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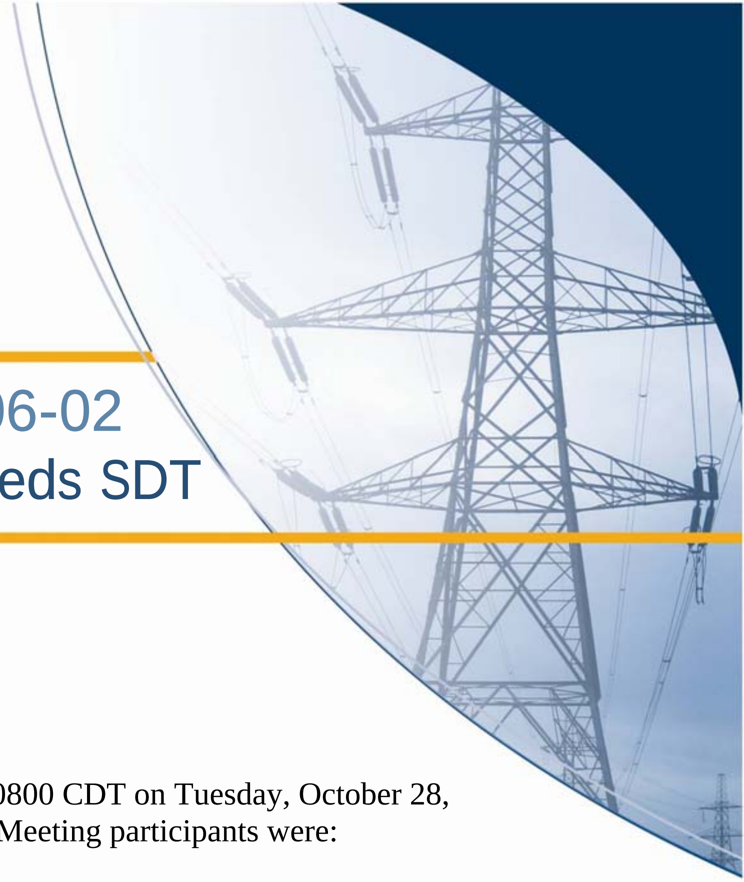

# Meeting Notes for Project 2006-02
# Assess Transmission Future Needs SDT

**October 28–29, 2008**
LCRA Offices
Austin, TX

## 1. Administrative Items

**a.** Introductions and Quorum
The Chair brought the meeting to order at 0800 CDT on Tuesday, October 28, 2008 at the LCRA Offices in Austin, TX. Meeting participants were:

| | | |
|---|---|---|
| Darrin Church | Bill Harm | Julius Horvath |
| Bob Jones | Brian Keel | Ron Mazur |
| Bob Millard, Vice Chair | John Odom, Chair | Bernie Pasternack |
| Bob Pierce | Chifong Thomas | Jim Useldinger |
| Dana Walters | Ray Kershaw, Observer | Charles Long, Observer |
| Steve Rueckert, Observer | Hari Singh, Observer | Curt Stepanek, Observer |
| Yury Tsimberg, Observer | Guy Zito, Observer | Ed Dobrowolski, NERC |
| Tom Gentile, Observer | | |

**b.** NERC Antitrust Compliance Guidelines — Ed Dobrowolski
There were no questions raised on the NERC Antitrust Compliance Guidelines.

**c.** Agenda and Objectives — John Odom
The goal of this meeting is to attempt to finalize the responses to industry comments. Other topics will be addressed as time permits.

## 2. Guidelines for Breakout Sessions — John Odom

Sub-teams need to defend SDT positions if it appears that the industry misunderstands what the standard says. Any changes to the standard must be based on sound technical judgments and not just a knee-jerk reaction to a few negative comments. The SDT wants to promote a standard that the industry will support and vote for but there are many entities that may not have responded since they agreed with the SDT position.

## 3. Sub-team Breakout Sessions

Sub-teams worked on finalizing responses, identifying items requiring full team discussion, and identifying proposed changes to requirements.

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## 4. Reports from Sub-team Leaders

### a. Team A — Bernie Pasternack

This sub-team was responsible for questions 1, 2, 4, and 6.

**Question 1 Summary —** By a significant majority (about two-thirds), the industry did not agree with the two definitions, as modified in the latest draft. Most of those disagreeing still express a fundamental disagreement with the approach of separating plant stability from system stability. Essentially many argue that plant stability is simply a subset of system stability, and the standard requirements could be simplified by focusing on stability performance in a generic way. In this way stability performance could be viewed in the context of individual units (generating unit stability) or groups of units (system stability). Some of these same commenters also argue that generating unit stability is already covered by FAC-001 and FAC-002 and, therefore, should be dropped from the TPL-001-1 standard; otherwise double jeopardy could attach. Many of these same commenters also suggested that if separation of generating unit stability is retained in the final draft, then certain refinements of the requirements language should be made.

Others who voted No, as well as some who generally support the language of the current draft recommended a variety of changes to the definitions and requirements for further clarity.

Only some 20+ percent of the commenters supported the current draft definitions without reservation**.**

**Question 1 Recommendation —** Team A recommends that the SDT eliminate the distinction between generating unit stability and system stability, which many industry commenters believe is an artificial distinction. A quick review of comments on Q15 indicates only 11 who definitely support the current draft as a whole, a much larger number who do not, and a substantial number who are unsure. Without looking at the detailed comments, one can't say how much more support could be gained by making the changes suggested by the industry relative to Q1, but it is probably safe to say that such changes would only tend to increase industry support. Team A believes that this change will not impact reliability in any negative way and would not preclude individual TPs or PCs from structuring their studies in a way that separates generating unit stability from plant stability if they chose to do so.

This recommended change would need to be coordinated with changes to the requirements language (see Q2). Should the SDT support this recommendation, the following paragraph would be added to the "Summary Consideration" and would guide the development of specific responses to each commenter: "The SDT agrees with the industry's majority view that generating unit stability and system stability need not and should not be treated as distinct issues. Consequently, the two new stability terms have been removed from the third draft, and this revised draft references the already approved term “Stability.” Furthermore, as indicated by the SDT’s response to commenters, the stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and system stability.”

**Question 1 Resolution** — The SDT endorsed the sub-team recommendation with the caveat that the suggested changes to the roadmap will be reviewed by the sub-team in light of the discussions at this meeting.

**Question 2 Summary** — A large number of responding entities expressed concern in one way or another over R2.4.1, dynamic load modeling. The expectation for meeting this requirement needs to be clarified and a longer implementation time is needed to allow utilities more time to determine a reasonable method of modeling the induction motors at an aggregate level.

A significant number of responding entities felt there was no need to state why a particular sensitivity was not studied and that the Requirements should only ask for documentation of why a particular sensitivity was chosen to be evaluated. Also, listing the sensitivities as individual sub-requirements puts too much emphasis on them. It was suggested that the sensitivities be put in a list at the end of R2.4.3 and not have sub-requirements. The sensitivity in R2.4.4 should be treated the same way and R2.4.4 should be eliminated.

Also, the industry commented that these sub-requirements are too prescriptive and that the standard should allow the Planner to use his judgment in determining the sensitivities to study.

Also, some clarification language is needed to better define some of the terms in this list, i.e., variability of reactive resources, modification of expected transfers, other dispatch scenarios, etc.

A large number of responding entities expressed concerns regarding generating unit stability requirements conflicting with FAC standards. These concerns will be taken care of if system stability and generating unit stability are combined.

A few entities pointed out that R5 requires that "known planned and long term outages of Transmission or generation equipment" be included for stability studies. However, there is no similar requirement for steady state studies.

A large number of responding entities expressed the concern that system stability studies should not be required for smaller entities.

**Question 2 Recommendation** — Team A recommends that R2.4.1 be further clarified and that the implementation period for this requirement be longer than that of any other requirement — at least 36 months. Also, more direction or education needs to come from NERC to assist the TPs and PCs in performing these studies.

Team A recommends that R2.4.3.1, R2.4.3.2, R2.4.3.3, R2.4.3.4, R2.4.3.5, and R2.4.4 be eliminated and replaced with a list of these items at the end of R2.4.3. Team A further recommends that R2.4.3 be modified to require only the rationale for why a sensitivity was selected, not the rationale for why each sensitivity was not selected. Team A also recommends further clarification of the meaning of the sensitivities that are suggested.

Team A recommends that system stability studies continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, Team A believes it would be difficult to establish criteria for exempting "smaller entities."

Team A recommends that the requirement to include "known planned and long term outages of Transmission or generation equipment" be added somewhere in R3 for steady state studies.

**Question 2 Resolution —** Resolution was not reached on clarifying R2.4.1 during the meeting. This issue will be resolved through e-mail and conference call prior to the next meeting. The implementation time issue will be taken up when the revised Implementation Plan is discussed. The revised R2.4.1 is shown below:

R2.4.1 — System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate load model at each load bus which represents the overall dynamic behavior of loads is acceptable.

It was pointed out that bulleted lists are not permitted in a standard.

The SDT did agree that stability studies are required for all entities as recommended by the sub-team.

Any changes to the sensitivity requirements wording must be double-checked by Team D which has the responsibility for the actual sensitivity questions.

**Action Item —** Team D will double check the proposed changes to the sensitivity requirements suggested by Team A prior to the next meeting.

The additional language suggested for R3 will be taken care of with the proposed changes to R1 suggested by Team C in their response to question 5.

**Question 4 Summary —** By a nearly unanimous response, the industry agrees with the modification to Requirement R3.5 in the latest draft that allows manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. However, in response to the question, only 20+ percent of the commenters supported the current modification including the conditions in Requirements R3.5.1, R3.5.2, and R3.5.3 without reservation.

While nearly 50 percent of the commenters that agreed with the question and 25+ percent of commenters that disagreed with the question that generation run-back and tripping (manual and automatic) should be limited by the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3, all 75 percent of these commenters suggested a variety of changes, additions and clarifications to these conditions. A number of commenters expressed a fundamental disagreement that these conditions are applicable to the overall TPL standard and that their specific listing in R3.5 gives the impression that these conditions are only applicable to R3.5 and not to the other Requirements in this Standard. It was also pointed out that some of these conditions are already covered elsewhere in the standard or listed as numbered items at the beginning of the tables, and therefore should be dropped as specific requirements in the TPL-001-1 standard. One commenter stated that Requirement R3.5 is not a requirement, but an allowed action to meet the performance requirements.

**Question 4 Recommendation —** Based on a strong majority of industry responses, Team A recommends that the SDT eliminate Requirement R3.5 and its conditions listed in Requirements R3.5.1, R3.5.2, and R3.5.3 related to manual and automatic generation run-back and tripping as a response to a single or multiple Contingency as well as the similar Requirement R5.4.3 and its conditions listed in Requirements R5.4.3.1, R5.4.3.2, and R5.4.3.3 related to automatic generation tripping to mitigate Stability violations.

Team A believes that the existing language in Requirement R2.7.1 listing the actions needed to achieve required System performance can be modified to include the use of manual or automatic generation run-back or tripping as a response to a single or multiple Contingency and automatic generation run-back or tripping to mitigate Stability violations.

Team A believes that conditions R3.5.1 and R3.5.3, R5.4.3.1, and R5.4.3.3 are already covered in the TPL-001-1 Standard as numbered items at the beginning of the Tables. The need to keep the condition listed in R3.5.2 and R5.4.3.2 regarding such action not violating safety, equipment, regulatory or statutory requirements should be reconsidered as it may already be covered in other standards or at the very least be clarified and added to the list of numbered items at the beginning of the Tables.

**Question 4 Resolution —** While the SDT seemed to be in general agreement with this approach, resolution was not reached on the proposed changes during the meeting. This issue will be resolved through e-mail and conference call prior to the next meeting.

**Question 6 Summary —** There were 31 no votes, 14 yes and no votes, and 15 yes votes, indicating an overall negative vote.

In general, commenters indicated a need for clarifying what specific short-circuit studies were required. While it's an annual requirement, what year or years should be studied? Is there both a short-term and long-term requirement or is it just short-term? In addition, the need for studies beyond those of a "normal system" was also questioned. Four entities suggested these requirements belong in a separate standard such as FAC-002 or a new standard.

**Question 6 Recommendation** — Team A recommends the following changes to the requirements:

R2.3 — The short circuit analysis portion of the Planning Assessment shall be conducted annually for all years in the 5 year near-term period for which there is a material change in topology or equipment affecting fault levels. The assessment can be supported by applicable current or past studies.

R2.6.2 — "study" was changed to "network model" and now reads as follows: For steady state, short circuit, or Stability analysis: the network model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

R4 — For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment for the network model with all generation and transmission facilities affecting fault levels in service. All affected equipment including circuit breakers, bus sections (structures and supports) and ground mats shall have applicable ratings that exceed the breaker interrupting duties and equipment short circuit stresses.

[Note to the SDT: An alternative wording would limit R4 to address only circuit breaker interrupting duties.]

[Note to the SDT: The language in this requirement was also changed to reflect the removal of the distinction between Generating Plant Stability and System Stability.]

**Question 6 Resolution** — The SDT does not agree with the commenters on the assertion that FAC-002 covers this issue. FAC-002 is only for initial interconnections and thus does not cover on-going conditions.

The SDT was in general agreement with the suggested approach but resolution was not reached on the proposed changes during the meeting. This issue will be resolved through e-mail and conference call prior to the next meeting. The alternate wording for R4 seemed to be more palatable to the SDT. Use of terms such as 'applicable' is not allowed in standards.

b. **Team B — Chifong Thomas**
This team was assigned questions 3, 7, 8, 9, and 11.

**Question 3 Summary** — There is overwhelming support from the industry to allow the flexibility to interrupt local area network load and firm transfer service to provide thermal and voltage relief in response to a first contingency. The industry sees this ability to be an operating tool that is presently available in footnote b. If the industry loses the ability to interrupt pumping load, to shed local load through SPS/RAS action, and to take credit for the temporary load reduction caused by a post contingency voltage drop; then significant upgrade costs will need to be incurred. It was noted by several commentors that if this is left as it is, then it will provide a disincentive to design a reliable load serving network and will encourage a radial design that will incorporate direct dropping of load by designing it to be consequential. If this isn't changed, then it needs to be clarified that non-consequential load can be dropped after a second N-1 in an N-1-1 analysis.

It was also noted that loads that drop out due to a dynamic event should be recognized so that the modeling will predict the correct dynamic response.

There are some comments that firm transfer service is getting preferential treatment over load, which also involves the definition of firm versus conditional firm (response to Question 7).

There are some questions on the 300kV threshold, but there didn't seem to be a strong anti-sentiment except from BCTC, which indicated that they have a Network served from a radial line. They use load shedding as an adjustment to stabilize a post contingency island. If they need to provide redundancy, it would be extremely expensive.

There are significant comments on the need to separate definition from requirements and to provide additional definitions or explanation of terms, including the use of 'source', 'planning entity', 'non-interruptable load', and 'BES'.

There are some comments on whether the standard should be specific on the amount and duration of an acceptable loss of load. There are more comments requesting specific limits than those requesting removal of the reference.

First Energy raised a concern with the year one definition and a potential requirement to perform two near term planning studies (one by planning and one by operations) as being unnecessary and burdensome. First Energy and Manitoba Hydro noted that the definition for the Planning Coordinator should be in the Functional Model and it didn't belong in the TPL standard.

**Question 3 Recommendation —** The sub-team is recommending the following revised (or new) definitions:

*Consequential Load Loss:* Interruptible and Non-Interruptible Load that is no longer served by any Transmission Owner's facilities as a result of the facilities being removed from service by a planned protection system operation to isolate fault conditions.

*Non-Consequential Load Loss***:** Non-Interruptible Load loss other than Consequential Load Loss.

*Non-Interruptible Load***:** Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment.

*Ancillary Load Loss***:** Load that is disconnected from the network by customer equipment responding to measured system parameters which are deemed acceptable by the Planning Coordinator, but the system parameters are not acceptable to the load customer.

*Load Reduction***:** Load that is still connected to the system, but is reduced due to lower voltage conditions following a Planned Event.

*Load Shedding Schemes***:** Protection systems designed to remove Interruptible or Non-Interruptible load from the system in response to events which would otherwise result in unacceptable consequences to the system.

*Generation Runback or Tripping Schemes***:** Protection systems designed to runback or trip generation from the system in response to events which would otherwise result in unacceptable consequences to the system.

If the above definitions are accepted then Note 4 in table 1 should be changed as shown (Note — If these changes are accepted, then the SDT may want to pull this out of the Note section and place it somewhere more visible.):

Change from: “Consequential Load and consequential generation loss is allowed for all events shown” to: “Consequential Load Loss, Ancillary Load Loss, Load Reduction, and consequential generation loss are all allowed as a consequence of any Planning or Extreme Event defined in Tables 1 and 2, excluding P0.

Load Shedding schemes are allowed for any Planning or Extreme Event defined in Tables 1 and 2 (excluding P0), as defined or constrained by the following list:

- Under Voltage Load Shedding (UVLS) (applicable to Interruptible and Non-Interruptible load)
- Under Frequency Load Shedding (UFLS) (applicable to Interruptible and Non-Interruptible load)
- Tripping of Pumped Hydro Units
- Operator initiated emergency load shedding for conditions exceeding Planned Events (applicable to Interruptible and Non-Interruptible load)
- Special Protection Systems (SPS) or Remedial Action Schemes (RAS) that prevent unacceptable system conditions or which constrain a

disturbance from impacting the Bulk Electric System. The following are acceptable actions:

- o Shed Interruptible and Non-Interruptible load for Planned Events, as qualified in Tables 1 and 2, or Extreme Events
- o Shed load (applicable to Interruptible and Non-Interruptible load) for temporary applications for all Planned or Extreme Events, while a permanent Corrective Action Plan is developed
- o Interrupt Firm Transmission Service"

**Question 3 Issues Still to be Resolved —**

- Is 'Firm Transmission Service' a FERC defined term? Firm Point-to-Point Transmission Service? Firm Network Transmission Service?
  - This issue may be resolved by the question 11 sub-team.
- Is loss of local load acceptable? Sub-team suggested changes rely on some degree of acceptability, which we have tried to quantify in performance based terms.
  - This issue may be resolved by the question 11 sub-team.
- R.3.3.2.1 Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. Is this of any value if we don't specify limits?
  - The SDT is gathering data on limits so as to address Order 693 directives on this issue. The concept is to gather the data for some period of time and then write a limit into a revision of TPL-001.
  - The SDT is undecided on whether duration needs to be included.
- Where do UVLS and UFLS belong?

**Question 3 Resolution —** The SDT could not reach resolution on these issues. These issues will be resolved through e-mail and conference call prior to the next meeting.

**Question 7 Summary —** Numerous format-related and content-related comments were received and have been summarized in Chifong's e-mail to the list server.

Many commenters want to see only one table. Doug Hohlbaugh had indicated previously that he would work on a single table scheme if there was support for it.

**Question 7 Recommendations —** The sub-team has proposed changes for some of the comments as shown in Chifong's e-mail. Many others, however, remain unresolved.

**Question 7 Resolution —** The SDT wants to see what a single table will look like before they agree to such an approach. Doug will work on a single table solution and present it at the St. Louis meeting.

**Action Item —** Doug will present a single table proposal to the SDT at the next meeting.

**Question 8 Summary —** By a margin of 42 percent yes, 58 percent no (ignoring the votes that say both yes and no and the blank votes), the industry voted against the definition of bus-tie breaker. (If the additional votes for groups are added the margin is still 39 percent yes, 61 percent no.)

The most popular revised definition is "A breaker that divides a bus section with multiple tap points into two bus sections". This was supported by BCTC, Columbia Grid, Idaho Power Company, Modesto Irrigation District, OPUC, Pacific Gas and Electric, Progress Energy Carolinas, Public Service of New Mexico, Puget Sound Energy Inc.,Sierra Pacific Power Company/Nevada Power, SMUD, Southern California Edison, SRP, Transmission Agency of Northern California, Tri-State G&T, Tucson Electric Power Company, and US Bureau of Reclamation but there were several others suggested changes as well.

**Question 8 Recommendation —** The sub-team is recommending the following changed definition:

*Bus-tie Breaker***:** A circuit breaker that is positioned to connect two individual substation bus configurations. Substation bus configurations can contain ring-bus, breaker-and-a-half, double bus-double breaker, double bus-single breaker schemes or straight bus with multiple tap points.

**Question 8 Resolution —** This issue will be resolved through e-mail and conference call prior to the next meeting. The SDT is debating whether bus-tie is the correct terminology.

**Question 9 Summary —** Industry opinion on Question 9 supported the more stringent requirement for non-bus-tie breakers rated above 300 kV with with 55 percent voting yes and 45 percent voting no (if those voting yes and no and those with blank votes are ignored.) If the additional votes associated with groups are added to the totals, the support for the more stringent requirement for non-bus-tie breakers rated above 300 kV increases with 67 percent voting yes and 33 percent voting no.

Nonetheless, it should be noted that the 16 yes and no votes (21 if additional votes for groups are counted) are sufficient to swing the results and the comments against the more stringent requirement were quite plaintive.

**Question 9 Recommendation —**While there are a significant number of parties that commented negatively about the higher system performance requirement for non-bus tie breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement. Therefore, it is recommended that the SDT move forward with the higher system performance requirement for loss of non-bus tie breakers above 300 kV.

**Question 9 Resolution —** The SDT accepted the sub-team recommendation.

**Question 11 Summary** — Comments on question 11 were all over the map. Many commenters are still complaining about not tripping firm transmission service while tripping firm load.

64 commenters are concerned that System adjustment after the first N-1 contingency and before the second N-1 contingency should allow curtailing firm transmission service and firm load in anticipation of the next contingency. The old footnote b or something similar (pertaining to preparation for the next contingency) should be added.

**Question 11 Recommendation —** The sub-team made numerous recommendations which are summarized in a table in Chifong's e-mail.

**Question 11 Resolution** — The SDT feels that many of the comments can be cleared up if the issue of firm transmission service versus firm load can be cleared up. Industry must understand that the standards are for reliability and not markets. A new sub-team was formed to address these issues and propose a solution to the SDT at the next meeting. The sub-team will be made up of Charles Long (lead), Bill Harm, Bob Pierce, Ron Mazur, and Chifong Thomas.

**c. Team C — Darrin Church**

This sub-team was assigned questions 5 and 15.

**Question 5 Summary** — The industry was divided on the need for Requirements 9 through 14. Many felt that this data was mandated in the MOD standards and thus not needed in TPL. They are concerned about possible double jeopardy.

**Question 5 Recommendation —** The sub-team wants to ensure that planners get all of the data that they need and that there is no possible double jeopardy in the requirements. Planners are currently getting what they need through a combination of OATT, regional data collection, MOD standards, and current operating practices. Therefore, the sub-team is recommending that R9 through R14 be deleted and a new sub-requirement be added to R1 as follows:

R1.1 — Models shall include, if specifically known, planned outages and long duration forced outages of generation and transmission facilities, with consideration of spare equipment strategy. Models shall also include new planned facilities and changes to existing facilities for each year of the Near-Term and Long-Term Planning Horizon, including but not limited to Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment, control devices, and new technologies.

In addition, any perceived gaps in MOD standards should be officially submitted to NERC as issues and entered in the Issues Database so that they can be incorporated into the SAR for the revisions to MOD.

**Question 5 Resolution** — The SDT supports the sub-team recommendation although the words in R1.1 need to be adjusted based on the discussion at this meeting.

**Question 15** — Responses to comments on question 15 will be answered after the other comments and suggested changes have been agreed upon by the SDT.

**d. Team D — Bob Millard**
This sub-team was assigned questions 10, 12, 13, and 14.

**Question 10 Summary and Recommendation** — The sub-team proposed changes to the requirements on sensitivity based on the industry comments received. These were distributed in a redlined roadmap prior to the meeting.

- R2.1.3 was changed — concept was included in R2.1.1 and R2.1.2
- Similar changes were made in the stability section.
- R2.1.4 was deleted — it was an optional requirement that couldn't have been enforced.
- R2.7.2 was deleted as not appropriate for a reliability standard.

**Question 10 Resolution** —The SDT generally agreed with the recommendation but requested the sub-team to revise the wording based on the discussion at this meeting.

**Question 12 Summary** — There were approximately 40 responses and the dollar values came in at approximately $500K for the initial response and $250K for on-going costs. In addition, it was estimated that it would take entities approximately 2 to 3 years to 'catch up' to the new requirements.

**Question 13 Summary** — There were approximately 40 responses. Several entities said that the costs for this item were bundled in their response to question 12. Several others stated that they simply didn't know how much it would cost them yet. Those who did respond estimated an initial cost of $100K and an on-going cost of approximately $80K.

**Question 14 Summary** — Several respondents stated that they thought the revised standard was essentially requiring new construction. RTOs stated that there would be minimal cost and time involved as they are already doing the things that will be required. Key elements cited by several respondents as directly contributing to their costs were the revised handling of N-1-1 contingencies and line plus generator tripping. Costs ranged from $500M to $1B over a period of at least 10 years.

**Questions 12–14 Resolution** — The SDT is very cognizant of the potential problems and costs. They are also concerned with the lack of available, experienced manpower, equipment, and tight capital markets. The response to the commenters will be to say 'Thank you for your response. The SDT will consider your data in making their final decision."

In reviewing the industry comments, it was clear that there is still some misunderstanding as to what needs to be done, when it needs to be done, and how the different analyses fit together. This sub-team was tasked with devising diagrams explaining the process for use in the SDT's next workshop.

**Action Item —** Team 'D' is tasked with coming up with diagrams explaining the planning process under TPL-001-1 in time for the next TPL Workshop.

### 5. Review Protection Sub-team Proposal to Add Requirements — Brian Keel

Time did not permit a report on this item and it will be carried over to the next meeting.

### 6. Requirements for Assessment Case — John Odom

Time did not permit a report on this item and it will be carried over to the next meeting.

### 7. Review Proposed VSL — Doug Hohlbaugh, Bob Millard, Tom Gentile

Time did not permit a report on this item and it will be carried over to the next meeting.

### 8. Review Implementation Plan — Bernie Pasternack

Time did not permit a report on this item and it will be carried over to the next meeting.

### 9. Discuss WECC Common Right-of-Way Approach

Time did not permit a report on this item and it will be carried over to the next meeting.

### 10. Review Proposed Change to R2.5 — Bob Jones

Time did not permit a report on this item and it will be carried over to the next meeting.

### 11. Review Comments on Measures

Time did not permit a report on this item and it will be carried over to the next meeting.

## 12. Next Steps — John Odom

Sub-teams should now prepare responses to industry comments wherever the SDT has finalized a decision. These responses should be ready by the next meeting.

There will be a conference call scheduled between the Austin and St. Louis meetings to discuss remaining issues brought out by industry comments.

## 13. Next Meetings

**a.** Conference call and WebEx on Monday, November 10, 2008 from 11 a.m.–2 p.m. EST to discuss topics brought up in industry comments that must be resolved in order to proceed. Details to follow.

**b.** Face-to-face meeting in St. Louis, MO on Monday, November 17, 2008 from 1:30–5 p.m. CST; Tuesday, November 18, 2008 and Wednesday, November 19, 2008 from 8 a.m.–5 p.m. CST both days. The meeting announcement has been distributed as well as information on alternate hotels if the primary hotel is filled.

**c.** Face-to-face-meeting in Charlotte, NC (tentative location — but dates set) on Wednesday, December 10, 2008 from 8 a.m.–5 p.m. EST and Thursday, December 11, 2008 from 8 a.m.–noon EST. Fall back location is Atlanta. The meeting announcement has been distributed.

## 14. Action Items and Schedule — Ed Dobrowolski

The following action items were developed during this meeting:

- Team D will double check the proposed changes to the sensitivity requirements suggested by Team A prior to the next meeting.
- Doug will present a single table proposal to the SDT at the next meeting.
- Team ‘D’ is tasked with coming up with diagrams explaining the planning process under TPL-001-1 in time for the next TPL Workshop.

The project schedule calls for the SDT to make its next submittal by December 4, 2008.

## 15. Adjourn

The Chair thanked LCRA for their hospitality and adjourned the meeting at 4 p.m. CDT on Wednesday, October 29, 2008.