

## Minutes of the TADSTF January 24-25, 2007, Atlanta Meeting

### Participants:

Jean-Marie Gagnon, Chair, Hydro-Quebec TransEnergie  
Jim Robinson, PPL Electric Utilities  
Brian Keel, Salt River Project  
Mike Pakeltis, CenterPoint Energy  
Jason Shaver, American Transmission Company  
Jeff Mitchell, ReliabilityFirst  
Pete Harris, ISO-NE  
Peter Gelineau, Canadian Electricity Association  
Ed Pfeiffer, Ameren  
Gary Brinkworth, City of Tallahassee  
Jake Langthorn, OG&E  
Mark Lauby, NERC  
John Seelke, NERC

1. Administrative. Chair Jean-Marie Gagnon welcomed the group. Eleven (11) TADSTF members were present for subsequent voting on issues. John Seelke reviewed the NERC Antitrust Compliance Guidelines. On motion, the minutes of the December 20, 2006 conference call were unanimously approved for posting. John Seelke reviewed the status of work on a draft NERC data rule under which TADS (and all data requests) would be mandated. He briefed the members on the planned discussions with EIA and FERC Jan 31 on form EIA 411.
2. OG&E Transmission Outages Data Collection. Jake Langthorn presented a summary of the transmission data collection for OG&E and SPP. Data collected by both entities is used for operational purposes, but is not recorded in a data base.
3. Planned Outage Data “Pro” and “Con” Discussion. A “pro” presentation was made by Jeff Mitchell and Jason Shaver, with Brian Keel and Mike Pakeltis giving separate “con” presentations. One point not included in the “pro” presentation was raised by Jim Robinson. He cited standard TPL-003-0, Requirement R1.3.12, which states:

Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

Jim advocated the collection of planned outage data so that the magnitude of planned outages could be related to load levels to assist Transmission Planners determine compliance with this requirement.

While a summary of the pro and con points does not give justice to the rigorous debate, the table below summarizes the major points:

<b>Collect Planned Outage Data Because:</b>	<b>Don't Collect Planned Outage Data Because:</b>
Most utilities collect planned outage data so little or no additional burden is imposed by requiring it to be reported. Without planned outage data, transmission system availability cannot be calculated, and a trend of this statistic is a useful indicator.	Trending system unavailability has a potential negative unintended consequence. Since planned outages comprise the largest part of unavailability, a Transmission Owner could maximize system availability by (a) reducing planned outages, which could (b) increase forced outages but (c) meet a goal of increased availability. <b>The EPRI Grid Reliability project found that planned outages were reported as less attainable through participant surveys than forced outages.</b>
Planned outage data captures the amount of maintenance performed. With planned outage data, the relationship between planned and forced outages can be shown; i.e., more planned outages should reduce forced outages.	Planned outage data doesn't capture live-line maintenance. Planned outages are subject to many Transmission Owner variables (weather, crew availability, and budgets) so true comparisons cannot be made.
Planned outage data allows a Transmission Planner to correlate historical planned outage data and load data and thus be able to implement meet TPL standards.	Planned outages are only allowed when system conditions permit them and therefore do not jeopardize reliability.

After vigorous debate, a vote was taken on the following proposition: NERC will collect mandatory planned outage data. The result was: 5 yeas, 5 nays, and 1 abstention. Therefore, the motion did not carry. Conversely, a similar motion to not include planned outages would not have passed either. Therefore, the collection of planned outage data issue will be taken to the Planning Committee for discussion and direction. However, it was recognized that a Region may, within the limitations of its own rules, impose stricter outage collection standards on Transmission Owners in its Region than NERC imposes on all Transmission Owners.

4. Survey of Transformers and DC Lines/Terminals. John Seelke presented the results of the survey completed for WECC, ERCOT, and the Eastern Interconnection on transformers by voltage class and DC lines and terminations. The survey was done by examining data in power flows of 2006/2007 for each region (WECC by Brian Keel, ERCOT by Ken Donohoo, and Eastern Interconnection by Eric Allen). The intent of the survey was to provide a basis for setting inclusion criteria for transformers and DC facilities.
  - a. Transformers. The previously agreed upon transformer inclusion criterion required a low-side voltage  $\geq 200$  kV. The TF elected to maintain this criterion (without a vote) because it is consistent with the inclusion criteria for AC lines  $\geq 200$  kV. Including transformers with less than a 200 kV low-side voltage would include transmission components below the TADS bulk-power 200 kV framework. For example, if 345/138 kV transformers are included, why not include the 138 kV circuits that are connected to those transformers? Although ERCOT has no transformers that meet the  $\geq 200$  kV low-side

inclusion criterion, the TF again recognized that a Region could establish its own inclusion criteria for any reporting element that exceeds NERC criteria.

- b. DC Lines and Terminals. Two inclusion criterion were proposed for DC lines and terminals:
  - i. Include DC lines and terminals with AC termination (converter) voltages of  $\geq 200$  kV on each terminal. This criterion is consistent with the transformer inclusion reasoning.
  - ii. Include DC lines DC voltages  $\geq +/- 200$  kV. This criterion recognized that higher DC line voltages are indicative of higher power transfer level. It is silent on the inclusion of terminals.

By consensus, it was agreed that each member would cast one vote for either alternative. Six members voted for the first alternative, four voted for the second, and one member abstained. Thus, the first alternative became the inclusion criterion for DC lines and terminals.

5. Other Components. Ed Pfeiffer and Peter Gelineau made presentations on whether other component availability data should be collected. Ed's proposition was that no additional component-specific data should be collected, but that other component outages should be incorporated into cause codes that could describe why a line or transformer is forced out. Peter's presentation examined the relevance of other component data collected by CEA in the  $\geq 200$  kV range. Although CEA data was not precisely compatible because CEA voltage classes are not limited to low-side voltages, Peter's analysis showed that circuit breakers were the only additional component that the TF might consider since their outage frequency and repair time were comparable to transformers. Since transformer data will be collected, why not circuit breaker data?

The discussion that followed re-examined the rationale for collecting transformer data. Jeff Mitchell pointed out that our data should be assessing the availability of branches. Branches are defined by the transmission elements between breakers. Most network transformers in our criterion are branches, and attempting to cull out those that are not would cause confusion in the data collection effort. Circuit breakers are not branches. It was agreed that the definition of a "circuit" and a "transformer" is lacking at this point.

6. Metrics.
  - a. Brian Keel, Jason Shaver, and Peter Gelineau led a discussion on metrics. Their framework included an assumption that circuit and transformer attribute data would be collected for later analysis, a decision that the TF had not yet agreed upon. A vote was taken as to whether circuit and transformer specific outage data should be reported or whether such data should be rolled-up to a class level (e.g., report data for all AC circuits at the in the 200-299 kV range). The vote was 8-3 in favor of only reporting class level data. Again, while a Region may require the reporting of detailed line and circuit attribute data, NERC will not. Thereafter, the discussion focused on what class metrics should be reported. The group agreed (without a vote) on the following:

- i. Frequency and duration metrics would adopt the EPRI framework but add the CEA median duration metric. It was agreed that the computation of a median metric would require the reporting of information specific to each forced outage, but that the circuits or transformers which are outaged would not be identified.
  - ii. These same frequency and duration metrics would be reported by cause code and outage mode classification.
  - iii. With respect to impact measures, the group decided not to record whether or not an event resulted in a load loss (Y/N). This was a reversal of the TF's previous decision. The reason the decision was reversed is that even this seemingly simple information may not be known by Transmission Owners who are not vertically-integrated with Distribution Providers. Jason Shaver asked whether or not NERC could require Distribution Providers to submit load loss data. While John Seelke felt that NERC could, the ensuing discussion on the mechanics of collecting that data lead to a consensus that it could be very difficult and a costly route to take; therefore, this impact measure was dropped. Ed Pfeiffer pointed out that load loss is not the only impact of transmission unavailability. Loss of generation and curtailment of firm transmission service are other significant impacts that the TF had decided not to pursue due to data collection difficulties. In the end, only OE-417 data was left as a viable impact measure. John Seelke agreed to research the frequency of OE-417 reports.
- b. Jim Robinson led a discussion on additional outage event data that might be useful to Transmission Planners, especially with respect to the TPL standards. The alternative of reporting by single element only was not approved, but the framework of reporting by element and event ID was approved (consensus only, no vote taken). For each event, the following data would be reported:
- i. If the event involved a fault, whether the target of the fault was a phase or ground target
  - ii. An event type would be recorded. Jim's proposal has 31 event types that were taken from the TPL standards. This list would need to be supplemented to include regional-specific standards such as those in WECC.

Jim had an additional framework to present that was not included in the meeting materials (by zone of protection, circuit breaker to circuit breaker), and this was deferred for future discussion.

- c. John Seelke's OE-417 material was discussed when agenda item 6.a.i was discussed.

John Seelke agreed to write-up a metrics documents that reflected the framework described above. This document would itemize the data that would be reported to support those metrics. It would show what metrics and data are reported by

various entities: WECC, ECAR, EPRI, SGS, PA Consulting, EIA, and CEA. Mike Pakeltis will provide John with PA information.

7. Data Reporting Mechanics. This discussion focused on the roles of the Regions and NERC in the reporting mechanics.
  - a. Would Transmission Owners report data to NERC or the Regions?
  - b. Would NERC or the Regions perform initial data validation, checking for obvious data errors?
  - c. Would Transmission Owner data reported to the Regions be combined before reporting it to NERC so that no Transmission Owner's data could be identified by NERC, or would Regions report Transmission Owner level data to NERC?
  - d. Would NERC or the Regions perform periodic validation audits of Transmission Owners submitting the data, verifying such information such as whether they are reporting all required information, whether they are properly using cause codes, etc.?

A vote was taken on the limited motion that the Regions would collect the data and perform initial data validation (items a. and b. above). This motion passed with 8 yeas, 2 nays, and one abstention. The remaining topics were deferred.

8. Confidentiality of Data. This topic was not discussed due to time constraints.
9. Definitions. The material prepared for this topic was not discussed. However, the definitions team (Brian Keel, Jason Shaver, and Peter Gelineau) agreed to complete the document by including ECAR definitions. (Jeff Mitchell is to transmit ECAR definitions to Brian Keel). This group is also to develop an initial set of definitions for the entire TADSTF to review, including:
  - a. What's a "circuit or a "transformer"?
  - b. What's a forced outage?
  - c. How are partial outages treated?
  - d. What are the recommended cause codes and outage modes?
10. Draft Report Outline. This topic was not discussed due to time constraints.
11. Schedule for Future Work
  - a. Surveys. It was agreed that it was pre-mature to perform surveys of either Transmission Owners or Regions until we have our proposal better defined.
  - b. Additional work left open:
    - i. Jim Robinson's zone of protection reporting framework (see paragraph 6.b).
    - ii. Complete the discussion of the roles of NERC/Regions in reporting (see paragraph 7).
  - c. Conference Calls. The following calls will be scheduled by Seelke

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- i. Feb. 5, 3 p.m-5 p.m. EST: Definitions team (Keel, Shaver, Gelineau) plus Pete Harris and Mark Lauby
  - ii. Feb. 12, 4 p.m-6 p.m. EST: Entire TADSTF. Topic: Metrics and Data per Seelke's assignments in paragraph 6.
  - iii. Feb. 19, 3 p.m-5 p.m. EST: Entire TADSTF. Topic: Definitions per the definition team's assignments in paragraph 9.
  - iv. Mar. 5, 3 p.m-5 p.m. EST: Entire TADSTF. Topic: Review of the report due to the Planning Committee on March 7.
  - v. Mar. 23, 11 a.m.-12:30 p.m. EST: Entire TADSTF. Topic: Verbal report about the comments by the Planning Committee on the TADS report which will be presented at the PC's March 21-22 meeting.
  - vi. Apr. 10, 3 p.m-5 p.m. EST: Entire TADSTF. Topic: Possible comments on form EIA 411, Schedule 7.
- d. Meetings:
- i. Feb. 26-28 in Dallas: **Tentative schedule**. Meeting will start 12 noon on Feb. 26 and end at 12 noon on Feb. 28. (Note that the present meeting posting on NERC's Website will be changed when these date are confirmed.) This is our last meeting before the report is due.
  - ii. Apr. 23-25 in Chicago: **Tentative** meeting that will start 12 noon on Apr. 23 and end at 12 noon on Apr. 25. This meeting is set to incorporate the PC's recommendations into our March 7 report.

Respectively submitted,

John Seelke

Secretary