** address this issue by allowing entities to seek regional differences for case specific circumstances or develop a case-specific exception process.[6]

The standard drafting team, in revising the Reliability Standard, considered these options and, based in part on the feedback obtained at the NERC Technical Conference on Footnote b held in Charlotte, North Carolina on August 10, 2010, determined that a case-specific exception process or other process requiring approval by FERC or NERC would create undesirable delays and uncertainty in the transmission planning process. Accordingly, the standard drafting team developed a more efficient approach to addressing the directive by utilizing an open and transparent stakeholder process that many entities already have in place in order to comply with Order No. 890. This is vastly preferable and more efficient than creating a new process which the ERO would have to administer across all 50 U.S. states and each province in Canada. This

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1 *Order Setting Deadline for Compliance,* 130 FERC ¶ 61,200 (2010) at P 2, 10.

2 *Order Denying Rehearing and Granting Partial Clarification, Denying Request For Stay, And Granting Extension Of Time*, 131 FERC ¶ 61,231 (2010) at P 3.

3 *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) ("Order No. 693") at P 1794, *Order on Reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).

4 *Id.*

5 *Id.*

6 *Id.*

approach presents an equally efficient and effective alternative to addressing the directive because it ensures that interested stakeholders have an opportunity to voice concerns and have these concerns addressed through processes they are familiar with and equipped to interact with.

As noted, FERC already mandates transmission planning processes through specific requirements addressed in Order No. 890 and subsequent Orders. While the Order No. 890 process is one example of an existing stakeholder process which would require a case-specific review of any planned use of Footnote b, other processes also exist which would require a similar review. For example, state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues could serve to provide a case-specific review of the planned interruption of Firm Demand. Some additional examples of processes covering specific regions of the country are: the South Carolina Regional Transmission Planning process; the Southeast Inter-regional Participation process; the New York ISO process; and the California ISO process. However, the processes initiated under Order No. 890 largely covers transmission planning processes for reliability purposes.

Order No. 890 was intended, in strengthening the pro forma open-access transmission tariff, to reduce opportunities for discrimination in transmission planning and increase transparency in the rules applicable to planning and use of the transmission system. Order No. 890 requires that an open, transparent, and coordinated transmission planning process be utilized by requiring transmission providers to open their transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.

Through Order No. 890, FERC has extensive experience at creating and managing nationwide stakeholder processes. Order No. 890 already mandates that processes with the following requirements, which are either directly or indirectly applicable to the transmission planning process, be met through the stakeholder processes. Some of these requirements are:

- Transmission Providers must post a "strawman" proposal for compliance with each of the ***nine planning principles***[7] adopted in the Final Rule.[8] This may be posted on the Transmission Providers website or its OASIS site (P 443);

[7] Emphasis added (bold, italics) to those Order No. 890 requirements that are non-rate terms related to transmission planning.
[8] These nine planning principles are: (1) Coordination -- transmission providers must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis; (2) Openness – transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers and state authorities); (3) Transparency – transmission providers are required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans; (4) Information Exchange -- network transmission customers are required to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load; (5) Comparability – after considering the data and comments supplied by market participants, each transmission provider must develop a transmission system plan that (a) meets the specific service requests of its transmission customers and (b) otherwise treats similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning; (6) Dispute Resolution – transmission providers must propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third party neutral; (7) Regional Participation – each transmission provider is required to coordinate with interconnected systems to (a) share system plans to ensure that they are

- Transmission providers that have not been approved as ISOs or RTOs, and whose transmission facilities are not under the control of an ISO or RTO, must submit FPA section 206 filings that contain the ***non-rate terms*** and conditions set forth Order No. 890. These filings need only contain the revised provisions adopted in Order No. 890. Transmission providers utilizing the optional implementation FPA section 205 filing described above, need only submit tariff sheets necessary to implement the remaining modifications required under the Order No. 890, *i.e.*, modifications related to tariff provisions that did not implicate previously-approved variations (P 135);

- Each transmission provider is directed to post a draft of the attachment to its OATT governing ***transmission planning*** on its OASIS, or on its website if it does not have an OASIS (*see, Order Extending Compliance Action Date and Establishing Technical Conferences*);

- ISOs and RTOs, and transmission providers located within an ISO/RTO footprint, submit FPA section 206 filings that contain the ***non-rate terms*** and conditions set forth in the Final Rule. These filings need only contain the revised provisions adopted in the Final Rule or a demonstration that previously approved variations continue to be consistent with or superior to the revised *pro forma* OATT (PP 157, 161);

- Submit compliance filings with Attachment K (Planning) of the *pro forma* OATT or RTOs and ISOs file a demonstration that their ***planning processes*** are consistent with or superior to the planning principles in the Final Rule (*see*, PP 140, 422, and *Order Extending Compliance Action Date and Establishing Technical Conferences*);

- N/A Transmission Providers must file a revised Attachment C to incorporate any changes to ***NERC's*** and NAESB's reliability and business practice standards to achieve consistency in ATC within 60 days of completion of the NERC and NAESB processes (P 325); and

- After the submission of FPA section 206 compliance filings, transmission providers may submit FPA section 205 filings proposing rates for the services provided for in the tariff, as well as ***non-rate terms and conditions*** that differ from those set forth in the Final Rule if those provisions are "consistent with or superior to" the *pro forma* OATT (P 135).

The approach in the proposed Footnote b presents a step forward in the improvement of the transmission planning Reliability Standard and does not reflect a least common denominator

simultaneously feasible and otherwise use consistent assumptions and data and (b) identify system enhancements that could relieve congestion or integrate new resources; (8) Economic Planning Studies – the transmission planning process under the pro forma OATT must consider both reliability and economic considerations. The purpose of this principle is to ensure that the latter is considered adequately in the transmission planning process; (9) Cost Allocation for New Projects – Planning processes must address the allocation of costs of new facilities (i.e. Transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs).

approach. Because many of these stakeholder processes are already in place, this approach presents an efficient way to ensure that the ERO and all regulatory bodies have an opportunity to clearly understand and evaluate decisions affecting bulk power system reliability that, under the current standards, could be made by a single entity and not shared with others. An alternative, case-specific ERO process would create unnecessary burden on the industry by creating another review process by the ERO that could potentially overstep NERC's section 215 mandate. Besides the additional resources being expended on a duplicative process, an ERO-specific process would undoubtedly lead to conflicts among federal, provincial, state and local governing bodies that have jurisdiction over various parts of the planning, siting and construction process. Finally, an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority.

Accordingly, the approach proposed in Footnote b is equally efficient because many of these processes are already in place, as envisioned by FERC in Order No. 890, that may be utilized as the TPL Footnote b open and transparent stakeholder process. Additionally, the approach is effective because any planned use of Footnote b will go through a case specific review under the guidelines established for stakeholder process. For these reasons, the approach presented in NERC's petition that is contained in the proposed Footnote b meets the FERC directive in an equally efficient and effective manner that does not present a least common denominator approach.

Question 2:

Proposed Footnote ‘b’ states that “in limited circumstances, Firm Demand may need to be interrupted to address [bulk electric system] performance requirements” within the transmission planning process. Please explain this statement and fully describe the contemplated restrictions or limited circumstances where Firm Demand interruptions would be permissible (e.g., magnitude, duration, voltage level, location, etc.).

NERC Response:

Within Footnote b, it is recognized that an objective of the planning process should be to minimize the likelihood and magnitude of planned interruptions of Firm Demand. This statement reinforces that the objective of planning for Category ‘b’ events should not be to interrupt Firm Demand, but also recognizes that there may be topological or system configurations where allowing planned interruptions of Firm Demand may provide more reliable service than a strict prohibition on interrupting Firm Demand.

With the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned interruption of Firm Demand for Category ‘b’ events within the framework of Reliability Standards across all of North America. Within the standards development process, a variety of limits were discussed and considered. These included a limit on the magnitude of load being interrupted and the likelihood that load would need to be interrupted (based on load shape and probability of the outage occurring). While setting a certain magnitude of firm demand was evaluated by the standard drafting team, there was not analytical data to support a single value and therefore, a single value was viewed as arbitrary. After extensive discussions, the drafting team determined that, even if more data were made available, a single level of Firm Demand would not have been supportable that could address every planning situation in North America.

Question 3:

Proposed footnote 'b' states that interruption of Firm Demand is limited, among other things, to "circumstances where the use of Demand interruption are documented, including alternatives evaluated...." Please explain in detail the circumstances and "documentation" that would be required. Specifically, what technical criteria would be applied, how alternatives would be evaluated, and whether both would be included in the documentation.

NERC Response:

The proposed Footnote b states that when planned interruption of Firm Demand is utilized within the planning process ***to address Bulk Electric System performance requirements***, such planned interruption is limited to circumstances where the use of planned Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

The Footnote b in the currently-effective standards would require the planning coordinator or transmission planner to determine where to utilize Footnote b without disclosure in a public forum. In contrast, the proposed footnote would require the utility to make such decisions visible in a stakeholder process. Such a process would identify the technical criteria justifying why the planned interruption is an appropriate planning solution. This would make such instances visible to the affected parties and to the public at large.

The circumstances defined within the stakeholder process may, for example, include limits on the magnitude of the Firm Demand interrupted, a provision that the planned interruption of Firm Demand may only be utilized for a specific number of years (temporary), or the number of hours per year where Firm Demand could be limited. With the wide variety of circumstances across North America, the stakeholder processes may also include other parameters.

The stakeholder processes would also define how alternatives are evaluated. Typically, alternatives are evaluated based on a wide range of factors, including probability of the event, the load shape, the number of hours per year of exposure, initial cost, on-going costs, and may address the value of electric service to customers or other regulatory concerns. NERC's expectation is that the documentation would include the specifics of the situation, including the alternatives considered and the evaluation that was conducted to select the alternative to interrupt Firm Demand for a Category 'b' contingency as a means of resolving a planning issue.

The ERO Compliance Enforcement Authority (CEA)[9] will verify that any planned interruptions of Firm Demand utilizing Footnote b that were included in the planning assessment to address

[9] The CEA is defined in the NERC Rules of Procedure at Section 1.1.7 as: "NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards." "Compliance Monitoring and Enforcement" also appears throughout the FERC-approved Regional Delegation Agreements and the FERC-approved separate agreements between NERC and SERC, FRCC, and SPP. NPCC's agreement with WECC will also address the compliance monitoring and enforcement activities.

Bulk Electric System performance requirements were conducted pursuant to circumstances that were vetted through the stakeholder process and been documented as acceptable instances. To evaluate whether the circumstances constitute an acceptable instance for planned interruptions, the ERO will verify that the stakeholder process included consideration of alternatives and, given the alternatives, the stakeholder process resulted in determining that the circumstance was an acceptable instance. Additionally, the ERO CEA will determine the sufficiency of the documentation provided, including the documentation of alternatives considered and adherence to the stakeholder process.

Specifically if a planned interruption was qualified as "Firm Demand that needed to be interrupted to address Bulk Electric System performance requirements" utilizing Footnote b, the CEA will review the stakeholder process to verify that the process fulfilled the intent of the standard. An auditor will request:

1. Identification of the Authority(ies) Having Jurisdiction (AHJ)[10] and the applicable stakeholder process that applies to the registered entity and the geographic region under consideration for the transmission planning investment. This process will be one that is mandated by another regulating body having jurisdiction; if the entity is subject to jurisdiction by more than one regulating body and more than one of those regulating bodies required a stakeholder process, the registered entity must identify which stakeholder process it elected to use for compliance with the NERC standard;
2. The registered entity's documented basis for identifying the applicable process for stakeholder review of planning decisions and potential interruptions of Firm Demand to address Bulk Electric System performance requirements, including whether it had selected from several qualifying stakeholder processes, and whether it had identified the regulating or governmental body requiring the process;
3. To evaluate whether the circumstances constituted an acceptable instance in utilizing planned interruptions, the ERO will verify that the stakeholder process included consideration of alternatives and, given the alternatives, the stakeholder process determined the circumstance was an acceptable instance and had been documented as such;
4. To validate the process, evidence of how the process fulfills the requirements of Footnote b that: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities;
5. Evidence that the registered entity has trained its planning staff on the process and that the planning staff has access to the process;
6. Evidence that the registered entity has either implemented the process or, if the process has not been implemented, evidence that the training staff is aware of when the process must be implemented and how to implement it;

[10] This could also include state public utility commissions.

7. Evidence that the planned Firm Demand Interruption is not expected to exceed the magnitude, duration, voltage level, and location of the planned Firm Demand interruptions that were determined to be acceptable in the stakeholder process; and
8. If the registered entity has implemented the process, evidence that the process was followed. This may include contacting the affected parties to verify they received or have access to the stakeholder decisions.

Question 4:

Please explain and quantify the extent to which Firm Demand is planned to be interrupted pursuant to the currently-effective footnote 'b' of TPL-002-0a. Provide itemized estimates, for each Regional Entity (RE), for each entity that interrupts Firm Demand, including the magnitude, duration, voltage level, and location of the Firm Demand planned interruptions. Please explain and quantify how many exceptions the ERO expects in conjunction with its revisions to proposed footnote 'b.'

NERC Response to 4(a):

Question 4(a): Please explain and quantify the extent to which Firm Demand is planned to be interrupted pursuant to the currently-effective footnote 'b' of TPL-002-0a.

NERC and the Regional Entities have not collected statistics or preformed a survey concerning the prospective implementation of Footnote b under TPL-002-0a. During the drafting team's deliberations concerning TPL-001-2 and TPL-002-0a Footnote b, including the NERC Technical Conference on Footnote b, the informal assessments demonstrated that the use of Footnote b would not be widespread. Certain examples of load areas where the system was understandably limited by geography, such as the Florida Keys and Cape Cod, were identified

The expectation is that the number of exceptions with the revised Footnote b will be no more than with the existing Footnote b and the number could be reduced when each use of the exception goes through the open, transparent stakeholder process. This transparency will allow regulators and all stakeholders to participate in the review of these situations.

NERC Response to 4(b):

Question 4(b): Provide itemized estimates, for each Regional Entity (RE), for each entity that interrupts Firm Demand, including the magnitude, duration, voltage level, and location of the Firm Demand planned interruptions. Please explain and quantify how many exceptions the ERO expects in conjunction with its revisions to proposed footnote 'b.'

NERC does not have itemized estimates of planned interruptions permitted under Footnote b. NERC does have information on Firm Demand that was shed through the Energy Emergency Alerts Process. The statistics and each event can be found on the NERC reliability indicators page at: http://www.nerc.com/page.php?cid=4|331. *See*, the EEA2 and EEA3 portions of this page. The EEA3 events, where firm load interruptions were a factor, are posted at: http://www.nerc.com/page.php?cid=5|65. While not all Energy Emergency Alerts are a result of transmission planning choices, this source of data could be reviewed to determine if it was useful for spot checks.

The revised Footnote b states:

> *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 address BES performance requirements.

For instances where planned Firm Demand interruptions were utilized in the planning process, auditors will be requiring evidence that each planned interruption was qualified under one of the three provided situations in Footnote b and was performed in accordance with the documented methodology/process/operational guide dictating the manner in which each specific planned interruption was to take place. Therefore, auditors will be evaluating magnitude, duration, voltage level and location of each planned Firm Demand interruption to ensure that the planned interruption is qualified under one of the situations identified in Footnote b.

Specifically if a planned interruption was qualified as "Firm Demand that needed to be interrupted to address Bulk Electric System performance requirements" utilizing Footnote b, the CEA will review the stakeholder process to verify that the process fulfilled the intent of the standard. An auditor will request:

1. Identification of the Authority(ies) Having Jurisdiction (AHJ)[11] and the applicable stakeholder process that applies to the registered entity and the geographic region under consideration for the transmission planning investment. This process will be one that is mandated by another regulating body having jurisdiction; if the entity is subject to jurisdiction by more than one regulating body and more than one of those regulating bodies required a stakeholder process, the registered entity must identify which stakeholder process it elected to use for compliance with the NERC standard;
2. The registered entity's documented basis for identifying the applicable process for stakeholder review of planning decisions and potential interruptions of Firm Demand to address Bulk Electric System performance requirements, including whether it had selected from several qualifying stakeholder processes, and whether it had identified the regulating or governmental body requiring the process;
3. To evaluate whether the circumstances constituted an acceptable instance in utilizing planned interruptions, the ERO will verify that the stakeholder process included consideration of alternatives and, given the alternatives, the stakeholder process determined the circumstance was an acceptable instance and had been documented as such;
4. To validate the process, evidence of how the process fulfills the requirements of Footnote b that: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities;
5. Evidence that the registered entity has trained its planning staff on the process and that the planning staff has access to the process;

[11] This could also include state public utility commissions.

6. Evidence that the registered entity has either implemented the process or, if the process has not been implemented, evidence that the training staff is aware of when the process must be implemented and how to implement it;
7. Evidence that the planned Firm Demand Interruption is not expected to exceed the magnitude, duration, voltage level, and location of the planned Firm Demand interruptions that were determined to be acceptable in the stakeholder process; and
8. If the registered entity has implemented the process, evidence that the process was followed. This may include contacting the affected parties to verify they received or have access to the stakeholder decisions.

Question 5:

Please explain in detail the stakeholder process, including why a stakeholder process is necessary or desirable. In your response, please address each of the following: (1) who conducts and participates in the stakeholder process and their roles; (2) whether the ERO and REs have review and approval responsibilities in the stakeholder process and what those responsibilities are; if they do not have responsibilities, please explain why and how is the process otherwise validated; and (3) how the stakeholder process decisions (allowing in some circumstances interruption of Firm Demand for a single contingency) would be made available to appropriate reliability entities (e.g., planning authorities, REs, reliability coordinators, etc.) for their analysis and subsequent studies.

NERC Response to Question 5(1):
(Who conducts and participates in the stakeholder process and their roles):
There are numerous stakeholder processes where transmission issues are vetted and choices regarding reinforcement are developed. These include many pre-existing Order No. 890 planning processes created by various groups of transmission-owning entities to fulfill the requirements of Order No. 890.

Through Order No. 890, FERC has extensive experience at creating and managing nationwide stakeholder processes. Order No. 890 already mandates that processes with the following requirements, which are either directly or indirectly applicable to the transmission planning process, be met through the stakeholder processes. Some of these requirements are:

- Transmission Providers must post a "strawman" proposal for compliance with each of the ***nine planning principles***[12] adopted in the Final Rule.[13] This may be posted on the Transmission Providers website or its OASIS site (P 443);

[12] Emphasis added (bold, italics) to those Order No. 890 requirements that are non-rate terms related to transmission planning.
[13] These nine planning principles are: (1) Coordination – transmission providers must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis; (2) Openness – transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers and state authorities); (3) Transparency – transmission providers are required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans; (4) Information Exchange – network transmission customers are required to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load; (5) Comparability – after considering the data and comments supplied by market participants, each transmission provider develop a transmission system plan that (a) meets the specific service requests of its transmission customers and (b) otherwise treats similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning; (6) Dispute Resolution – transmission providers must propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third party neutral; (7) Regional Participation – each transmission provider is required to coordinate with interconnected systems to (a) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (b) identify system enhancements that could relieve congestion or integrate new resources; (8) Economic Planning Studies – the transmission planning process under the pro forma OATT must consider both reliability and economic considerations. The purpose of this principle is to ensure that the latter is considered adequately in the transmission planning process; (9) Cost Allocation for New Projects – Planning processes must address the allocation of costs of new facilities (i.e.

- Transmission providers that have not been approved as ISOs or RTOs, and whose transmission facilities are not under the control of an ISO or RTO, must submit FPA section 206 filings that contain the ***non-rate terms*** and conditions set forth Order No. 890. These filings need only contain the revised provisions adopted in Order No. 890. Transmission providers utilizing the optional implementation FPA section 205 filing described above, need only submit tariff sheets necessary to implement the remaining modifications required under the Order No. 890, *i.e.*, modifications related to tariff provisions that did not implicate previously-approved variations (P 135);

- Each transmission provider is directed to post a draft of the attachment to its OATT governing ***transmission planning*** on its OASIS, or on its website if it does not have an OASIS (*see, Order Extending Compliance Action Date and Establishing Technical Conferences*);

- ISOs and RTOs, and transmission providers located within an ISO/RTO footprint, submit FPA section 206 filings that contain the ***non-rate terms*** and conditions set forth in the Final Rule. These filings need only contain the revised provisions adopted in the Final Rule or a demonstration that previously approved variations continue to be consistent with or superior to the revised *pro forma* OATT (PP 157, 161);

- Submit compliance filings with Attachment K (Planning) of the *pro forma* OATT or RTOs and ISOs file a demonstration that their ***planning processes*** are consistent with or superior to the planning principles in the Final Rule (*see,* PP 140, 422, and *Order Extending Compliance Action Date and Establishing Technical Conferences*);

- N/A Transmission Providers must file a revised Attachment C to incorporate any changes to ***NERC's*** and NAESB's reliability and business practice standards to achieve consistency in ATC within 60 days of completion of the NERC and NAESB processes (P 325); and

- After the submission of FPA section 206 compliance filings, transmission providers may submit FPA section 205 filings proposing rates for the services provided for in the tariff, as well as ***non-rate terms and conditions*** that differ from those set forth in the Final Rule if those provisions are "consistent with or superior to" the *pro forma* OATT (P 135).

Other key planning forums where decisions regarding planning for transmission service include: Eastern Interconnection Planning Collaborative ("EIPC") which is the collective effort of Planning Authorities, requiring input from stakeholders, including state commissions, in the Eastern Interconnection to perform a coordinated transmission expansion study looking at several possible futures over a twenty year planning horizon.

Transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs).

Other coordinated transmission expansion efforts are underway in the Electric Reliability Council of Texas ("ERCOT") through the Long Term System Assessment done in conjunction with the Electric System Constraints and Needs study and in the Western Interconnection with Western Electricity Coordinating Council's ("WECC") efforts to develop a 10-year and 20-year transmission expansion plan. The recommendations from this planning process typically are inserted into siting determination or environmental compatibility determination processes by an applicant. Whether it is an Order No. 890 specific process or not, the specific process to use depends on the entity planning to construct the project, the authority having jurisdiction (AHJ) over the entity, and the geographical region (*e.g.*, a state regulatory commission over an investor owned utility). In some instances, such as a Federal Power Marketing Agency, the Agency itself will manage the siting review and economic choice process.

NERC Response to Question 5(2):

(Whether the ERO and REs have review and approval responsibilities in the stakeholder process and what those responsibilities are; if they do not have responsibilities, please explain why and how is the process otherwise validated):

NERC and Regional Entities are generally not a party to the proceedings, nor do they have a review role of the plans except in a few instances as cited above within WECC and ERCOT. However, NERC and the Regional Entities will evaluate the outcomes in the entities' planning assessment through the NERC audit process. In various planning forums, even in Eastern Interconnection RTOs, the entity that coordinates the planning may not have the authority to site and make economic choices regarding new transmission facilities. Each stakeholder process must recognize these varied planning and siting issues and must be developed around the rules and regulations that apply to that stakeholder process. In addition, an entity's transmission plans must ultimately meet NERC Reliability Standards and provide non-discriminatory transmission access under OATT requirements.

NERC Response to Question 5(3):

(How the stakeholder process decisions (allowing in some circumstances interruption of Firm Demand for a single contingency) would be made available to appropriate reliability entities (e.g., planning authorities, REs, reliability coordinators, etc.) for their analysis and subsequent studies):

These pre-existing processes are open to interested stakeholders. Decisions may be available in a public docket, but are not explicitly made available to the ERO. The only way to achieve that would be for NERC to become a party to each siting or environmental case in North America. While it is not possible to determine in advance which processes might involve the decision to implement Footnote b, NERC would have to intervene in all of these cases in order to obtain the applicable information. Accordingly, a better approach is to make visible each use of Footnote b by the Planning Entity and then use the compliance program to generate reports on Footnote b's use. Importantly, the proposed Footnote b makes this issue and planning choices publicly visible for the first time, on a common platform.

The ERO will monitor the stakeholder process much in the same manner as the current PRC-005 Maintenance and Testing Program is currently monitored. That is, the onus is on the registered entity to provide the CEA or auditor with its mandated stakeholder review process, as required by another regulating body's regulations, and evidence that it is following its process. An auditor will request:

1. Identification of the Authority(ies) Having Jurisdiction (AHJ)[14] and the applicable stakeholder process that applies to the registered entity and the geographic region under consideration for the transmission planning investment. This process will be one that is mandated by another regulating body having jurisdiction; if the entity is subject to jurisdiction by more than one regulating body and more than one of those regulating bodies required a stakeholder process, the registered entity must identify which stakeholder process it elected to use for compliance with the NERC standard;
2. The registered entity's documented basis for identifying the applicable process for stakeholder review of planning decisions and potential interruptions of Firm Demand to address Bulk Electric System performance requirements, including whether it had selected from several qualifying stakeholder processes, and whether it had identified the regulating or governmental body requiring the process;
3. To evaluate whether the circumstances constituted an acceptable instance in utilizing planned interruptions, the ERO will verify that the stakeholder process included consideration of alternatives and, given the alternatives, the stakeholder process determined the circumstance was an acceptable instance and had been documented as such;
4. To validate the process, evidence of how the process fulfills the requirements of Footnote b that: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities;
5. Evidence that the registered entity has trained its planning staff on the process and that the planning staff has access to the process;
6. Evidence that the registered entity has either implemented the process or, if the process has not been implemented, evidence that the training staff is aware of when the process must be implemented and how to implement it;
7. Evidence that the planned Firm Demand Interruption is not expected to exceed the magnitude, duration, voltage level, and location of the planned Firm Demand interruptions that were determined to be acceptable in the stakeholder process; and
8. If the registered entity has implemented the process, evidence that the process was followed. This may include contacting the affected parties to verify they received or have access to the stakeholder decisions.

[14] This could also include state public utility commissions.

Question 6 Response:

Please explain whether and to what extent the planning entity proposing to be allowed loss of Firm Demand for a single contingency conducts the stakeholder process, or is involved in deciding the merits of a request for exception. In your response, please explain whether a planning entity would make a self determination, a joint-determination, or an abstention from the decision concerning its requested exception.

The planning entity does not generally control the stakeholder process, it is a party to the process unless it is a federal Power Marketing Agency, or other similar government entity not subject to state regulatory jurisdiction. The planning entity (particularly if it is an investor owned utility) is usually, but not always, a participant. In general, there are other planning processes conducted under FERC Order No. 890 (and related successor orders) which may apply to transmission planning decisions. The issue of cost is also considered in the various Order No. 890 processes.

A few examples of processes covering specific regions of the country are:

- In South Carolina, the South Carolina Regional Transmission Planning Process (SCRTPP) was created to address transmission planning and make the process open to stakeholders. Information on this process is available at: http://www.scrtp.com/en/ IP. The process was established jointly by the South Carolina Electric & Gas Company (SCE&G) and the South Carolina Public Service Authority (Santee Cooper) to meet the transmission planning requirements of FERC Order Nos. 890, 890-A and 890-B.

- The Southeast Inter-regional Participation Process (SIRPP), with information available at: http://www.southeastirpp.com/. This inter-regional process complements the regional planning processes developed by the Participating Transmission Owners in the Southeast. The SIRPP was created to more fully address the regional participation principle of Order No. 890 for multiple transmission systems in the Southeast.

- The New York ISO process, with information available at: http://www.nyiso.com/public/webdocs/services/planning/NYISO_Posting_for_FERC_Order_890_091407_final.pdf.

- The California ISO process, with information available at: http://www.caiso.com/1bda/1bdab40d5960.html.

The ERO CEA will verify that the registered entity only included planned Firm Demand interruptions to address Bulk Electric System performance requirements for circumstances that have been approved through the stakeholder process. To validate the process, the ERO CEA will require evidence of how the process fulfills the requirements of Footnote b: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities.

Question 7 Response:

Please explain the technical justification and criteria a planning entity would be required to provide in support of its exception request. Please explain the objective criteria the stakeholder process would employ to make decisions on requested exceptions.

Footnote B does not envision an exception request. As described in detail above, the stakeholder processes that could apply are not under the control of NERC.

The ERO CEA or auditor will verify that the registered entity only included planned Firm Demand interruptions to address Bulk Electric System performance requirements for circumstances that have been approved through the stakeholder process.

Question 8 Response:

Please identify who would make the final decision to allow an entity to plan to interrupt Firm Demand for a single contingency in the stakeholder process. Please explain whether there would be processes or safeguards the ERO and RE would employ to ensure objectivity, consistency, and integrity of stakeholder process exceptions and what these safeguards would be. Please explain whether and how the list of exceptions would be made available (e.g., by RE, planning entity, or other) and who would be responsible for maintaining the list.

The planning entity will be responsible for executing a plan that has been vetted through the stakeholder process. NERC has no role in the stakeholder process design.

The authority with jurisdiction over that planning entity would be responsible for the approval of those decisions based on processes already in place (*see*, examples provided in previous answers). These processes are in the jurisdiction of various states or other agencies (*e.g.*, power marketing agencies), pursuant to Order No. 890 and other regulatory orders (state or federal), and NERC does not have the authority to direct or redirect the design of these processes, particularly those processes that apply to entities that are not users, owners, or operators of the bulk power system.

The NERC ERO CEA or auditor will verify that the registered entity only included planned Firm Demand interruptions to address bulk power system performance requirements for circumstances that have been approved through the stakeholder process. To validate this process, the ERO CEA or auditor will require evidence of how the process fulfills the requirements of Footnote b: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities.

Question 9 Response:

Proposed footnote ‘b’ contemplates “a stakeholder process that includes addressing stakeholder comments.” If the decision whether to allow the planned interruption of Firm Demand for a single contingency is denied, please explain whether there are appeal rights of the denied planning entity. Please explain any appeal rights of the party(ies) affected by the planned interruption of Firm Demand in the stakeholder process. Please explain whether and how the ERO and RE would ensure those appeal rights.

Stakeholder processes employed under Order No. 890 and by various state commissions typically are open and inclusive. NERC’s compliance verification of the use of those processes would look for evidence of those attributes. For example, Order No. 890 requires Transmission Providers to post a “strawman” proposal for compliance with each of the nine planning principles adopted in the Final Rule. Three of these principles require that Transmission Providers: 1) use openness in transmission planning meetings, allowing all affected parties to participate; 2) use transparency and disclose to all customers and other customers the basic criteria, assumptions, and data that underlie their transmission system plans; and (3) provide a dispute resolution service, whereby transmission providers must propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third party neutral.

The ERO will monitor the stakeholder process much in the same manner as the current PRC-005 Maintenance and Testing Program is currently monitored. That is, the onus is on the registered entity to provide the CEA with its mandated stakeholder review process, as required by another regulating body’s regulations, and evidence that it is following its process. An auditor will request:

1. Identification of the Authority(ies) Having Jurisdiction (AHJ)[15] and the applicable stakeholder process that applies to the registered entity and the geographic region under consideration for the transmission planning investment. This process will be one that is mandated by another regulating body having jurisdiction; if the entity is subject to jurisdiction by more than one regulating body and more than one of those regulating bodies required a stakeholder process, the registered entity must identify which stakeholder process it elected to use for compliance with the NERC standard;
2. The registered entity’s documented basis for identifying the applicable process for stakeholder review of planning decisions and potential interruptions of Firm Demand to address Bulk Electric System performance requirements, including whether it had selected from several qualifying stakeholder processes, and whether it had identified the regulating or governmental body requiring the process;
3. To evaluate whether the circumstances constituted an acceptable instance in utilizing planned interruptions, the ERO will verify that the stakeholder process included consideration of alternatives and, given the alternatives, the stakeholder process

[15] This could also include state public utility commissions.

determined the circumstance was an acceptable instance and had been documented as such;

4. To validate the process, evidence of how the process fulfills the requirements of Footnote b that: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities;
5. Evidence that the registered entity has trained its planning staff on the process and that the planning staff has access to the process;
6. Evidence that the registered entity has either implemented the process or, if the process has not been implemented, evidence that the training staff is aware of when the process must be implemented and how to implement it;
7. Evidence that the planned Firm Demand Interruption is not expected to exceed the magnitude, duration, voltage level, and location of the planned Firm Demand interruptions that were determined to be acceptable in the stakeholder process; and
8. If the registered entity has implemented the process, evidence that the process was followed. This may include contacting the affected parties to verify they received or have access to the stakeholder decisions.

Question 10 Response:

Please explain whether and how the ERO and RE would review decisions to allow planned interruptions of Firm Demand for a single contingency stemming from the stakeholder process. Please explain whether and how the ERO and RE would periodically re-evaluate the continued validity of prior exceptions decisions as part of the corrective plans to meet bulk electric system performance requirements.

The ERO and Regional Entities will not review decisions regarding planned interruptions. The ERO and Regional Entity's role is limited to reviewing whether the registered entity participated in a stakeholder process when interrupting Firm Demand for planning issues. It would be inappropriate for the ERO and Regional Entities to be involved in the planning process while they are responsible for monitoring compliance and conducting enforcement activities, if necessary.

NERC will, through its compliance program, identify first whether Footnote b was employed by the planning entity. If the answer is "yes", NERC will then proceed to test whether the attributes called for in Footnote b were met.

The ERO CEA will verify that the registered entity only included planned Firm Demand interruptions to address Bulk Electric System performance requirements for circumstances that have been approved through the stakeholder process. To validate the process, the ERO will monitor the stakeholder process much in the same manner as the current PRC-005 Maintenance and Testing Program is currently monitored; the onus is on the registered entity to provide the CEA or auditor with its mandated stakeholder review process, as required by another regulating body's regulations, and evidence that it is following its process.

An auditor will request:

1. Identification of the Authority(ies) Having Jurisdiction (AHJ)[16] and the applicable stakeholder process that applies to the registered entity and the geographic region under consideration for the transmission planning investment. This process will be one that is mandated by another regulating body having jurisdiction; if the entity is subject to jurisdiction by more than one regulating body and more than one of those regulating bodies required a stakeholder process, the registered entity must identify which stakeholder process it elected to use for compliance with the NERC standard;
2. The registered entity's documented basis for identifying the applicable process for stakeholder review of planning decisions and potential interruptions of Firm Demand to address Bulk Electric System performance requirements, including whether it had selected from several qualifying stakeholder processes, and whether it had identified the regulating or governmental body requiring the process;
3. To evaluate whether the circumstances constituted an acceptable instance in utilizing planned interruptions, the ERO will verify that the stakeholder process included consideration of alternatives and, given the alternatives, the stakeholder process

[16] This could also include state public utility commissions.

determined the circumstance was an acceptable instance and had been documented as such;

4. To validate the process, evidence of how the process fulfills the requirements of Footnote b that: 1) the use of planned Firm Demand interruption for a single contingency is reviewed in an open and transparent stakeholder process that includes addressing stakeholder comments; and 2) the stakeholder process decisions allowing planned interruption of Firm Demand for a single contingency are communicated to or made available to appropriate reliability entities;
5. Evidence that the registered entity has trained its planning staff on the process and that the planning staff has access to the process;
6. Evidence that the registered entity has either implemented the process or, if the process has not been implemented, evidence that the training staff is aware of when the process must be implemented and how to implement it;
7. Evidence that the planned Firm Demand Interruption is not expected to exceed the magnitude, duration, voltage level, and location of the planned Firm Demand interruptions that were determined to be acceptable in the stakeholder process; and
8. If the registered entity has implemented the process, evidence that the process was followed. This may include contacting the affected parties to verify they received or have access to the stakeholder decisions.

Question 11:

On page 10 of your filing, you state the Commission's instructions to clarify "footnote 'b' in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss..." have been addressed. Please explain in detail, and provide the development record for, how the ERO determined the magnitude and duration of consequential load loss that would be allowed.

NERC Response to Question 11:

In Paragraph 1795 of Order No 693, the Commission stated:

> The Commission, therefore, **suggests that the ERO consider developing a ceiling** (emphasis added) on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process. Further, we note that the DOE thresholds for reporting disturbances on Form EIA-417 would be one example of an appropriate starting point for developing such a ceiling. These thresholds for load loss are 300 MW for 15 minutes or 50,000 customers for one hour, whichever is greater.

During the standards development process for TPL-001-2, the amount and duration of consequential load loss was thoroughly vetted. Starting with Draft 1 of the revised standard, a requirement was included that the planner would need to document the maximum amount and duration of Consequential Load loss. This approach was chosen as a method to develop a record of the various amounts or criteria that are utilized across North America. There was much concern raised about this approach. The issues addressed during the comment period were that the acceptable amount of Consequential Load loss was a states' rights issue, that this load loss was not a Bulk Electric System reliability issue, and that the reporting of the maximum amount of load was an administrative requirement that does not improve Bulk Electric System reliability. The reporting of the maximum amount of Consequential Load Loss was deleted before Draft 5 of the proposed footnote was posted on January 6, 2010. Therefore, the NERC Reliability Standard focused on the acceptable circumstances for use of Footnote b rather than on the amount of load.

Under Section 215 of the Federal Power Act, NERC cannot compel registered entities to build, and specifying a bright-line number of megawatts would imply a service quality other than radial service which would, in effect, be compelling entities to build.

<u>Citations to March 31, 2011 Development Record</u>
June 10, 2010 Consideration of Comments: pp. 10, 12, 13, 14, 15, 20, 22, 23, 25, 26, 27, 28, 29, 30, 31-33, 38, 41, 43, 44, 45, 47, 49, 50

August 30, 2010 Consideration of Comments: pp. 12, 13, 15, 16, 17, 18, 24, 26, 27, 28, 32, 33, 34, 36, 37, 38, 39, 43, 47, 48, 49, 50, 51, 52, 54, 56, 57

October 27, 2010 Consideration of Comments: pp. 18, 19, 22, 23, 24, 26

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 7th day of June, 2011.

<u>/s/ Holly A. Hawkins</u>
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation