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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Availability Data System Phase II Final Report

Prepared by the Transmission Availability Data System Task Force for the NERC Planning Committee

Approved by the Planning Committee on: September 11, 2008

to ensure the reliability of the bulk power system

September 11, 2008

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1. Executive Summary

1.1. Background

On October 23, 2007, the NERC Board of Trustees approved the mandatory implementation of Phase I Transmission Availability Data System (TADS) which required U.S. Transmission Owners[1] (TOs) on the NERC Compliance Registry to report Automatic Outages beginning in 2008 in a NERC-prescribed format for the following Elements:[2]

- AC Circuits ≥ 200 kV (Overhead and Underground Circuits). Radial circuits are included.
- Transformers with ≥ 200 kV low-side voltage
- AC/DC Back-to-Back Converters with ≥ 200 kV AC voltage, both sides
- DC Circuits with ≥ +/-200 kV DC voltage

Phase I was developed by the Transmission Availability Data System Task Force (TADSTF, or TF) of NERC's Planning Committee. The details of Phase I are described in the *Transmission Availability Data System Revised Final Report* dated September 26, 2007, which may be downloaded at http://www.nerc.com/filez/tadstf.html. That report included a commitment by the TF to develop Phase II:

> "Phase II will add a requirement that TOs report scheduled outage and manual unscheduled outage data beginning in calendar year 2009. Phase II was added as a result of discussions with officials of the U.S. Energy Information Administration (EIA) on May 16, 2007, and we are recommending it in order to have TADS serve as a single source to NERC and EIA for transmission outage data. We will propose that outage reporting framework to the Planning Committee at its March 2008 meeting."[3]

1.2. Changes from the Preliminary Phase II Report

A *Transmission Availability Data System Preliminary Phase II Report* dated March 13, 2008 ("preliminary Phase II report") was approved by the Planning Committee. In addition to considering additional outage reporting, the preliminary Phase II report also addresses the collection of outage data for DC Circuits in the +/-100-199 kV range, which EIA collects but which TADS does not. Finally, the preliminary Phase II report addressed two issues that were not previously addressed in Phase I which affect both Phase I and Phase II: (i) NERC authority to review individual Transmission Owner TADS data submittals, and (ii) the future management of TADS activities.

The preliminary Phase II report, along with a *TADS Data Reporting Instruction Manual* dated April 4, 2008 ("Manual"), were posted for comment as required by Section 1600 of NERC's *Rules of Procedure*.[4] Appendix 3 describes the comments received and our

[1] Non-U.S. Transmission Owners were asked for Phase I TADS data, but their response is voluntary.
[2] Definitions in Appendix 2 are capitalized in this report.
[3] See p. 1 of the September 26, 2007 report.
[4] All materials related to the request for comments are available at http://www.nerc.com/filez/tadstf.html.

responses to those comments. We received comments from 64 Transmission Owners plus five other entities.[5] In this final Phase II report, we included several changes to Phase II that responded to the comments received:

1. In response to numerous comments expressing concern about the Phase II schedule, we delayed implementation by one-year. Phase II TADS will now require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011 (i.e., Non-Automatic Outages from January 1, 2010 through December 31, 2010). See Appendix 3, Section 3.1, pp. 7-8.
2. In response to concerns as to whether Phase II TADS data is a benefit to NERC, we recommended that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. We also recommended that the benefits of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan**.** Furthermore, we recommended that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees. See Appendix 3, Section 3.2, pp. 8-10.
3. In response to Nebraska Public Power District's request that we add a "forced outage rate" metric, we declined to add their suggested formula as a general metric because it may be defined differently by different TOs. However, we will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric. See Appendix 3, Section 3.6. p. 17.
4. In response to National Grid's comment that TOs should be allowed to enter data in local time instead of Universal Coordinated Time (UTC) since webTADS has this capability, we will modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. We will clarify this in a future update of the Manual. See Appendix 3, Section 3.9, p. 22.

1.3. Phase II Design

Phase II defines a framework for the collection of Non-Automatic Outages which complements the Phase I Automatic Outage structure. Phase II thus completes the specification of a NERC-wide approach to quantify or measure system performance and reliability. Phase II has two categories of Non-Automatic Outages, along with several Cause Codes for each category:

[5] The 64 Transmission Owners providing comments represented 31.4% of all TOs that will provide Phase I data.

- Planned Outage: A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation of an outage of another TADS Element are not reportable.[6]

  Planned Outage Cause Codes:
  - Maintenance and Construction
  - Third-Party Request
  - Other Planned Outage

- Operational Outage: A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

  Operational Outage Cause Codes:
  - Emergency
  - System Voltage Limit Mitigation
  - System Operating Limit Mitigation, excluding System Voltage Limit Mitigation
  - Other Operational Outage

With regard to collecting outage data for DC Circuits in the +/-100-199 kV range which is now included EIA Form 411, Schedule 7, there is only one DC Circuit in North America that falls in this category. Reporting outages in this single voltage class would display the metrics of a single TO. Our policy is not to display metrics if the TO's name and confidential information could be identified. Therefore, we will not include this additional voltage class in Phase II.

While the collection of Non-Automatic Outage data by Transmission Owners is a mixed practice, the TF noted several uses as well as limitations associated with Non-Automatic Outage data. The list below begins with the Non-Automatic Outage data uses.

1. Non-Automatic Outage data will complement Phase I Automatic Outage data, resulting in our ability to capture almost all transmission Element outages. Since almost all Element outages will be recorded, the calculation of certain Phase I metrics – the Mean Time Between Sustained Outages, or mean "Up Time" (also referred to as Mean Time Between Failure) and Availability Percentage – will now be more accurate.
2. Complete transmission outage information may influence NERC Reliability Standards development.
3. Complete transmission outage information could allow for improved system analysis by bridging gaps between the operating environment and planning assumptions.
4. For U.S. Transmission Owners who are subject to EIA reporting requirements, the reporting of Non-Automatic Outages to NERC could avoid a duplicative reporting

[6] The exclusion of "setup switching" or "restoration switching" outages recognizes that they are not part of an intended Planned Outage and should not be reported.

requirement to EIA. The data from Phase I and Phase II TADS can be summarized by NERC to provide EIA the same data it now requires in EIA Form 411, Schedule 7, except for data on DC Circuits in the +/- 100-199 kV range.

5. No Reliability Standard or NERC rule (in NERC's *Rules of Procedure*) requires the systematic recording of historic system topology for the purpose of analyzing events. TADS will begin to fill this need by collecting both Automatic and Non-Automatic Outage data.

These are some limitations in the use of Non-Automatic Outage data.

1. Trending of Non-Automatic Outage metrics *within* a Regional Entity may be useful, but comparisons *between* Regional Entities are inappropriate for the same reasons provided in the Phase I report.
2. Trending Planned Outages is not an indication of the total amount of maintenance or construction being performed on the TADS Elements. For example, live–line circuit maintenance and substation equipment maintenance that does not require an Element outage is not captured. Therefore, correlations between Phase I Automatic Outages and Phase II Non-Automatic Planned Outages should be approached with caution.

With respect to EIA Form 411, Schedule 7, the reporting of this data to EIA was made voluntary for 2008 (for 2007 data), with the status of Schedule 7 beyond 2008 to be resolved in future discussions among NERC, EIA, federal users of Schedule 7 data, and Office of Management and Budget (OMB) with the possible substitution of information derived from TADS for Schedule 7 data. OMB was to be the final arbiter. NERC held one meeting with EIA and other federal users on February 7, 2008.

EIA's follow-up March 11, 2008 comments on TADS were as follows: NERC was asked to provide information on how TADS data reporting would be validated to ensure quality information and how TADS data reporting would be enforced; FERC staff attendees expressed the desire for TADS to be expanded to transmission voltages of 100 kV and higher; and further discussions would be required regarding TADS data confidentiality.

Following those March 11 comments, NERC and EIA agreed to the following: EIA will accept summary Schedule 7 data, thereby eliminating the need to address their previous confidentiality concerns; Schedule 7 should remain voluntary through 2010, with NERC providing EIA with the voluntary data it receives from the regions; mandating Schedule 7 will be re-addressed in the Electricity 2011 project, which will take up the re-authorization of EIA data collection forms, including Form 411.

1.4. Who Must Report Phase II Data

Based upon some of the comments received, we felt that we should clarify which TOs are required to report Phase II TADS data. The submission of Phase II TADS data will be mandatory for all U.S. Transmission Owners who are on the NERC Compliance Registry. Non-U.S. Transmission Owners on the NERC Compliance Registry who are also NERC members are required to comply with NERC's *Rules of Procedure*, and because Phase II TADS data was requested in accordance with Section 1600, these non-U.S. Transmission Owners too must provide Phase II TADS data.[7]

1.5. Phase II Data and Metrics

We used the same format for Non-Automatic Outage data collection as we did for Automatic Outage data. In addition to a description of the Element that had an outage, Non-Automatic Outages only require the reporting of an Outage Start Time, an Outage Duration, an outage category (Planned or Operational), and a Cause Code.[8] While less data per outage is required for a Non-Automatic Outage as compared to an Automatic Outage, the number of Non-Automatic Outages is expected to be significantly greater than the number of Automatic Outages.

The following Phase II metrics will be calculated:

1. Non-Automatic Outage frequency per Element (Planned, Operational, and total).
2. For Planned and Operational Outages:
    i. Outage Duration per Element.
    ii. Mean Element outage time
    iii. Median Element outage time
3. Percent of Elements with zero Non-Automatic Outages.
4. The maximum percentage of simultaneous Element Outages. Since TADS will have almost all outage data including outage start time and duration, we will be able to calculate the maximum percentage of simultaneous outages that occurred for an Element on a Transmission Owner or Regional Entity basis.

Some TOs may want to develop metrics that combine Automatic Outage data with Non-Automatic Outage data. For example, the EIA's term for "unscheduled outages" combines Automatic Outage Data with Operational Outages having an Emergency Outage Cause Code. Some TOs might consider this data to be the basis of a "forced outage rate" calculation, while others may consider different parameters in the term "forced outage rate." We will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric.

1.6. Additional Phase II Recommendations

In the Phase I report, we noted that the Regional Entities will be spot checking TO-submitted TADS data for potential errors. We propose conducting data validation

[7] Phase I was approved by the NERC Board of Trustees prior to the addition of Section 1600 to the *Rules of Procedure.* Because NERC's Phase I TADS approval relied upon Section 39.2(d) of the Federal Energy Regulatory Commission's regulations, 18 C.F.R. § 39.2(d), Phase I is mandatory on all U.S. Transmission Owners. However, most non-U.S. Transmission Owners have indicated that they will voluntarily comply with Phase I.

[8] Non-Automatic Outages do not require an Event ID Code, an AC Multi-Owner Common Structure Flag, a Fault Type, two Cause Codes (Initiating and Sustained), and an Outage Mode Code.

webTADS data may also test their ability to input actual or dummy 2009 data. Dry-run testing is completely optional, but we believe that TOs who avail themselves of this option will be better prepared for 2010 implementation.

Phase II TADS Timetable for 2010 Reporting Year

Late Nov. 2008	NERC completes Phase II webTADS requirements and submits to OATI.
Feb. 1, 2009	NERC will publish final specifications for data input and error checking so that TOs may use the specifications to modify their data collection systems.
Feb 1-July 1, 2009	OATI will complete changes to webTADS for Phase II, including system testing with dummy data.
July 1-Dec. 1, 2009	NERC and OATI will conduct Phase II webTADS training. We recognize that some TOs will have different personnel entering Non-Automatic Outage data into webTADS, and therefore we have allowed a long training period.
July 1-Dec. 31, 2009	"Dry run" data entry permitted into webTADS by TOs for any part of their actual or dummy 2009 data. Any 2009 Phase II data which a TO enters will not be retained in webTADS after December 31, 2009.
Jan. 1, 2010	TOs may submit Phase II data in webTADS
Mar. 1, 2011	TOs complete data entry of Phase II data into webTADS

2. Phase II Design

2.1. Non-Automatic Outages

A Non-Automatic Outage is defined as an outage which results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

- For comparison, an Automatic Outage is defined as an outage which results from the automatic operation of switching device, causing an Element to change from an In-Service State to a not In-Service State. A successful AC single-pole (phase) reclosing event is not an Automatic Outage.

We wanted the Non-Automatic Outage framework to have the same "look and feel" as the Automatic Outage framework we adopted in Phase I so that Transmission Owners could easily add it to their ongoing Phase I collection. The final TADS structure for Phase II accomplishes this goal. We also wanted Phase II to be compatible with EIA transmission outage needs. While we examined the same outage collection frameworks described in our Phase I report, in the end we chose a Phase II structure very similar to the structure recommended by the Electric Power Research Institute reference listed in the Phase I report.[9]

For TADS, Non-Automatic Outages are subdivided into two categories: Planned Outages and Operational Outages, which are defined below.

- <u>Planned Outage</u>: A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation or restoration of an outage of another TADS Element are not reportable.[10]
- <u>Operational Outage</u>: A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

2.1.1. Planned Outage Cause Codes

We adopted three Planned Outage Cause Codes:

1. <u>Maintenance and Construction</u>: Use for Planned Outages associated with maintenance and construction of electric facilities, including testing. This includes requests from any entity that is defined in the NERC Functional Model.[11]

[9] See Section 2.2 of the *Transmission Availability Data System Revised Final Report* dated September 26, 2007.
[10] The exclusion of "setup switching" or "restoration switching outages recognizes that they are not part of an intended Planned Outage and should not be reported.
[11] The Functional Model is available at http://www.nerc.com/files/Functional_Model_Technical_Document_V3_for_OC_and_PC_approval_06De

2. Third-Party Request: Use for Planned Outages that are taken at the request of a third party such as highway departments, the Coast Guard, etc.

3. Other Planned Outage: Use for Planned Outages for reasons not included in the above list, including human error.

With respect to the Maintenance and Construction Cause Code, we considered separate codes for maintenance and construction. However, since in practice, the outage of a facility for maintenance is often scheduled to coincide with construction, we felt that asking TOs to distinguish between them would not be reasonable.

2.1.2. Operational Outage Cause Codes

We adopted four Operational Outage Cause Codes:

1. Emergency: Use for Operational Outages that are taken for the purpose of avoiding risk to human life, damage to equipment, damage to property, or similar threatening consequences.

2. System Voltage Limit Mitigation: Use for Operational Outages taken to maintain the voltage on the transmission system within desired levels (i.e., voltage control).[12]

3. System Operating Limit Mitigation, excluding System Voltage Limit Mitigation: Use for Operational Outages taken to keep the transmission system within System Operating Limits, except for System Voltage Limit Mitigation. The term "System Operating Limit" is defined in the NERC *Glossary of Terms Used in Reliability Standards* and is excerpted below.

   > "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:
   > - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
   > - Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
   > - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
   > - System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). "

   Do not include actions in the last category (System Voltage Limits) because this is included in the previous "System Voltage Limit Mitigation" Cause Code.

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c06.pdf. As an example, an outage is requested by a Generation Operator for purposes of completing an interconnection of its facilities would be classified in the Maintenance and Construction category. A Load-Serving Entity which requests an outage to make repairs to its substation would also be reported in this category.

[12] A separate Cause Code for System Voltage Limit Mitigation was required because we believe this will be a dominant Operational Outage cause.

4. Other Operational Outage: Use for Operational Outages for reasons not included in the above list, including human error.

2.2. Data for DC Circuits in the +/-100-199 kV Range

While TADS has a minimum voltage level of 200 kV for outage reporting, EIA collects DC Circuit data at the +/- 100-199 kV level.[13] There is only one DC Circuit in North America that falls in this category. Reporting outages in this single voltage class would display the metrics of a single TO. Our policy is not to display metrics if the TO's name and confidential information could be identified. Therefore, we will not include this additional voltage class in TADS Phase II.

2.3. Who Must Report Phase II Data

Based upon some of the comments received, we felt that we should clarify which TOs are required to report Phase II TADS data. The submission of Phase II TADS data will be mandatory for all U.S. Transmission Owners who are on the NERC Compliance Registry. Non-U.S. Transmission Owners on the NERC Compliance Registry who are also NERC members are required to comply with NERC's *Rules of Procedure*, and because Phase II TADS data was requested in accordance with Section 1600, these non-U.S. Transmission Owners too must provide Phase II TADS data.[14]

2.4. Intended Uses and Limitations of Non-Automatic Outage Data and Metrics

The collection of historic Non-Automatic Outage data by Transmission Owners is a mixed practice.

- EPRI recommends planned outage metrics for use in internal applications such as corporate strategic planning and reliability management but not for external applications such as benchmarking or regulatory assessment.
- Some regions, such as the former East Central Area Reliability (ECAR), Mid-America Interconnected Network (MAIN), and Mid-Continent Area Power Pool (MAPP) regions collected all transmission outages for over 20 years. However, no recommendations were made by them as a result of the collection and reporting of the planned outage data over that same period. They did make formal observations in their summary reports as to outage duration and cause.
- Five of the eight NERC regions submitted EIA Schedule 7 data in 2006 and 2007, which included unscheduled and scheduled outage data.
- Others have not collected such data for statistical purposes under the assumption that most Non-Automatic Outages are Planned Outages which are taken when reliability is not jeopardized. The Canadian Electricity Association (CEA)

[13] For AC Circuits, EIA and TADS both start at 200 kV.
[14] Phase I was approved by the NERC Board of Trustees prior to the addition of Section 1600 to the *Rules of Procedure*. Because NERC's Phase I TADS approval relied upon Section 39.2(d) of the Federal Energy Regulatory Commission's regulations, 18 C.F.R. § 39.2(d), Phase I is mandatory on all U.S. Transmission Owners. However, most non-U.S. Transmission Owners have indicated that they will voluntarily comply with Phase I.

collects equipment forced outage data that are consistent with the classification of TADS Automatic Outages plus Operational Outages. CEA has felt that the value of Planned Outage data is not commensurate with the effort involved in collecting it.

In the new NERC "electricity reliability organization" era, we believe NERC should collect almost all transmission outage data for several reasons. The list below begins with the Non-Automatic Outage data uses.

1. Non-Automatic Outage data will complement Phase I Automatic Outage data, resulting in our ability to capture almost all transmission Element outages. Since almost all Element outages will be recorded, the calculation of certain Phase I metrics (discussed in Section 4) will now be more accurate.

2. Complete transmission outage information may influence NERC Reliability Standards development.

3. Complete transmission outage information could allow for improved system analysis by bridging gaps between the operating environment and planning assumptions. For example, Transmission Planners could compare historical Planned Outages for a period with previously forecasted outages for the same period allowing them to assess whether their outage representation for planning is valid.[15] TOs, Transmission Planners, and Planning Coordinators could compare historic Planned Outages to historic load levels to determine the frequency of such outages during peak load periods.

   From a planning perspective, if planned outages are not properly accounted for in the planning of the system, insufficient facilities may be built, making day-to-day reliability worse. Several TPL standards (TPL-002-0, TPL-003-0, and TPL-004-0) have a requirement that planned outages be explicitly considered. In TPL-002-0, this is found in R1.3.12:

   > "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.

   Historical Planned Outage data could help Transmission Planners with this requirement.

4. For U.S. Transmission Owners who are subject to EIA reporting requirements, the reporting of Non-Automatic Outages to NERC could avoid a duplicative reporting requirement to EIA. The next section describes the present status of EIA Form 411, Schedule 7.

5. No Reliability Standard or NERC rule (in NERC's *Rules of Procedure*) requires the systematic recording of historic system topology for the purpose of analyzing events. TADS will begin to fill this need by collecting both Automatic and Non-Automatic Outage data. Since we only require the submission of TADS data

[15] To be clear, Phase II will *not* be collecting forecasted Planned Outage data; it will be collecting historic Planned Outage data.

annually, we recognize that the submission of TADS data into webTADS may not occur until months after an event. The requirement to collect TADS outage data means that TOs could, by special request from NERC, provide outage data if required to help NERC analyze an event, and the fact that such data will be entered into a structured TADS database will be helpful.

These are some limitations in the use of Non-Automatic Outage data.

1. Trending of Non-Automatic Outage metrics *within* a Regional Entity may be useful, but comparisons *between* Regional Entities are inappropriate for the same reasons provided in the Phase I report.

2. Trending Planned Outages is not an indication of the total amount of maintenance or construction being performed on the TADS Elements. Therefore, correlations between Phase I Automatic Outages and Phase II Non-Automatic Planned Outages should be approached with caution.

    - Maintenance and construction are bundled in our reporting for practicality as discussed previously, so maintenance is not captured separately.
    - A TADS Element maintenance and construction outage could be due to maintenance and construction on a non-TADS Element.
    - Planned Outage data does not capture the total amount of maintenance performed. For example, live–line circuit maintenance and substation equipment maintenance that does not require an Element outage is not captured.

2.5. Status of EIA Form 411, Schedule 7

EIA has indicated that it must receive the same type of data on EIA Form 411, Schedule 7, from TADS if TADS is to be an acceptable substitute for Schedule 7. In 2007, EIA asked that Form 411 be made mandatory, a requirement that would only affect U.S. Transmission Owners. NERC filed comments (see Appendix 1) with the Office of Management and Budget (OMB), asking that Schedule 7 either be made voluntary or eliminated altogether. As an alternative, NERC recommended using its TADS database to make available to EIA the same type of data on EIA Form 411. Following discussions between NERC, EIA, and OMB in late December 2007, Schedule 7 was made voluntary for 2008 (for 2007 data), with the status of Schedule 7 beyond 2008 to be resolved in future discussions among NERC, EIA, federal users of Schedule 7 data, and OMB about the possible substitution of information derived from TADS for Schedule 7 data. OMB was to be the final arbiter.

On February 7, 2008, an initial meeting was held among representatives from OMB, the Department of Energy (including EIA), the Department of Justice, the Federal Energy Regulatory Commission (FERC), and NERC staff to determine whether (a) TADS would meet the needs of federal users of transmission outage data, and (b) what barriers exist to making information derived from TADS available to federal users.

- On the first issue, EIA will solicit input from the federal user community on the adequacy of Phase I. With respect to Phase II, federal users will provide comments during the Phase II public comment period.

- On the second issue, from NERC's perspective, the main barrier to providing TADS data to federal users is ensuring that mechanisms are in place to protect confidential TADS data, including critical energy infrastructure information (CEII) and sensitive proprietary information from public access or public disclosure. Section 1500 of NERC's *Rules of Procedure* defines confidential information and sets forth the procedures for release of confidential information in NERC's possession.
  - A procedure for FERC (and other applicable electric reliability organization (ERO) governmental authorities) to request confidential information from NERC is set forth in Section 1505 of NERC's *Rules of Procedure*.[16]
  - NERC and EIA discussed the possibility of EIA requesting summarized non-confidential aggregated data and metrics from NERC and identifying NERC as the source of the data. In such a case, EIA would not have possession of confidential TADS data; instead, it would receive aggregated information produced by NERC. Information provided to EIA that might identify a single Transmission Owner's confidential information could either be removed or combined with data from another Voltage Class to prevent such disclosure. NERC and EIA agreed to continue discussions regarding these issues.
  - The Department of Justice representative did not make any comments.

Federal users were asked to provide comments to EIA by March 7, 2008 on (a) the adequacy of Phase I and (b) how to address NERC's concerns regarding confidentiality.

EIA's follow-up March 11, 2008 comments on TADS were as follows: NERC was asked to provide information on how TADS data reporting would be validated to ensure quality information and how TADS data reporting would be enforced; FERC staff attendees expressed the desire for TADS to be expanded to transmission voltages of 100 kV and higher; and further discussions would be required regarding TADS data confidentiality.

Following those March 11 comments, NERC and EIA agreed to the following: EIA will accept summary Schedule 7 data, thereby eliminating the need to address their previous confidentiality concerns; Schedule 7 should remain voluntary through 2010, with NERC providing EIA with the voluntary data it receives from the regions; mandating Schedule 7 will be re-addressed in the Electricity 2011 project, which will take up the re-authorization of EIA data collection forms, including Form 411.

TADS Phase I and Phase II can be used to derive the Schedule 7 requirements as shown in Figure 1 on the next page.[17] NERC can also meet the EIA time schedule for providing this data for 2011 reporting of 2010 data.

[16] Each ERO governmental authority would be able to access confidential information for Transmission Owners that it regulates, e.g., FERC would only be able to access TADS data for U.S. Transmission Owners, and an appropriate Canadian provincial regulatory body would only be able to access TADS data for its provincial Transmission Owners.

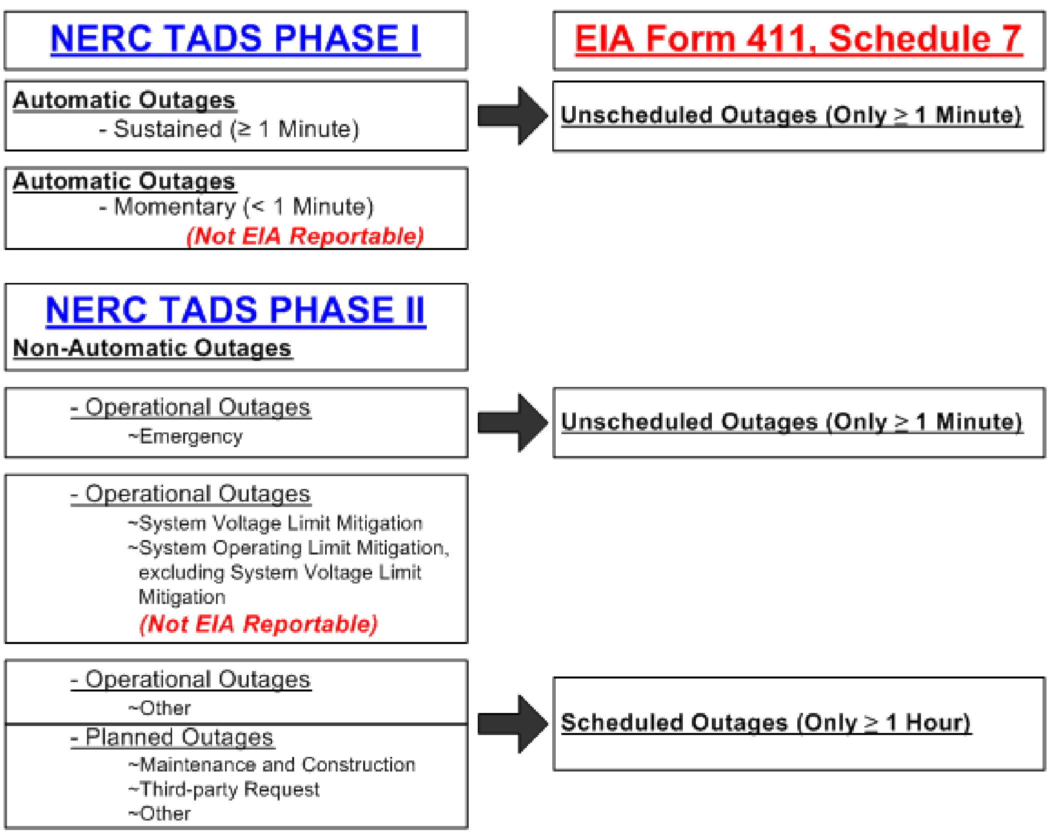
[17] As discussed in Section 2.2, we do not propose to collect TADS data for the one DC Circuit in the +/- 100-199 kV level which is now required in Schedule 7.

- Phase I TADS Sustained Outages and Phase II TADS Operational Outages classified as "Emergency" become Schedule 7 unscheduled outages. The Emergency-classified Operational Outage would be sorted by NERC to exclude outages that are less than one minute.
- Phase II TADS Planned Outages (all classifications) and Operational Outages classified as "Other" become EIA scheduled outages. By NERC sorting on the outage durations, we would exclude outages of less that one hour duration for EIA. Note that Phase II Planned Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation or restoration of an outage of another TADS Element will not be reported in TADS.

Certain TADS outage data will not be reportable to EIA:

- Phase I Momentary Outages
- Phase II Operational Outages classified as "System Voltage Limit Mitigation" and "System Operating Limits, excluding System Voltage Limit Mitigation."

Figure 1: NERC TADS Compared to EIA Form 411, Schedule 7



3. Phase II Data Reporting

Like Phase I, which reports each individual Automatic Outage, Phase II will require the reporting of each reportable Non-Automatic Outage. Outages will be reported for each Element type: AC Circuits, DC Circuits, Transformers, and AC/DC Back-to-Back Converters. However, the Phase II outage reporting will be simpler compared to Phase I.

Each Element outage will require the following data:

1. An Outage ID Code. This is a unique outage code assigned by the TO.
2. Data that defines the physical location of the Element. For example, for AC Circuits, the Substation Names that define the circuit are required, while for Transformers, the Substation Name where the Transformer is located is required. In addition, a TO Element Identifier, an alphanumeric name of the Element (such as a circuit number) is required to be provided by the Transmission Owner.
3. The Element's Voltage Class.
4. For AC or DC Circuits, whether it is an Overhead or Underground Circuit.
5. Whether the Non-Automatic Outage is a Planned Outage or an Operational Outage.
6. The Outage Cause Code. Three codes are provided for Planned Outages and four codes are provided for Operational Outages.
7. The Outage Start Time. The date (mm/dd/yyyy) and time (hh:mm), rounded to the minute, that the Automatic Outage of an Element started. Outage Start Time is expressed in Coordinated Universal Time (UTC), not local time.
8. The Outage Duration, rounded to the nearest minute.
9. An Outage Continuation Flag which indicates whether the outage continues into the next reporting year or started in the prior year.

Figure 2 shows the Non-Automatic Outage data required for an AC Circuit compared to the same form for an Automatic Outage. The column structure has been kept the same, with unutilized Automatic Outage columns labeled "NA." While less data per outage is required for a Non-Automatic Outage compared to an Automatic Outage, the number of Non-Automatic Outages is expected to be significantly greater than the number of Automatic Outages.

Figure 2

AC Circuit Automatic Outage Data

AC Circuit Momentary and Sustained Outage Data																
			Circuit Substation Boundaries										Cause Codes			
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
Outage ID Code	Event ID Code [2]	Voltage Class	AC Substation Name #1	AC Substation Name #2	AC Substation Name #3	TO Element Identifier (AC Circuit)	OH or UG?	AC Multi-Owner Com. Struct. Flag [3]	Fault Type	Outage Initiation Code	Start Time (mm/dd/yyyy hh:mm) (UTC) [4]	Outage Duration hhhh:mm [5]	Initiating Cause Code [6]	Sustained Cause Code [7]	Outage Mode	Outage Continuation Code [8]
100	A-2008	200-299 kV	Brown	Smith		BwSh#1	OH	0	No fault	AC Substation-Initiated	5/5/2008 13:04	1:20	Lightning	Failed Protection System Equipment	Dependent Mode Initiating	0

AC Circuit Non-Automatic Outage Data

AC Circuit Planned and Operational Outage Data																
			Circuit Substation Boundaries													
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
Outage ID Code	NA	Voltage Class	AC Substation Name #1	AC Substation Name #2	AC Substation Name #3	TO Element Identifier (AC Circuit)	OH or UG?	NA	NA	Non-Automatic Outage Type	Start Time (mm/dd/yyyy hh:mm) (UTC) [3]	Outage Duration hhhh:mm [4]	Planned Outage Cause Code [5]	Operational Cause Code [6]	NA	Outage Continuation Code [7]
200	NA	200-299 kV	Brown	Smith		BwSh#1	OH	NA	NA	Planned	10/5/2008 15:08	21:20	Maintenance & Construction	NA	NA	0

4. Phase II Metrics

The *Transmission Availability Data System Revised Final Report* dated September 26, 2007 describes a set of Phase I metrics in Section 4 of the report and in a table in Appendix 4. Phase II metrics will build on the Phase I metrics, and because almost all Element outages are being recorded, the calculation of the Mean Time Between Sustained Outages, or mean "Up Time" (also referred to as Mean Time Between Failure) and Availability Percentage will now be more accurate.[18]

As we stated in Section 4 of the Phase I report dated September 26, 2007:

> "We have not established a comprehensive set of uniform metric calculations since we expect that it will take some work with the data itself to tell us which combinations provide meaningful information."

This same principle applies to the Phase II TADS metrics recommended below - they are a starting point.

The common metrics listed below will be reported to describe the performance of each Element for the reporting year. When possible, the standard deviation of metrics will be calculated and statistical confidence intervals reported. Similar metrics can be developed for each subcategory or combination of cause codes.

1. Non-Automatic Outage frequency per Element (Planned, Operational, and total).
2. For Planned and Operational Outages:
    i. Outage Duration per Element
    ii. Mean Element outage time
    iii. Median Element outage time
3. Percent of Elements with zero Non-Automatic Outages.[19]
4. The maximum percentage of simultaneous Element Outages. Since TADS will have almost all outage data including outage start time and duration, we will be able to calculate the maximum percentage of simultaneous outages that occurred for an Element on a Transmission Owner or Regional Entity basis. This could be refined and sub-divided by voltage class. For example, if a TO has 25 AC Circuits in the 200-299 kV, this metric would display the maximum percentage that were out simultaneously. The associated simultaneous outage time could also be displayed. With complete historic outage data, we could map the historic unavailability of a set of Elements or of all Elements. TOs and regions could compare outages to historic load

[18] Although outages that qualify for the 30-minute exclusion of Planned Outages will not be recorded, these are expected to be minimal in total duration.

[19] Each TO will provide the number of Elements without an outage, with NERC calculating the percentage. While TADS requires the number of Elements to be reported, the TO-provided information is required because TADS does not require an Element list that provides each Element with a unique descriptor.

levels. Transmission Planners will be able to evaluate assumptions used in modeling the power system for planning purposes.

The basic set of Phase II TADS metrics are shown on the Table 1 (next two pages), along with the two updated metrics from Phase I.

- For Mean Time to Repair in Phase I, we are calculating a standard deviation and a confidence interval for Phase I data, and will do so for the Mean Element Planned Outage Time and Mean Element Operational Outage Time in Phase II data. We also believe that the median times add perspective to the mean times since one can easily tell if a few events affected the mean by comparing the two.

Some TOs may want to develop metrics that combine Automatic Outage data with Non-Automatic Outage data. For example, the EIA's term for "unscheduled outages" in Figure 1 combines Automatic Outage Data with Operational Outages having an Emergency Outage Cause Code. Some TOs might consider this data to be the basis of a "forced outage rate" calculation, while others may consider different parameters in the term "forced outage rate." We will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric.

Finally, Phase II metrics should not be the sole driver of actual maintenance practices. Maintenance practices should be based upon reliability considerations and good utility practice.

Table 1: TADS Phase II Metrics and Updated Phase I Metrics

No.	Metric	Formula	Units	Acronymn
	Element Outage Frequency			
1	Element Total Non-Automatic Outage Frequency	Total Non-Automatic Outages / Total Elements	No. Non-Automatic Outages per Element per year	TNAOF
2	Element Planned Outage Frequency	Total Planned Outages / Total Elements	No. Planned Outages per Element per year	POF
3	Element Operational Outage Frequency	Total Operational Outages / Total Elements	No. Operational Outages per Element per year	OOF
	Element Outage Duration and Outage Time			
4	Element Total Non-Automatic Outage Duration Time	Total Non-Automatic Outage Hours / Total Elements	Average no. of Non-Automatic Outage hours per Element per year	TNAODT
5	Mean Total Non-Automatic Outage Time	Total Non-Automatic Outage Hours / Total Non-Automatic Element Outages	Average no. of Non-Automatic Outage Hours per outaged Element per year	TNAMPOT
6	Median Total Non-Automatic Outage Time	The time when 50% of the Mean Total Non-Automatic Outage Time minutes are greater than	Median no. of Non-Automatic Outage Hours per outaged Element	TNAMdPOT
7	Element Planned Outage Duration Time	Total Planned Outage Hours / Total Elements	Average no. of Planned Outages hours per Element per year	PODT
8	Mean Element Planned Outage Time	Total Planned Outage Hours / Total Planned Element Outages	Average no. of Planned Outage Hours per outaged Element per year	MPOT
9	Median Element Planned Outage Time	The time when 50% of the Mean Planned Outage Time minutes are greater than this figure	Median no. of Planned Outage Hours per outaged Element	MdPOT
10	Element Operational Outage Duration Time	Total Operational Outage Hours / Total Elements	Average no. of Operational Outages hours per Element per year	OODT
11	Mean Element Operational Outage Time	Total Operational Outage Hours / Total Operational Element Outages	Average no. of Operational Outage Hours per outaged Element per year	MOOT
12	Median Element Opertional Outage Time	The time when 50% of the Mean Operational Outage Time minutes are greater than this figure	Median no. of Operational Outage Hours per outaged Element	MdOOT

Table 1: TADS Phase II Metrics and Updated Phase I Metrics (cont'd)

	Element Availability			
12	Percentage of Elements with Zero Non-Automatic Outages	Total Elements with Zero Non-Automatic Outages / Total Elements	Percentage	PCNAZO
13	Maximum Percent of Simultaneous Element Outages	This will be calculated by taking all Element outages and searching for the time when the maximum no. are out due to Sustained Automatic Outages and Non-Automatic Outages.	Percentage	MSIM
	Phase I Revised Metrics with Phase II Outage Data			
Phase I	Mean Time Between Sustained Element Outages (Mean "Up Time"). Also referred to as Mean Time Between Failures.	(Total Element Hours - Total Sustained Outage Hours) / Total Sustained Element Outages	Mean (average) no. of hours of operation of an Element before it fails	MTBF[1]
Updated w. Phase II	Mean Time Between Sustained Element Outages (Mean "Up Time"). Also referred to as Mean Time Between Failures.	(Total Element Hours - Total Sustained Outage Hours - Total Non-Automatic Outage Hours) / Total Sustained Element Outages	Mean (average) no. of hours of operation of an Element before it fails	MTBF
Phase I	Element Availability Percentage	1- (Total Sustained Outage Hours / Total Element Hours) * 100	Percentage	APC[1]
Updated w. Phase II	Element Availability Percentage	1- [(Total Sustained Outage Hours + Total Non-Automatic Outage Hours) / Total Element Hours] * 100	Percentage	APC

[1]These Phase I metrics are from Appendix 4 of the *Transmission Availability Data System Revised Final Report* dated September 26, 2007.

5. Additional Phase II Recommendations

5.1. NERC Review of TADS Submittals by TOs

In the Phase I report, we noted that the Regional Entities will be spot checking TO-submitted TADS data for potential errors. We will be conducting workshops to discuss data collection and interpretation practices with the goal of ensuring both accuracy and consistency of TADS data submitted by TOs.

We are now proposing to conduct data validation reviews of TADS data submissions for Automatic and Non-Automatic Outages with the submitting Transmission Owners. These reviews would cover the Transmission Owner's most recent TADS data submittal and evaluate the TO's process for collecting and validating its TADS data. This review has the single objective of improving the quality of TADS data. Eventually all TOs would be reviewed. The results of these reviews will only be shared with the TO that was reviewed. Reviews will not be made public.

To the extent that a review indicates systematic data entry errors, data entries for previous years may need to be revised. We will limit the period for historic corrections to five (5) years. Therefore, TOs would need to maintain historical supporting information used to develop its TADS data for a five-year period.[20] For example, suppose a TO submits 2008 TADS data by March 1, 2009. The TO would need to maintain the supporting information it used to develop its 2008 TADS data until March 1, 2013. This would allow data to be corrected for the five previous years: 2008–2012.

5.2. Phase II Demonstration of Benefits

Many commenters expressed concern as to whether the collection of Phase II TADS data is a benefit to NERC. **We recommend that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion**. **We also recommend that the benefits to NERC of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan. Furthermore, we recommend that this demonstration be followed by re-approval of Phase II by the Planning Committee and the Board of Trustees for Phase II data collection to be continued.** The five-year data collection period will conclude with 2014 data, which will be collected in 2015. The demonstration of Phase II benefits should be performed on or before August 15, 2015 to allow sufficient time for Planning Committee and Board of Trustees action.

5.3. Future Role of the TADSTF

A "task force" under NERC's parlance is a subgroup that is formed to address a specific issue. When that issue has been addressed, a task force is typically dissolved. However,

[20] We will not require TOs to maintain any supporting information for outages that are not reported such as Planned Outages that are covered under the 30-minute exclusion criterion.

Appendix 1. NERC Correspondence to OMB re: Schedule 7

NERC's letter to the Office of Management and Budget follows.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

David R. Nevius
Senior Vice President
Director of Reliability Assessment &
Performance Analysis

October 24, 2007

OMB Desk Officer for DOE ***sent via e-mail to Nathan_J._Frey@omb.eop.gov***
Office of Information and Regulatory Affairs
726 Jackson Place, NW
Washington, DC 20503

Dear Sir or Madam:

NERC Comments on Form EIA-411

In response to the Energy Information Administration's (EIA's) Federal Register notice on September 28, 2007, page no. 55193, the North American Electric Reliability Corporation (NERC) submits these comments to the Office of Management and Budget (OMB) regarding Form EIA-411, "Coordinated Bulk Power Supply Program Report," as proposed by EIA for a three-year extension.

NERC was certified as the Electric Reliability Organization by the Federal Energy Regulatory Commission (FERC or Commission) on July 20, 2006. NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by FERC and governmental authorities in Canada. Within the U.S., NERC has specific statutory authority to request information from owners, users, and operators of the bulk power system. FERC's regulations, at 18 C.F.R. Section 39.2(d) (2007), states:

> "Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity."

With the exception of Schedule 7 as proposed in EIA-411, NERC does not oppose the EIA's proposed *new* mandatory reporting requirements.

However, NERC strenuously objects to EIA's proposal to make Schedule 7 a mandatory requirement going forward. Schedule 7 asks for the same historic transmission outage data that was voluntarily requested in current Form EIA-411 Schedule 7. The provision of such information should either be eliminated or remain voluntary as it has been in the past for the following reasons:

1. The transmission outage data requested on Schedule 7 is inadequate, and, therefore, of no value to the industry.[1] For this reason, NERC undertook the development of its own transmission outage data collection effort. **On October 23, 2007, NERC's Board of Trustees authorized the mandatory collection of transmission outage data from all North American transmission owners (approximately 300), starting with automatic outage data in 2008.** This new data collection initiative, referred to as Phase I Transmission Availability Data System (TADS), took a year to develop, during which time NERC kept EIA staff closely informed. For automatic outages, Phase I TADS will collect more detailed, and, therefore, more useful data for NERC, its members, and government users such as EIA who may access TADS data under NERC's policies. The scope of TADS is described in the *Transmission Availability Data System Revised Final Report* dated September 26, 2007. A second document, *TADS Data Reporting Instruction Manual* dated October 17, 2007, contains instructions for reporting TADS data to NERC. The manual contains instructions for twelve TADS data input forms, and several forms are due in December 2007. The report, manual, and data input forms may be downloaded at http://www.nerc.com/~filez/tadstf.html.
2. Making Schedule 7 mandatory will require U.S. transmission owners to report 2007 calendar year data. This will impose a burden on many owners since they were not notified of the mandatory collection requirement *before* 2007. As a result, they will have to manually construct the requested data from historic outage records. Because the Schedule 7 data itself is inadequate for industry use, OMB approval of mandatory Schedule 7 data collection is tantamount to approving a "make work" data collection effort. That effort will also divert resources needed to implement Phase I TADS.
3. As described in the Section 2.3 of the September 26, 2007 report, NERC has kept EIA apprised of its efforts to develop TADS. NERC is implementing TADS in two phases:
   a. Phase I will require transmission owners to report automatic outage data beginning in calendar year 2008.
   b. Phase II will add planned outage and manual unscheduled outage data in calendar year 2009. Phase II design is underway, and its implementation will be subject to normal NERC approvals.
4. NERC has the expertise and the authority to collect the transmission outage data needed by the U.S. electric industry and is willing to make such information available to the Federal government. The TADS data collection effort will exceed, in both quality and quantity, the information requested in Schedule 7 of the Form EIA-411. Once the TADS data base is populated with the data NERC is requiring to be reported, the data reported under Schedule 7 will be totally unnecessary.

---

[1] In its *Supporting Statement for Electric Power Surveys, OMB Number 1905-0129*, EIA states (on p. 6) that the data in Schedule 7 is used by EIA "to monitor reliability planning, track changes in outage rates, and determine issues affecting transmission outages." Despite this claim, the limited Schedule 7 data cannot meet the uses described by EIA. As an example, EIA data cannot determine "outage rates" because the number of transmission facilities is not requested on Schedule 7.

Therefore, NERC requests that OMB direct EIA either to eliminate Schedule 7 from Form EIA-411 *or* make Schedule 7 voluntary. By either action, OMB will avoid a duplicative, unnecessary, and burdensome data collection effort.

Respectively submitted,

David R. Nevius

cc: Ms. Grace Sutherland, EIA's Statistics and Methods Group, by e-mail to grace.sutherland@eia.doe.gov

Appendix 2. TADS Definitions

The Phase II definitions added in Appendix 2 are highlighted in yellow. Only one change was made to Appendix 2 from the April 4 version of the definitions in the preliminary Phase II report: an example was added to Planned Outage Cause Codes (Section G) based upon comments received.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Availability Data System (TADS) DEFINITIONS

September 11, 2008

to ensure
the reliability of the
bulk power system

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A. TADS Population Definitions

1. Element

The following are Elements for which TADS data are to be collected:

1. AC Circuits ≥ 200 kV (Overhead and Underground)
2. Transformers with ≥ 200 kV low-side voltage
3. AC/DC Back-to-Back Converters with ≥ 200 kV AC voltage, both sides
4. DC Circuits with ≥ +/-200 kV DC voltage

An Element may also be referred to as a "TADS Element" in the Manual. They have the same meaning.

2. Protection System

Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.[1]

3. AC Circuit

A set of AC overhead or underground three-phase conductors that are bound by AC Substations. Radial circuits are AC Circuits.

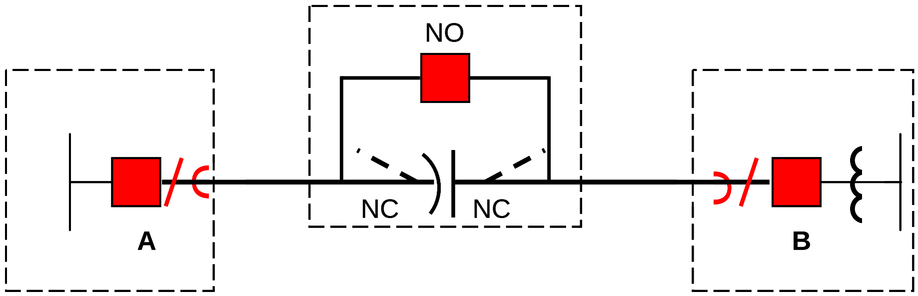
The boundary of an AC Circuit extends to the transmission side of an AC Substation. A circuit breaker, Transformer, and their associated disconnect switches are not considered part of the AC Circuit but instead are defined as part of the AC Substation. The AC Circuit includes the conductor, transmission structure, joints and dead-ends, insulators, ground wire, and other hardware, including in-line switches. The AC Circuit includes in-line switches used to sectionalize portions of the AC Circuit as well as series compensation (capacitors and reactors) that is within the boundaries of the AC Circuit even if these 'in-line' devices are within an AC Substation. If these devices are not within the AC Circuit boundaries, they are not part of the AC Circuit but instead are part of the AC Substation. The diagrams on the next several pages explain this concept. The red arcs define the AC Circuit boundaries.[2]

In Figure 1 (next page), the series capacitor, bypass circuit breaker, and numerous disconnect switches are in a fenced AC Substation that is within the boundaries of the AC Circuit itself. When the series capacitor is connected and the bypass breaker is open, the capacitor and its disconnect switches are part of the AC Circuit. When the bypass breaker is closed, the bypass breaker and its disconnect switches (not shown) are part of the AC Circuit.

[1] This definition is in the current NERC *Glossary of Terms Used in Reliability Standards*.
[2] To simplify future diagrams, disconnect switches may not be shown.

Figure 1

Two in-line NC switches and one series capacitor are part of the AC Circuit between AC Substations A and B. When the bypass breaker and its disconnect switches (not shown) are closed and the capacitor switches opened, the breaker and its switches are part of the AC Circuit.



In Figure 2, the series reactor and in-line switches are part of the AC Circuit since they are within the AC Circuit boundaries even though they are within the AC Substation boundaries. In Figure 3, they are not part of the AC Circuit because they are not within the AC Circuit boundaries.

Figure 2

Two in-line NC switch and one series reactor are part of the AC Circuit between AC Substations A and B. The AC Circuit boundaries are the breaker disconnect switch in AC Substation A and the high-side disconnect switch on the Transformer in AC Substation B.

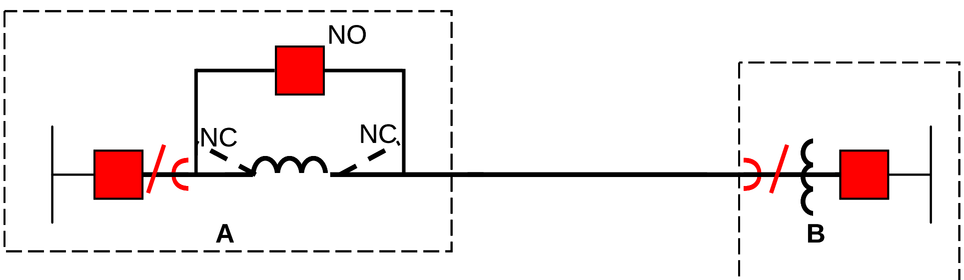
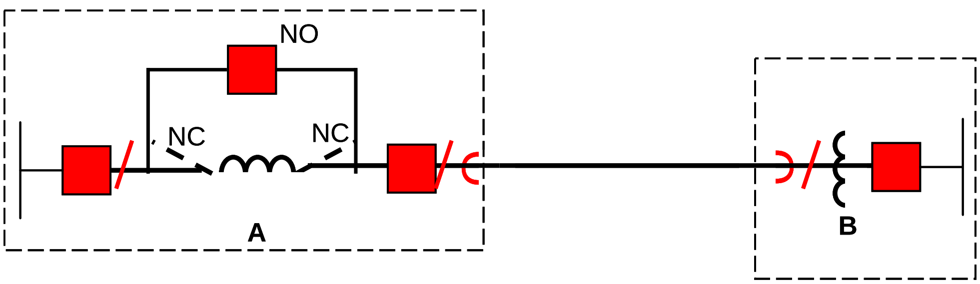


Figure 3

Two in-line NC switches and one series reactor are part of the AC Substation and not part of the AC Circuit between AC Substations A and B



4. Transformer

A bank comprised of three single-phase transformers or a single three-phase transformer. A Transformer is bounded by its associated switching or interrupting devices.

5. AC Substation

An AC Substation includes the circuit breakers and disconnect switches which define the boundaries of an AC Circuit, as well as other facilities such as surge arrestors, buses, Transformers, wave traps, motorized devices, grounding switches, and shunt capacitors and reactors. Series compensation (capacitors and reactors) is part of the AC Substation if it is not part of the AC Circuit. See the explanation in the definition of "AC Circuit." Protection System equipment is excluded.

6. AC/DC Terminal

A terminal that includes all AC and DC equipment needed for DC operation such as PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors and DC filters. On the AC side, an AC/DC Terminal is normally bound by AC breakers at the AC Substation bus where it is connected. On the DC side, it is bound by DC converters and filters. Protection System equipment is excluded.

7. AC/DC Back-to-Back Converter

Two AC/DC Terminals in the same location with a DC bus between them. The boundaries are the AC breakers on each side.

8. DC Circuit

One pole of an Overhead or Underground DC line which is bound by an AC/DC Terminal on each end.

9. Overhead Circuit

An AC or DC Circuit that is not an Underground Circuit. A cable conductor AC or DC Circuit inside a conduit which is *not* below the surface is an Overhead Circuit. A circuit that is part Overhead and part Underground is to be classified based upon the majority characteristic (Overhead Circuit or Underground Circuit) using Circuit Miles.

10. Underground Circuit

An AC or DC Circuit that is below the surface, either below ground or below water. A circuit that is part Overhead Circuit and part Underground Circuit is to be classified based upon the majority characteristic (Overhead Circuit or Underground Circuit) using Circuit Miles.

11. Circuit Mile

One mile of either a set of AC three-phase conductors in an Overhead or Underground AC Circuit, or one pole of a DC Circuit. A one mile-long, AC Circuit tower line that carries two three-phase circuits (i.e., a double-circuit tower line) would equate to two Circuit Miles. A one mile-long, DC tower line that carries two DC poles would equate to two Circuit Miles. Also, a one mile-long, common-trenched, double-AC Circuit Underground duct bank that carries two three-phase circuits would equate to two Circuit Miles.

12. Multi-Circuit Structure Mile

A one-mile linear distance of sequential structures carrying multiple Overhead AC or DC Circuits. (Note: this definition is *not* the same as the industry term "structure mile." A Transmission Owner's Multi-Circuit Structure Miles will generally be less than its structure miles since not all structures contain multiple circuits.)

If a line section contains two or more Multi-Circuit Structures which form one or more multi-circuit spans, the total span length can be measured and the associated mileage should be reported in the 'Multi-Circuit Structure Mile' total inventory. If multiple circuits are connected to only one common structure, that structure should be ignored for outage and inventory mileage purposes.

13. Voltage Class

The following voltages classes will be used for reporting purposes:

1. 200 – 299 kV
2. 300 – 399 kV
3. 400 – 499 kV
4. 500 – 599 kV
5. 600 – 799 kV

For Transformers, the Voltage Class reported will be the high-side voltage, even though the cut-off voltage used in the definition is referenced on the low-side. Voltages are operating voltages.

B. Outage Reporting Definitions

1. Automatic Outage

An outage which results from the automatic operation of switching device, causing an Element to change from an In-Service State to a not In-Service State. A successful AC single-pole (phase) reclosing event is not an Automatic Outage.

2. Momentary Outage

An Automatic Outage with an Outage Duration less than one (1) minute. If the circuit recloses and trips again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered as two outages.

3. Sustained Outage[3]

An Automatic Outage with an Outage Duration of a minute or greater.

[3] The TADS definition of Sustained Outage is different that the NERC *Glossary of Term Used in Reliability Standards* definition of Sustained Outage which is presently only used in FAC-003-1. The glossary defines a Sustained Outage as follows: "The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." The definition is inadequate for TADS reporting for two reasons. First, it has no time limit that would distinguish a Sustained Outage from a Momentary Outage. Second, for a circuit with no automatic reclosing, the outage would not be "counted" if the TO has a successful manual reclosing under the glossary definition.

4. Non-Automatic Outage

An outage which results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

5. Planned Outage

A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation or restoration of an outage of another TADS Element are not reportable.

6. Operational Outage

A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

7. AC Multi-Owner Common Structure Flag

This flag identifies whether the outaged AC Circuit is on common structures with another circuit that is owned by a different Transmission Owner. This flag does not apply to DC Circuits which by default are all assumed to be on common structures with the circuits owned by the same Transmission Owner.

Flag	Flag Interpretation
0	Not applicable. The circuit is not on common structures with another circuit, or the circuit is on common structures, but all circuits are reported by the same Transmission Owner. No analysis of the Event ID Code or the Event Type Number is required by the Regional Entity.
1	Circuit is on common structures with another circuit that is being reported by a different Transmission Owner. The Regional Entity will need to examine Outage Start Times with this same flag to determine whether a second circuit had an outage with nearly the same Outage Start Time, and if so, whether the TOs properly coordinated their Event ID Codes and Event Type Numbers.

8. In-Service State

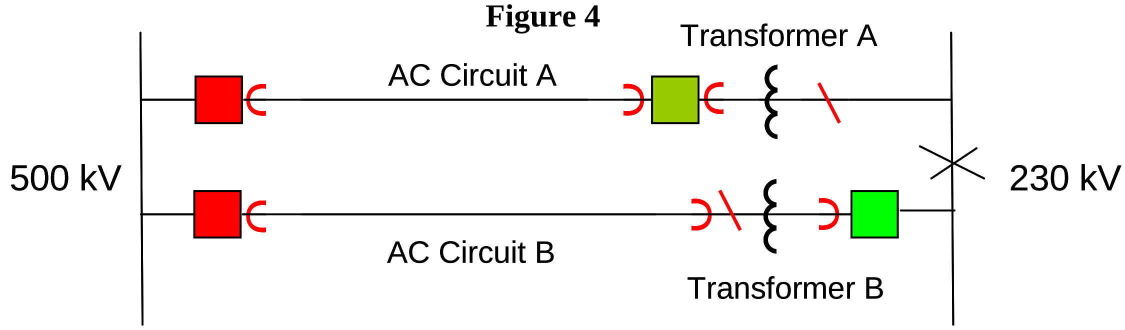
An Element that is energized and fully connected to the system. Examples of reportable AC Circuit and Transformer Automatic Outages are illustrated below. Non-Automatic Outage examples are in Appendix 10.

In Figure 4, AC Circuit A is bound by the disconnect switches (not shown)[4] of two breakers, and Transformer A is bound by a breaker and a disconnect switch. AC Circuit B is bound by a breaker and a disconnect switch, and Transformer B is bound by a breaker and a disconnect switch. 230 kV bus fault opens the green breakers. The TADS Transformers each report an outage. AC Circuit A reports an outage, but AC Circuit B

[4] For simplification, disconnect switches may not be show in some figures. When a circuit breaker or Transformer disconnect switch define an AC Circuit boundary, we may just refer to the circuit breaker and the Transformer as defining the boundary without reference to their disconnect switches.

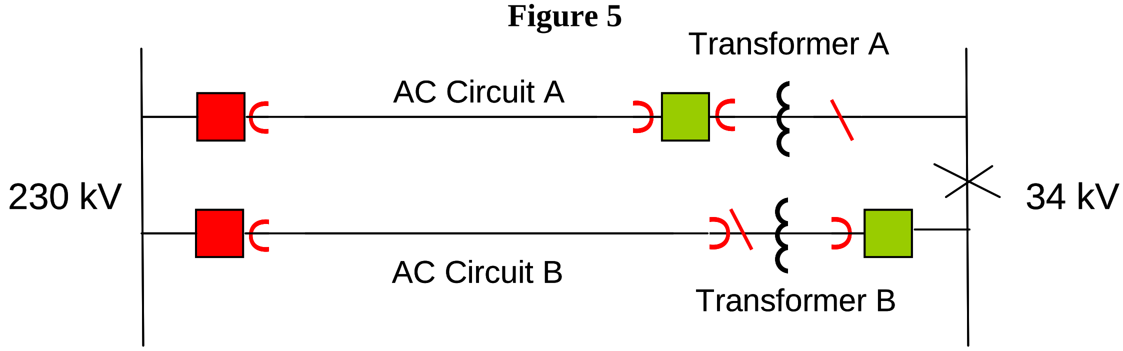
does not. It is defined by the breaker on the left and the disconnect switch on the right. Since the breaker associated with AC Circuit B did not experience and automatic operation, it was not outaged. It remains fully connected by the breaker and the disconnect switch.

Figure 4



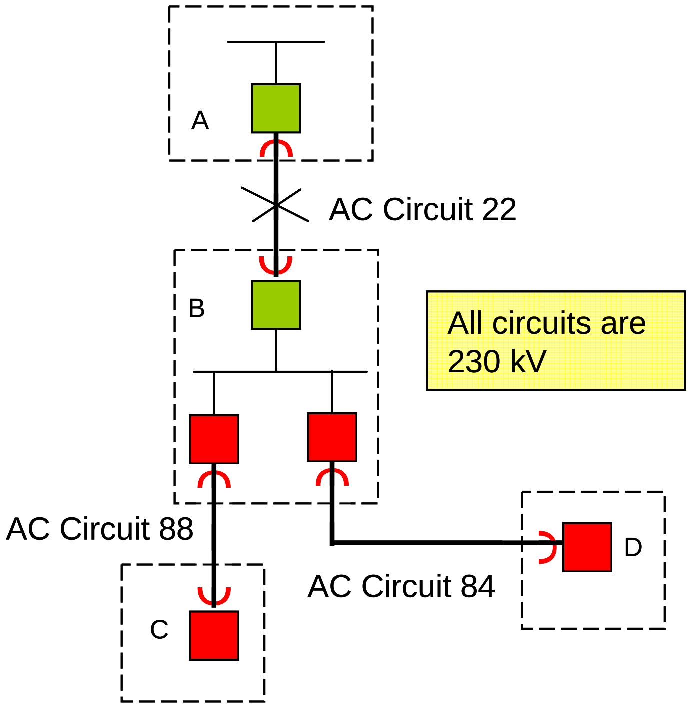
In Figure 5, we have a similar situation, except that the Transformers are not reportable since their low-side voltages are less that 200 kV. The AC Circuit outages are reportable exactly the same as in Figure 4; however, the Transformer outages are not reportable.

Figure 5



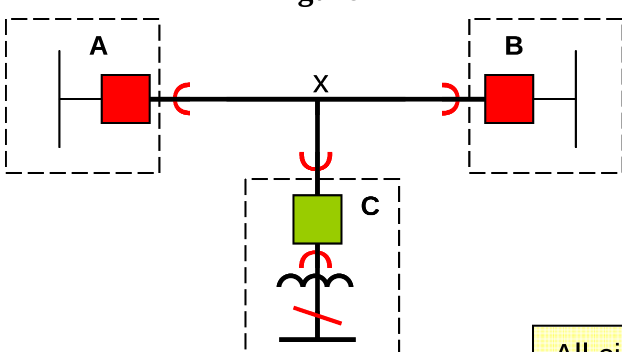
In Figure 6 (next page), AC Circuit 22, the only source connecting AC Substations A and B, has a fault. As a result, AC Circuits 84 and 88 are deenergized but remain fully connected. Three outages are reported: circuits 22, 84, and 88. None of them meet the In-Service State requirement of being energized *and* fully connected.

Figure 6



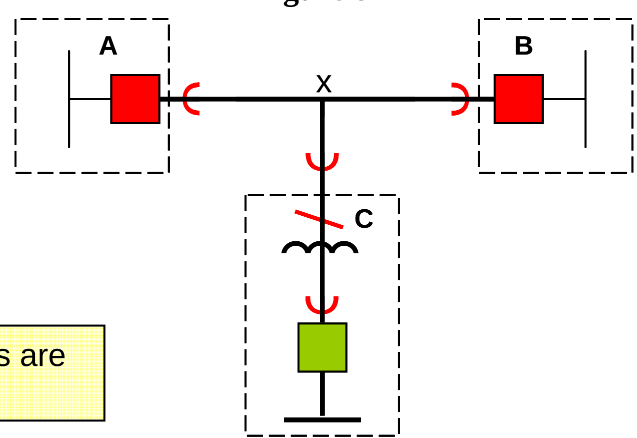
An exception that an Element be "fully connected" to be considered in an In-Service State is provided for a multi-terminal AC Circuit with a Transformer on one terminal that shares a breaker with the circuit.

Figure 7



All circuits are
230 kV

Figure 8



In both figures, the AC Circuit is bounded by AC Substations "A," "B," and "C" as indicated by the red arcs. Each Transformer's boundaries are the red disconnect switch and the red arc before the breaker. Note that the Transformer in either figure may *or* may not be a reportable Element (i.e., one with a low-side voltage ≥ 200 kV).

Assume that each Transformer is out of service as a result of the operation of its associated breaker (indicated in green). In Figure 7, the AC Circuit would normally be considered out of service since the breaker at AC Substation C, which is shared by the AC Circuit and the Transformer, is open. Nevertheless, if all other portions of the AC Circuit are in service, the entire AC Circuit is considered to be in an In-Service State even if the Transformer is out of service. Because TADS does not recognize partial outage states, the multi-terminal exception above was developed so as to not overstate the outage contribution of a multi-terminal configuration of this type. In Figure 8, the open breaker is not shared by the AC Circuit, and the AC Circuit remains fully connected. Thus, the exception does not apply in this case since the AC Circuit is fully connected even though the Transformer out of service.

9. Substation, Terminal, or Converter Name

For Automatic Outages or Non-Automatic Outages of AC Circuits and DC Circuits, the termination name at each end of the circuit will be reported to help identify *where* the circuit is located. For AC Circuits, these are the AC Substation Names; for DC Circuits, these are the AC/DC Terminal Names. For AC/DC Back-to-Back Converters, this is the Converter Station Name.

10. TO Element Identifier

An alphanumeric name that the TO must enter to identify the Element which is outaged (e.g., a circuit name.)

11. Outage Start Time

The date (mm/dd/yyyy) and time (hhhh:mm), rounded to the minute, that the Automatic Outage or Non-Automatic Outage of an Element started. Outage Start Time is expressed in Coordinated Universal Time (UTC), not local time. TADS data is reported on a calendar-year basis, and the TADS Data Reporting Instruction Manual addresses the recording of the Outage Start time of a Sustained Outage that starts in one reporting year and concludes in another reporting year.

12. Outage Duration

The amount of time from the Outage Start Time to when the Element is fully restored to its original or to normal configuration, including equipment replacement. Outage Duration is expressed as hours and minutes, rounded to the nearest minute. Momentary Outages are assigned a time of zero Outage Duration. TADS data is reported on a calendar-year basis, and the TADS Data Reporting Instruction Manual addresses the recording of the Outage Durations of an outage that starts in one reporting year and concludes in another reporting year.

13. Outage Continuation Flag

Not all outages start and end in the same reporting year. This flag describes that characteristic for an outage.

Flag	Flag Interpretation
0	Outage began and ended within the reporting year
1	Outage began in the reporting year but continues into the next reporting year.
2	Outage started in another (previous) reporting year.

14. Outage Identification (ID) Code

A unique alphanumeric identifier assigned by the Transmission Owner to identify the reported outage of an Element.

15. Event

An Event is a transmission incident that results in the Automatic Outage (Sustained or Momentary) of one or more Elements.

16. Event Identification (ID) Code

A unique alphanumeric identifier assigned by the Transmission Owner to an Event. Because outages that begin in one reporting year and end in the next reporting year must have the same Event ID Code, the code must have the reporting year appended to it to ensure its uniqueness. For example, an Event ID Code may be W324-2008. This unique Event ID Code establishes an easy way to identify which Automatic Outages are related to one another as defined by their Outage Mode Codes (see Section D).

1. An Event associated with a Single Mode Outage will have just one Event ID Code.
2. Each outage in a related set of two or more outages (e.g., Dependent Mode, Dependent Mode Initiating, Common Mode, or Common Mode Initiating) shall be given the same Event ID Code.

17. Event Type Number

A code that describes the type of Automatic Outage. The following Event Type Numbers will be used initially:

Event Type No.	Table 1 Category from the TPL Standards	Description
10	B	Automatic Outage of an AC Circuit or Transformer with Normal Clearing.
20	B	Automatic Outage of a DC Circuit with Normal Clearing.
30	C	Automatic Outage of two ADJACENT AC Circuits on common structures with Normal Clearing.
40	C	Automatic Outage of two ADJACENT DC Circuits on common structures with Normal Clearing.
50	NA	Other - please describe the event (optional)

To qualify for an Event Type No. 30 or 40, the outages must be a <u>direct</u> result of the circuits occupying common structures. These characteristics will generally apply.

1. The Outage Initiation Codes are either Element-Initiated or Other-Element Initiated.
2. The Outage Mode Codes are one of the following: (a) Dependent Mode Initiating (one outage) and Dependent Mode (second outage); (b) Common Mode Initiating and Common Mode (two outages); or (c) both Common Mode (two outages).

<u>Event Type No. 30 and 50 Examples</u>

These are examples of Events that are Event Type No. 30:

1. A tornado outages two circuits on common structures. In this example, the outage is Element-Initiated and Common Mode. This is an Event Type No. 30 because the loss of both circuits was directly related to them being on the same structures.

2. On one circuit, a conductor breaks (outaging the circuit), and the conductor swings into a second circuit on common structures. The first circuit outage is Element-Initiated and Dependent Mode Initiating; the second circuit outage is Other-Element Initiated and Dependent Mode. This is an Event Type No. 30 because the second circuit's outage was a result of it being on common structures as the first circuit.

These Events are not an Event Type No. 30; instead, they are an Event Type No. 50.

1. Two AC Circuits on common structures are outaged due to a bus fault in the AC Substation where the circuits terminate. Both outages are Substation-Initiated and Common Mode. Because the outages are not a result of the two circuits being on common structures, it is not an Event Type No. 30. Therefore, it is an Event Type No. 50.
2. Two AC Circuits are on common structures and terminate at the same bus. Lightning strikes one AC Circuit, but the breaker fails to open due to a failure of a relay to operate properly. The second circuit, which is connected to the same bus, is outaged as a result of the failure of first circuit's breaker to open. The first outage is an Element-Initiated and Dependent Mode Initiating; the second outage is Other Facility-Initiated and Dependent Mode. (Note: the relay is excluded as part of an AC Substation, making the Outage Initiation Code "Other-Facility Initiated" and not "Substation-Initiated.") Because the outages are not a result of the two circuits being on common structures, it is not an Event Type No. 30. Therefore, it is an Event Type No. 50.

18. Fault Type

The descriptor of the fault, if any, associated with each Automatic Outage of an Element. Several choices are possible for each Element outage:

1. No fault
2. Phase-to-phase fault (P-P)
3. Single phase-to-ground fault (P-G)
4. Phase-to-phase-to ground (P-P-G), 3P, or 3P-G fault
5. Unknown fault type

The Fault Type for each Element outage may be determined from recorded relay targets or by other analysis. TOs should use the best available data to determine (1) whether a fault occurred on each outaged Element and, if so, (2) what type of fault occurred. Relay targets should be documented as soon as practical after a fault and the targets re-set to prepare for the next fault. If a single fault results in several Element outages, the protective relay targets associated with each Element indicate the Fault Type for that Outage. Relay targets are not a fool proof method to determine the Fault Type; however, they may be the best available data to determine Fault Type. An Element whose relays did not indicate a fault should be reported as "No fault."

Example: A 500 kV AC Circuit has a single phase-to-ground fault that also results in an Outage of a 500/230 kV Transformer. The AC Circuit outage would have "Single phase-to-ground fault (P-G)" selected as the Fault Type, while the Transformer would have "No fault" selected.

19. Normal Clearing

A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection system.[5]

C. Outage Initiation Codes

The Outage Initiation Codes describe *where* an Automatic Outage was initiated on the power system.

1. Element-Initiated Outage

An Automatic Outage of an Element that is initiated on or within the Element that is outaged.

2. Other Element-Initiated Outage

An Automatic Outage of an Element that is initiated by another Element and not by the Element that is outaged.

3. AC Substation-Initiated Outage

An Automatic Outage of an Element that is initiated on or within AC Substation facilities.

4. AC/DC Terminal-Initiated Outage

An Automatic Outage of an Element that is initiated on or within AC/DC Terminal facilities.

5. Other Facility-Initiated Outage

An Automatic Outage that is initiated on or within other facilities. "Other facilities" include any facilities not includable in any other Outage Initiation Code. (Note: An Automatic Outage initiated on a Transformer that is *not* an Element is considered an AC Substation or an AC/DC Terminal-Initiated Outage since the Transformer would be considered part of an AC Substation or AC/DC Terminal.)

<u>Outage Initiation Code Examples</u>

1. A Transformer which is an Element is outaged. Is its outage an Element-Initiated Outage or a Substation-Initiated Outage? It depends. If the outage initiated on or within the Element (e.g., an internal fault or a cracked insulator that caused a fault), the outage is Element-Initiated, even though the Transformer is in a Substation. However, if the Transformer outage was not due to the Transformer itself but due, for example, to a failed circuit breaker, it is Substation-Initiated.
2. An AC Circuit which is an Element has an outage that was initiated by a non-Element AC Circuit. The Element outage is Other Facility-Initiated.
3. An AC Circuit Outage was initiated by an Element Transformer outage. The AC Circuit Outage is Other Element-Initiated.

[5] This definition is in the current NERC *Glossary of Terms Used in Reliability Standards*.

D. Outage Mode Codes

The Outage Mode Code describes whether an Automatic Outage is related to other Automatic Outages.

1. Single Mode Outage

An Automatic Outage of a single Element which occurred independent of any other outages (if any).

2. Dependent Mode Initiating Outage

An Automatic Outage of a single Element that initiates one or more subsequent Element Automatic Outages.

3. Dependent Mode Outage

An Automatic Outage of an Element which occurred as a result of an initiating outage, whether the initiating outage was an Element outage or a non-Element outage. (Note: to re-emphasize, a Dependent Mode Outage must be a result of another outage.)

4. Common Mode Outage

One of two or more Automatic Outages with the same Initiating Cause Code and where the outages are not consequences of each other and occur nearly simultaneously (i.e., within cycles or seconds of one another).

5. Common Mode Initiating Outage

A Common Mode Outage that initiates one or more subsequent Automatic Outages.

Dependent Mode and Common Mode Outage Examples

1. A Dependent Mode Outage involves two outages, but one of the outages can be a non-Element outage. Therefore, not all Dependent Mode Outages will have an associated Dependent Mode Initiating Outage. If the initiating outage is one of the four defined Elements, that outage will be a Dependent Mode Initiating Outage, and the resulting second Element outage will be a Dependent Mode Outage. For example, suppose a 500 kV AC Circuit is outaged as a result of a 500/230 kV Transformer outage. The AC Circuit outage is a Dependent Mode Outage, and the Transformer outage is a Dependent Mode Initiating Outage. However, if an outage is not initiated by an Element, it will not have an associated Dependent Mode Initiating Outage. If the Transformer in the previous example had been a 345/138 kV Transformer and the AC Circuit a 345 kV circuit, the Transformer would not be an Element and, therefore, the AC Circuit outage would not have an associated Dependent Mode Initiating Outage. The AC Circuit outage would be classified as a Dependent Mode Outage since it was the result of a non-Element outage.
2. A Common Mode Outage involves the two outages, but unlike a Dependent Mode Outage, both outages must be Elements. In addition, one outage must not cause the second outage to occur; i.e., the two outages are not consequences of each other. In addition, they must occur nearly simultaneously. As an example, suppose that lightning strikes two AC Circuits in the same right of way (but not

on a common structure) and both circuits are outaged nearly simultaneously. Assume no further outages occur. Both are Common Mode Outages. Now assume the same scenario with a slight difference: one AC Circuit clears normally, the second AC Circuit does not, and there is a circuit breaker failure, resulting in the outage of a third AC Circuit. The first AC Circuit outage is a Common Mode Outage. The second AC Circuit outage is a Common Mode Initiating Outage, with the third AC Circuit outage a Dependent Mode Outage.

E. Cause Codes Types

1. Initiating Cause Code

The Cause Code that describes the initiating cause of the outage.

2. Sustained Cause Code

The Cause Code that describes the cause that contributed to the longest duration of the outage. Momentary Outages do not have a Sustained Cause Code.

<u>Initiating and Sustained Cause Code Examples</u>

Suppose a lightning strike on an AC Circuit that should have cleared normally becomes a Sustained Outage because of breaker failure. "Lightning" is the Initiating Cause Code and "Failed AC Substation Equipment" is the Sustained Cause Code.

To illustrate the meaning of the phrase "contributed to the longest duration" in the definition above, suppose that lightning caused a conductor to break ("Failed AC Circuit Equipment") and that the breaker for the circuit also failed ("Failed AC Substation Equipment'). This example has two possible Sustained Outage Cause Codes, and the one to select is the one that contributed to the longest duration. If the conductor was repaired before the circuit breaker, then "Failed AC Substation Equipment" is the Sustained Cause Code since the circuit breaker outage contributed to the longest duration.

<u>Special Exception for 2008 Reporting:</u> For reporting in 2008, Transmission Owners should supply both the Initiating and Sustained Cause Codes if they have them available. However, if both Cause Codes are not available, at least one Cause Code, either Initiating or Sustained, must be supplied for a Sustained Outage. (Momentary Outages still must have their Initiating Cause Code reported.) As an example, suppose a TO only has the Initiating Outage Cause Code available to it for Sustained Outages. The Initiating Cause Code would be entered for each outage, and the appropriate Sustained Cause Code would be "Unavailable." On the other hand, suppose only a Sustained Cause Code is available. Sustained Outages would then have their Initiating Outage Codes reported as "Unavailable." The "Unavailable" code will be deleted in 2009 when TOs are expected to have both Initiating and Sustained Cause Codes available.

F. Cause Codes

1. Weather, excluding lightning

Automatic Outages caused by weather such as snow, extreme temperature, rain, hail, fog, sleet/ice, wind (including galloping conductor), tornado, microburst, dust storm, and flying debris caused by wind.

2. Lightning

Automatic Outages caused by lightning.

3. Environmental

Automatic Outages caused by environmental conditions such as earth movement (including earthquake, subsidence, earth slide), flood, geomagnetic storm, or avalanche.

4. Contamination

Automatic Outages caused by contamination such as bird droppings, dust, corrosion, salt spray, industrial pollution, smog, or ash.

5. Foreign Interference

Automatic Outages caused by foreign interference from such objects such as an aircraft, machinery, a vehicle, a train, a boat, a balloon, a kite, a bird (including streamers), an animal, flying debris not caused by wind, and falling conductors from one line into another. Foreign Interference is <u>not</u> due to an error by a utility employee or contractor. Categorize these as “Human Error.”

6. Fire

Automatic Outages caused by fire or smoke.

7. Vandalism, Terrorism or Malicious Acts

Automatic Outages caused by intentional activity such as shot conductors or insulators, removing bolts from structures, and bombs.

8. Failed AC Substation Equipment

Automatic Outages caused by the failure of AC Substation; i.e., equipment “inside the substation fence” including Transformers and circuit breakers but excluding Protection System equipment. Refer to the definition of “AC Substation.”

9. Failed AC/DC Terminal Equipment

Automatic Outages caused by the failure of AC/DC Terminal equipment; i.e., equipment “inside the terminal fence” including PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors, and DC filters but excluding Protection System equipment. Refer to the definition of “AC/DC Terminal.”

10. Failed Protection System Equipment

Automatic Outages caused by the failure of Protection System equipment. Includes any relay and/or control misoperations *except* those that are caused by incorrect relay or control settings that do not coordinate with other protective devices. Categorize these as “Human Error”.

11. Failed AC Circuit Equipment

Automatic Outages related to the failure of AC Circuit equipment, i.e., overhead or underground equipment "outside the substation fence." Refer to the definition of "AC Circuit."

12. Failed DC Circuit Equipment

Automatic Outages related to the failure DC Circuit equipment, i.e., overhead or underground equipment "outside the terminal fence." Refer to the definition of "DC Circuit." However, include the failure of a connecting DC bus within an AC/DC Back-to-Back Converter in this category.

13. Vegetation

Automatic Outages (both Momentary and Sustained) caused by vegetation, with the exception of the following exclusions which are contained in FAC-003-1:

1. Vegetation-related outages that result from vegetation falling into lines from outside the right of way that result from natural disasters shall not be considered reportable with the Vegetation Cause Code. Examples of disasters that could create non-reportable Vegetation Cause Code outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods, and
2. Vegetation-related outages due to human or animal activity shall not be considered reportable under the Vegetation Cause Code. Examples of human or animal activity that could cause a non-reportable Vegetation Cause Code outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Outages that fall under the exclusions should be reported under another Cause Code and not the Vegetation Cause Code.

14. Power System Condition

Automatic Outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out of service).

15. Human Error

Automatic Outages caused by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner will be identified and reported in this category. Also, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported in this category.

16. Unknown

Automatic Outages caused by unknown causes should be reported in this category.

17. Other

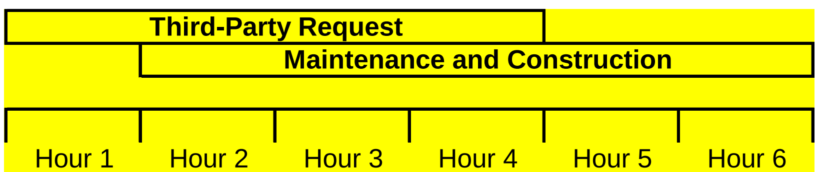
Automatic Outages for which the cause is known; however, the cause is not included in the above list.

18. Unavailable

Use for Sustained Outages for which either the Initiating or Sustained Cause Codes are unavailable to the Transmission Owner. If a Transmission Owner uses this code for Sustained Outages, it should be used on only *one* type of Cause Code (Initiating or Sustained), whichever is unavailable. If during 2008, both Cause Codes become available to the Transmission Owner, stop using "Unavailable." The "Unavailable" code will be withdrawn in 2009.

G. Planned Outage Cause Codes

If a Planned Outage was conducted for two reasons, record the Cause Code that contributed to the longest duration. For example, if an outage is 6 hours in duration and was taken to comply with a third-party request (which took 4 hours) as well as maintenance and construction (which took 5 hours), record the outage as Maintenance and Construction. See the diagram below.



1. Maintenance and Construction

Use for Planned Outages associated with maintenance and construction of electric facilities, including testing. This includes requests from any entity that is defined in the NERC Functional Model.[6]

2. Third-Party Requests

Use for Planned Outages that are taken at the request of a third party such as highway departments, the Coast Guard, etc.

3. Other Planned Outage

Use for Planned Outages for reasons not included in the above list, including human error.

[6] The Functional Model is available at http://www.nerc.com/page.php?cid=2|247|108. As an example, an outage is requested by a Generation Operator for purposes of completing an interconnection of its facilities would be classified in the Maintenance and Construction category. A Load-Serving Entity which requests an outage to make repairs to its substation would also be reported in this category.

H. Operational Outage Cause Codes

1. Emergency

Use for Operational Outages that are taken for the purpose of avoiding risk to human life, damage to equipment, damage to property, or similar threatening consequences.

2. System Voltage Limit Mitigation

Use for Operational Outages taken to maintain the voltage on the transmission system within desired levels (i.e., voltage control).

3. System Operating Limit Mitigation, excluding System Voltage Limit Mitigation

Use for Operational Outages taken to keep the transmission system within System Operating Limits, except for System Voltage Limit Mitigation. The term "System Operating Limit" is defined in the NERC *Glossary of Terms Used in Reliability Standards* and is excerpted below.

> "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:
> 1. Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
> 2. Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
> 3. Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
> 4. System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). "
>
> Do not include actions in the last category (System Voltage Limits) since this is included in the previous "System Voltage Limitation" code.

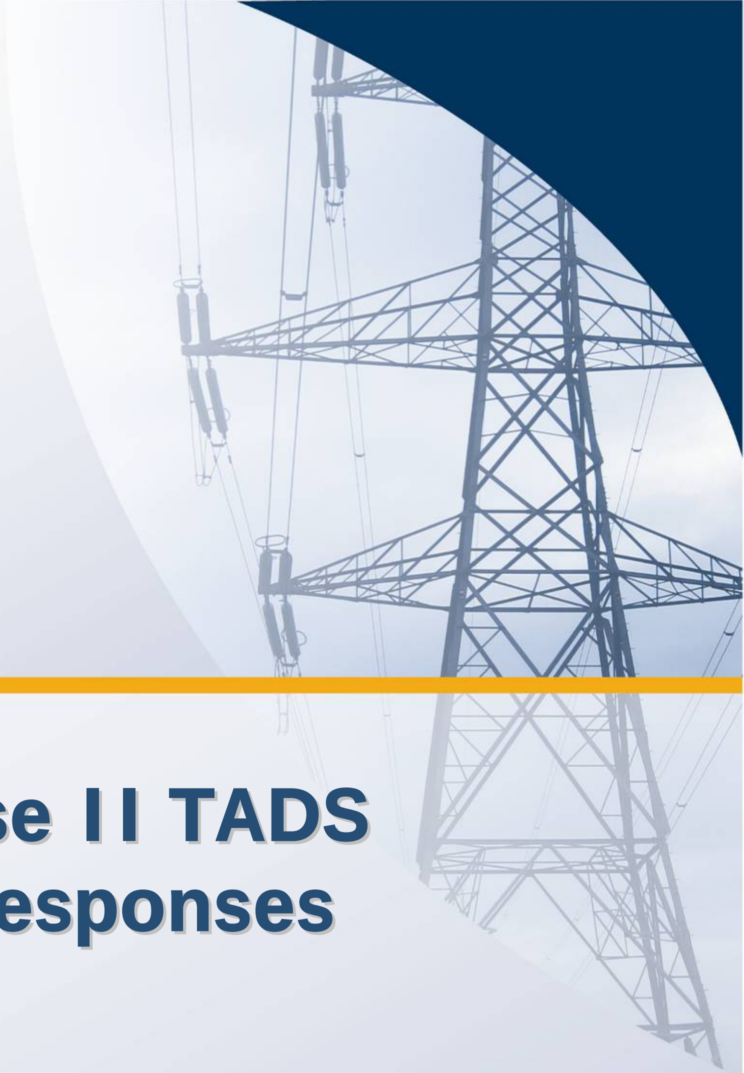
4. Other Operational Outage

Use for Operational Outages for reasons not included in the above list, including human error.

Appendix 3. Summary of Phase II Comments and Responses

Appendix 3, which follows, is a stand-alone report.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Summary of Phase II TADS Comments and Responses

September 11, 2008

to ensure the reliability of the bulk power system

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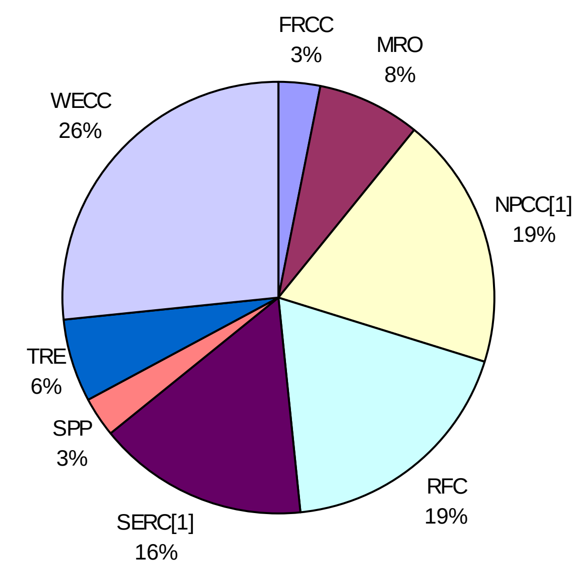
1 Introduction

1.1 Who Commented

The April 30, 2008 letter from Mr. David Nevius of NERC requesting comments on the Phase II preliminary TADS report and Manual resulted in comments from 49 entities – 44 Transmission Owners (TOs) and five other entities. The 44 Transmission Owner responses represented a total of 63 registered NERC Transmission Owners and one unregistered Canadian TO, AltaLink Management, which is voluntarily submitting Phase I TADS data. The identification of the TOs that commented is shown on Table 1 on the next page. The distribution of responding TOs per NERC region is depicted on Figure 1 below. The response rate by region is shown on Table 2.

Figure 1
Distribution of Responding TOs by NERC Region



[1] Includes total registered TOs represented by pseudo NERC IDs for National Grid (NPCC) and Southern Transmission Company (SERC).

The five other entities that provide comments are listed below:

1. The Energy Information Administration (EIA)
2. The Independent Electricity Operator (IESO), which is the Transmission Operator for the Ontario province
3. The National Electrical Manufacturers Association (NEMA)
4. Separate comments came from different Reliability*First* Corporation staff. For this report, their responses will be combined.
5. WECC submitted comments on behalf of their Reliability Subcommittee and their Reliability Performance Evaluation Work Group.

All materials related to the request for comments, including the individual comments, are posted at http://www.nerc.com/filez/tadstf.html.

Table 1
Transmission Owners that Provided Phase II TADS Comments

NERC ID	Company Name	Country	Region
PSD00002	AltaLink Management Ltd. **[1]**	Canada	WECC
NCR00682	American Electric Power Service Corp **[2]**	US	RFC
NCR04006	American Electric Power Service Corp **[2]**	US	TRE
NCR01056	American Electric Power Service Corporation **[2]**	US	SPP
NCR00685	American Transmission Company	US	RFC
NCR05016	Arizona Public Service Company	US	WECC
NCR00688	Atlantic City Electric Company (ACE) **[3]**	US	RFC
NCR00689	Baltimore Gas & Electric Company	US	RFC
NCR05032	Bonneville Power Administration	US	WECC
NCR04028	CenterPoint Energy	US	TRE
NCR00729	Commonwealth Edison Company **[4]**	US	RFC
NCR07044	Connecticut Light & Power **[5]**	US	NPCC
NCR05123	Cowlitz County PUD No. 1	US	WECC
NCR04037	CPS ENERGY	US	TRE
NCR00752	Delmarva Power **[3]**	US	RFC
NCR01214	Dominion Virginia Power - Transmission	US	RFC
NCR01219	Duke Energy Carolinas **[6]**	US	SERC
NCR00761	Duke Energy Corp. **[6]**	US	RFC
NCR10242	Dynegy Arlington Valley, LLC	US	WECC
NCR01234	Entergy	US	SERC
NCR01249	Georgia Transmission Corporation	US	SERC
NCR07109	HydroOne Networks	Canada	NPCC
NCR05191	Idaho Power Company	US	WECC
NCR10192	ITC Midwest **[7]**	US	MRO
NCR00803	ITC Transmission **[7]**	US	RFC
NCR01107	Kansas City Power & Light	US	SPP
NCR01003	Manitoba Hydro	Canada	MRO
PSD00004	National Grid **[8]**	US	NPCC
NCR01018	Nebraska Public Power District	US	MRO
NCR07161	New York Power Authority	US	NPCC
NCR02611	Northern Indiana Public Service Company	US	RFC
NCR07178	Nova Scotia Power Inc.	Canada	NPCC
NCR04109	Oncor Electric Delivery	US	TRE
NCR05299	Pacific Gas and Electric Company	US	WECC
NCR05304	PacifiCorp	US	WECC
NCR08025	PECO Energy **[4]**	US	RFC
NCR00881	Potomac Electric Power Company (PEPCO) **[3]**	US	RFC
NCR00063	Progress Energy - Florida	US	FRCC
NCR01298	Progress Energy Carolinas	US	SERC
NCR07203	Public Service Company of New Hampshire **[5]**	US	NPCC
NCR05368	Sacramento Municipal Utility District	US	WECC
NCR05372	Salt River Project Agricultural Improvement and Power District	US	WECC
NCR05377	San Diego Gas & Electric	US	WECC
PSD00001	Southern Company Transmission **[9]**	US	SERC
NCR05402	Southwest Transmission Cooperative, Inc.	US	WECC
NCR00073	Tallahassee, City of	US	FRCC
NCR01151	Tennessee Valley Authority	US	SERC
NCR10102	Tri-State Generation and Transmission Association, Inc. **[10]**	US	MRO
NCR10030	Tri-State Generation and Transmission Association, Inc. - Reliability **[10]**	US	WECC
NCR05461	Western Area Power Administration - Desert Southwest Region	US	WECC
NCR05464	Western Area Power Administration - Rocky Mountain Region	US	WECC
NCR05465	Western Area Power Administration - Sierra Nevada Region	US	WECC
NCR05467	Western Area Power Administration - Upper Great Plains Region **[11]**	US	WECC
NCR01036	Western Area Power Administration- Upper Great Plains East **[11]**	US	MRO
NCR07232	Western Massachusetts Electric Company **[5]**	US	NPCC

Table 1 (cont'd)
Transmission Owners that Provided Phase II TADS Comments

No.	Table 1 Notes
[1]	AltaLink is not a NERC-registered TO, but it is voluntarily providing Ph I TADS data for Automatic Outages. It was assigned a pseudo NERC ID for TADS. See the Manual, Section 1.9, for a description of pseudo NERC IDs.
[2]	Comments from American Electric Power were attributed to three AEP NERC IDs.
[3]	Comments from Pepco Holdings, Inc. were attributed to three of its affiliates: Atlantic City Electric Company, Delmarva Power, and Potomac Electric Power Company.
[4]	Comments from Exelon were attributed to two affiliates: Commonwealth Edison and PECO Energy.
[5]	Comments from Northeast Utilities were attributed to three of its affiliates: Connecticut Light & Power, Public Service Company of New Hampshire, and Western Massachusetts Electric Company.
[6]	Comments from Duke Energy were attributed to two Duke NERC IDs.
[7]	Comments from ITC Holdings were attributed to two affiliates: ITC Midwest and ITC Transmission.
[8]	National Grid has a pseudo NERC ID and its comments were attributed to six registered NERC TOs – see http://www.nerc.com/docs/pc/tadstf/NERC_ID_Exceptions_for_TADS_02_18_2008.pdf. Thus, each National Grid response has a "6" instead of a "1" weight. See the Manual, Section 1.9, for a description of pseudo NERC IDs.
[9]	Southern Company Transmission has a pseudo NERC ID and its comments were attributed to five registered NERC TOs – see http://www.nerc.com/docs/pc/tadstf/NERC_ID_Exceptions_for_TADS_02_18_2008.pdf. Thus, each Southern Company Transmission response has a "5" instead of a "1" weight. See the Manual, Section 1.9, for a description of pseudo NERC IDs.
[10]	Comments from Tri-State Generation and Transmission Association were attributed to two Tri-State NERC IDs.
[11]	Comments submitted by WAPA Upper Great Plains Region were attributed to two WAPA NERC IDs.

Table 2
Responses from Reporting TOs by Region[1]

Region	No. of Reporting TOs with Ph II TADS Comments	Total Reporting TOs	Response Rate
FRCC	2	14	14.3%
MRO	5	24	20.8%
NPCC [1]	12	26	46.2%
RFC [1]	12	27	44.4%
SERC [1]	10	24	41.7%
SPP	2	14	14.3%
TRE	4	12	33.3%
WECC	17	63	27.0%
TOTAL	**64**	**204**	**31.4%**

[1] Includes total registered TOs represented by pseudo NERC IDs for National Grid (NPCC), First Energy (RFC), and Southern Transmission Company (SERC).

[1] Reporting TOs are TOs that own one or more TADS Elements. This table is based upon Phase I reporting TOs – it has all reporting U.S. TOs (who must report Phase I data) and all reporting non-U.S. TOs who have indicated that they will voluntarily report Phase I data.

1.2 TO Response Statistics

Most TOs provided answers to the seven questions we asked. Characterizing the responses was challenging – while we received primarily "Yes" or "No" responses, many responses were qualified, and for those we categorized them as "Part." As an example, if someone stated that they collected Phase II TADS data except for transformer outages, we labeled that as a "Part" response to the first question that asked if outage data similar to Phase II TADS is currently being collected. In some cases, the commenter did not answer the question, so we characterized those responses as "Undetermined."

- Our process for categorizing each responding TO's response had two steps: (i) an initial assessment was done by the TF secretary followed by (ii) a review by TF members who were assigned to specific TOs and who suggested corrections. In some cases, a fair amount of judgment was required for characterizing responses.

The resulting inventory of responses is shown on Table 3 below. The first line shows the number of responses and the second shows the percentage of responses to each question.[2] As shown on the table, we sub-divided question 2 and 3 into several parts.

Table 3
Summary of TO Responses to the Questions in Section B of the Request for Comments

	Question	Yes	Part	No	Und
1.	Currently collecting Non-Automatic outage data?	35	19	9	1
		55%	30%	14%	2%
2.a	Is the data reasonable?	18	2	37	7
		28%	3%	58%	11%
2.b	Is the data obtainable?	63	0	0	1
		98%	0%	0%	2%
3.a	Is the 30 min. Planned Outage exclusion appropriate?	37	4	19	4
		58%	6%	30%	6%
3.b	Should a TO record all outage times to determine which outages to exclude?	10	0	11	43
		16%	0%	17%	67%
3.c	Should a TO's supporting data for 30 min. exclusions be part of NERC's data review?	2	0	41	21
		3%	0%	64%	33%
3.d	Does the 30 min. exclusion reduce the reporting burden?	16	0	30	18
		25%	0%	47%	28%
4.	Are the metrics approporiate?	21	8	32	3
		33%	13%	50%	5%
5.	Is a 5-year data retention appropriate?	49	1	12	2
		77%	2%	19%	3%
6.	Is the implememntation schedule reasonable?	34	0	24	6
		53%	0%	38%	9%
7.	Are their ambiguities in Manual?	16	0	44	4
		25%	0%	69%	6%

[2] A total of 64 TO responses were tabulated for each question.

We also tabulated four "paired" question responses for the question pairs shown on Table 4. We felt the paired questions allowed us to better examine responses that one would expect to be correlated.

As an example of interpreting the paired response table, consider the first paired response: Of the 18 who responded "Yes" to the question of whether the data requested in Phase II TADS is reasonable, 15 are currently collecting similar data. Looking again at the first paired response shows that of the 35 TOs that currently collect similar Phase II data (note that adding all "Yes" answers produces 35), only 18 felt that the data request was reasonable. This response was somewhat unexpected. We refer to these paired responses in Section 3 that examines the comments from TOs.

Table 4
Paired TO Question Responses
(Data = No. of Responses)

Data reasonable? (Q.2.a)	Currently collecting? (Q.1)			
Yes	Yes	Part	No	Und
18	15	2	1	0
Part				
2	2	0	0	0
No				
37	15	16	5	1
Und				
7	3	1	3	0

Data reasonable? (Q.2.a)	Metrics appropriate? (Q.4)			
Yes	Yes	Part	No	Und
18	14	3	0	1
Part				
2	1	0	1	0
No				
37	2	2	32	1
Und				
7	4	3	0	0

30 min Planned Outage exclusion OK? (Q. 3.a)	Reduce reporting burden? (Q.3.d)			
Yes	Yes	Part	No	Und
37	17	1	9	10
Part				
4	0	0	4	0
No				
19	1	0	15	3
Und				
4	0	0	0	4

Currently collecting? (Q.1)	Schedule reasonable? (Q.6)			
Yes	Yes	Part	No	Und
35	24	0	8	3
Part				
19	10	0	8	1
No				
9	0	0	9	0
Und				
1	0	0	0	1

2 Comments Resulting in Phase II TADS Changes

We made several changes to the Phase II TADS as a result of comments. These are summarized below:

1. In response to numerous comments expressing concern about the Phase II schedule, we delayed implementation by one-year. Phase II TADS will now require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011 (i.e., Non-Automatic Outages from January 1, 2010 through December 31, 2010). See Section 3.1, pp. 7-8.
2. In response to concerns as to whether Phase II TADS data is a benefit to NERC, we recommended that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. We also recommended that the benefits to NERC of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan**.** Furthermore, we recommended that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees. See Section 3.2, pp. 8-10.
3. In response to Nebraska Public Power District's request that we add a "forced outage rate" metric, we declined to add their suggested formula as a general metric because it may be defined differently by different TOs. However, we will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric. See Section 3.6. p. 17
4. In response to National Grid's comment that TOs should be allowed to enter data in local time instead of Universal Coordinated Time (UTC) since webTADS has this capability, we will modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. We will clarify this in a future update of the Manual. See Section 3.9, p. 22.

3 Responses to Comments

We would first like to thank all those who took the time to submit comments. The TF greatly appreciates the input it received, and as a result the Phase II proposal will be much better.

The sections that follow address common topics. In each section, we provide a single response to similar comments, and we also address selected individual comments.

3.1 The Phase II Schedule

In response to numerous comments requesting a delay in the start of data collection for Phase II data, we made a change to the schedule for Phase II implementation. Several TOs recommended delaying Phase II implementation (previously set for January 1, 2009) by at least a year and stated that the proposed timetable was too aggressive for the in-house systems changes needed to meet the January 1, 2009 date.[3] In total, 38% of the responding TOs felt the implementation schedule was not reasonable.

Since we can delay the start of data collection until January 1, 2010 without disturbing the expected mandatory EIA Schedule 7 reporting requirement that would require the reporting of 2010 calendar year data in 2011, we agree with delaying the TOs data collection start date by one year to January 1, 2010. Therefore, we will require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011 (i.e., Non-Automatic Outages from January 1, 2010 through December 31, 2010).[4]

A one-year implementation delay will allow Transmission Owners to have adequate time to develop the necessary software systems for Non-Automatic Outage reporting.

- We are aware that Phase II will make Transmission Owners responsible for Non-Automatic Outage reporting, and that some of the Non-Automatic Outage data required in Phase II may be logged by Transmission Operators (TOPs) or Reliability Coordinators (RCs).[5] For those Transmission Owners that are not Transmission Operators, an agreement is in place that permits the Transmission Operator to operate the Transmission Owner's facilities. These agreements normally require coordination and cooperation between the parties. Therefore, Transmission Owners will need to coordinate with their TOP and their RC to develop the most efficient and cost-effective method of collecting complete Non-Automatic Outage data for reporting to NERC by a single entity.

We will contract with OATI for modification of webTADS to accommodate Non-Automatic Outage reporting. The schedule that we will pursue with OATI for Phase II is as shown on the next page. OATI concurred with this schedule in direct discussions with the TF.

[3] AltaLink Management, American Transmission Company, BPA, CenterPoint Energy, Exelon, Northeast Utilities, CPS Energy, Dominion, ITC Holdings, National Grid, Northern Indiana Public Service Company, Progress Energy-Florida, Progress Energy-Carolina, and TVA.

[4] U.S. TOs must also submit Automatic Outage data for calendar year 2010 on March 1, 2011.

[5] WAPA-Upper Great Plains Region asked whether NERC could coordinate TADS with Reliability Coordinators. Such a coordination approach would not be feasible due to different RC systems.

Table 5
Phase II webTADS Schedule

Target Date	Phase II Activity
Late Nov. 2008	NERC completes Phase II webTADS requirements and submit to OATI.
Feb. 1, 2009	NERC will publish final specifications for data input and error checking so that TOs may use the specifications to modify their data collection systems.
Feb 1-July 1, 2009	OATI will complete changes to webTADS for Phase II, including system testing with dummy data.
July 1-Dec. 1, 2009	NERC and OATI will conduct Phase II webTADS training. We recognize that some TOs will have different personnel entering Non-Automatic Outage data into webTADS, and therefore we have allowed a long training period.
July 1-Dec. 31, 2009	"Dry run" data entry permitted into webTADS by TOs for any part of their actual or dummy 2009 data. Any 2009 Phase II data which a TO enters will not be retained in webTADS after December 31, 2009.

The last step – a Phase II dry-run period – is designed to allow TOs that will be bulk loading Phase II TADS data to verify the compatibility of their in-house data extraction and transfer protocols with webTADS data input requirements using actual or dummy 2009 data. TOs that will not be bulk loading webTADS data may also test their ability to input actual or dummy 2009 data. Dry-run testing is completely optional, but we believe that TOs who avail themselves of this option will be better prepared for 2010 implementation.

3.2 Reasonableness of the Phase II Data Request

We received numerous comments, some lengthy, that we had not adequately demonstrated benefits that exceeded the burden of collecting and submitting Non-Automatic Outage data to NERC. These came in response to many of the questions that we asked, including whether the data being requested was reasonable (37 of 64 responding TOs, or 58%, said "No") and whether the metrics were appropriate (50% of responding TOs said "No").[6] Two TOs (Baltimore Gas & Electric and TVA) felt that the Emergency Outage data was reasonable, but not the Planned Outage data. The remaining TOs responded as follows (see Table 3): 18 (28%) say the requested Phase II data *was* reasonable, and 7 (11%) responses were undetermined.

We further analyzed the responses of the 37 TOs[7] that stated that Phase II was unreasonable. Many provided several reasons. Table 6 on the next page is a summary of *why* they felt the data was unreasonable.

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[6] WECC also opposed both Phase II and the metrics.

[7] The 37 TOs who said the data requested was not reasonable are: American Transmission Co., Arizona Public Service, BPA, CenterPoint Energy, Exelon (representing two TOs), CPS Energy, Dominion, Duke ((representing two TOs), Idaho Power, ITC Holdings (representing two TOs), Manitoba Hydro, National Grid (representing six TOs), Nova Scotia Power, PG&E, PacifiCorp, SMUD, Salt River Project, Southern Company Transmission (representing five TOs), Tallahassee, Tri-State G&T (representing two TOs), WAPA- DSR, WAPA-RMR, and WAPA-UGPR (representing two TOs).

Table 6
Reasons that 37 TOs Objected to the Phase II Data Request

Why requested Ph II data is unreasonable	No. of TOs	Percent*
No proven reliability benefit	34	92%
High cost of collecting	31	84%
Implementation schedule too short	9	24%
Data may lead to new standards	7	19%
Collection may lead to behavior that degrades reliability or safety	9	24%
Data is not comparable	8	22%

*based on 37 TOs who said requested Phase II data is unreasonable

Some TOs provided separate statements explaining their Phase II objections.[8] BPA and ITC Holdings suggested performing a cost/benefit analysis to determine whether Non-Automatic Outage data collection should be implemented.

While most TOs questioned the long-term reliability benefits that might be derived from Phase II data, two TOs did not see how the Phase II data would be useful towards improving *current day-to-day* reliability.[9] We disagree that the collection of historic Non-Automatic Outage data will have no direct impact on day-to-day reliability. Analysis of historic Planned Outages could improve scheduled outage planning accuracy and therefore day-to-day reliability.

There were some unexpected results. Most responding TOs (35 of 64 responding TOs, or 55%) *already collect* similar Non-Automatic Outage data. Per Table 4, of the 35 responding TOs that already collected similar data, 15 said the data request is unreasonable. Several of those TOs already have in-house software programs, but none said they currently collected it for reliability analysis.[10]

In response to whether we have offered sufficient rationale for Phase II TADS, we point to Section 2.3 of the preliminary Phase II report which cited several reasons for collecting Non-Automatic Outage data:

1. Non-Automatic Outage data will complement Phase I Automatic Outage data, resulting in our ability to capture almost all transmission Element outages.
2. Complete transmission outage information may influence NERC Reliability Standards development.
3. Complete transmission outage information could allow for improved system analysis by bridging gaps between the operating environment and planning assumptions.
4. For U.S. Transmission Owners who are subject to EIA reporting requirements, the reporting of Non-Automatic Outages to NERC could avoid a duplicative reporting requirement to EIA. (We discuss this last reason in Section 3.3 below.)

[8] CenterPoint Energy, CPS Energy, Dominion, Duke Energy, Nova Scotia Power, and Northeast Utilities
[9] Georgia Transmission Company and Southern Company Transmission
[10] Examples include National Grid, TVA (who had decided to suspend the future collection of Non-Automatic outage data that it currently collects) and Duke Energy (who is not currently collecting Non-Automatic outage data, but who has software under development for its collection beginning in 2009).

With respect to the third reason listed above, we provide additional support below which we will add to the final Phase II report:

- From a planning perspective, if planned outages are not properly accounted for in the planning of the system, insufficient facilities may be built, making day-to-day reliability worse.[11] Several TPL standards (TPL-002-0, TPL-003-0, and TPL-004-0) have a requirement that planned outages be explicitly considered. In TPL-002-0, this is found in R1.3.12:

  > "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.

  Historical Planned Outage data could help Transmission Planners with this requirement.

To the four reasons listed above, the TF will add a fifth reason to our final Phase II report:

- No Reliability Standard or NERC rule (in NERC's *Rules of Procedure*) requires the systematic recording of historic system topology for the purpose of analyzing events. TADS will begin to fill this need by collecting both Automatic and Non-Automatic Outage data. Since we only require the submission of TADS data annually, we recognize that the submission of TADS data into webTADS may not occur until months after an event. The requirement to collect TADS outage data means that TOs could, by special request from NERC, provide outage data if required to help NERC analyze an event, and the fact that such data will be entered into a structured TADS database will be helpful.

Finally, we recommend that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. In addition, since the reasonableness of Phase II cannot *presently* be demonstrated with hard facts, we recommend that Phase II benefits to NERC be demonstrated after five years of data has been collected.[12] This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan. Furthermore, we recommend that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees. The five-year data collection period will conclude with 2014 data, which will be collected in 2015. The demonstration of Phase II benefits should be performed on or before August 15, 2015 to allow sufficient time for Planning Committee and Board of Trustees action.

[11] Tallahassee said "The way to improve reliability is to put more wire in the air in areas that show consistent contingency problems." We agree, but getting this result requires a proper representation of the system by transmission planners. If planners assume no Planned Outages at time of system peak, but our data shows otherwise, planners may in fact be able justifiably "put more wire in the air."

[12] Many TOs suggested that we analyze the historic ECAR data to determine it usefulness. ECAR data collection ended in 2005, and while the data was made available to TOs for over 20 years, the use that each TO made of that data would be difficult to determine.

3.3 EIA Form 411, Schedule 7

As explained in Section 2.4 of the preliminary Phase II report, EIA has agreed to leave Schedule 7 collection voluntary for now; mandating Schedule 7 will be re-addressed in the Electricity 2011 project, which will take up the re-authorization of EIA data collection forms, including Form 411.[13]

We expect EIA to mandate that NERC provide Schedule 7 data submittals in 2011, which will require that NERC submit 2010 data to EIA in 2011. NERC plans to use TADS to comply with this expected future requirement. EIA will not address the 2011 filing requirement of 2010 data until early 2010, making there final decision in the fall of 2010. Since NERC cannot ramp up a mandatory collection with only months notice, the start-up schedule described in Section 3.1 needs to be followed.

- Some TOs questioned why we are requesting additional detailed Phase II data over what Schedule 7 requires.[14] First, we believe that the additional data we are requesting will allow NERC to produce metrics with the detail that is consistent with Phase I. Second, we also believe that the additional detail (e.g., listing individual outages with start times and durations) would be part of the normal records kept by a TO to develop aggregated Schedule 7 data. Finally, we added several cause codes that we felt would provide value to NERC, even though they are not required by EIA. For example, we have three cause codes for Planned Outages, while EIA does not have any.

- WECC and several WECC TOs provided this comment:[15]

  > "During the time period in which DOE has allowed the Schedule 7 data collection to remain voluntary, that NERC and DOE work together to develop reasoning and worthwhile uses for the NERC wide collection of the scheduled outage data."

  EIA, federal users, and NERC have had discussions on the intended use of Non-Automatic Outage data. We will continue our collaborative discussions with EIA on the defining the benefits of Phase II.

- In their transmittal letter of WECC's comments, WECC states:

  > "Collectively we are very concerned about NERC's effort to gather this data on behalf of the Department of Energy (DOE) when the DOE would not otherwise have access to this information."

  To clarify, EIA *can* mandate the collection of data by NERC for EIA's use. EIA decided *not* to request access to detailed TADS data, such as individual Element outage start times, durations, and cause codes. As discussed in the preliminary Phase II report, EIA's decision to forego access to Confidential Energy Infrastructure Information (which describes most of TADS individual outage data) was based upon their concerns about maintaining the confidentiality of such data.

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[13] Schedule 7 has been voluntary since 2006. Its collection was primarily triggered by the August 14, 2003 blackout and the realization that the federal government did not have transmission reliability data. EIA wanted to make Schedule 7 mandatory beginning in 2008.

[14] American Transmission Company, CenterPoint Energy, and CPS Energy

[15] Arizona Public Service, Idaho Power, SMUD, Salt River Project, and WAPA-Desert Southwest Region

3.4 Definition of Planned Outage and Operational Outage

TVA, Hydro One, and IESO commented that the term "advanced notice" is ambiguous and suggested that we adopt a time frame for that term. Baltimore Gas & Electric and Pacific Gas and Electric (PG&E) asked that a specific time frame for "deferred" be adopted.

The relevant language of the definitions being questioned is provided below:

- Planned Outage: A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred.
- Operational Outage: A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

We do not believe that these definitions need to include a reference to a specific time frame. TOs may have their own individual time frames, some of which may be specific to a situation. For example, the time frame that constitutes an emergency to protect equipment from damage will be TO-specific and equipment-specific.

The way to determine the category for a Non-Automatic Outage is to first examine the *purpose* of the outage. If its purpose was for "maintenance, construction, inspection, testing, or "planned activities by third parties," it was a Planned Outage. If its purpose was "avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits," it was an Operational Outage.

Second, examine the *timing* of the outage. If it was prescheduled with advanced notice to parties involved with the outage *and* if there was discretion with respect to the outage's actual scheduling, then it was a Planned Outage. If these timing factors are absent, then it was an Operational Outage.

3.5 30-minute Exclusion for Planned Outages

We received many thoughtful comments on the proposed 30-minute exclusion window for switching-related Planned Outages. We had proposed the following language in the definition of Planned Outage:

- "[Planned] Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation of an outage of another TADS Element are not reportable."

Our intent was to eliminate the reporting of "setup switching" or "restoration switching" outages that are not part of an intended Planned Outage. Per Table 3, although 58% of the responding TOs said the 30-minute exclusion was appropriate, only 25% said that the exclusion would reduce the reporting burden. A comment provided by the Sacramento Municipal Utility District (SMUD) captures this contradiction:

> "This is a reasonable exclusion time, do not remove. The exclusion based upon the 30 minute rule has minimal impact on the reporting time as the duration has to be calculated for each reported outage before the outages can be filtered for those that do not meet the exclusion time."

Some agreed with SMUD that the exclusion would have little or no noticeable impact on the reporting burden other than slightly reducing the volume of reported outages.[16] Still others said the exclusion would *increase* the reporting burden because it would not only require recording all outages, but it would additionally require determining which ones should be excluded because they are "setup switching" outages.[17] Tri-State G&T disagreed with the exclusion, noting that it "…will increase the burden on reporting while taking away from one of the main goals of the program" which is the collection of complete outage information. EIA agreed that the exclusion was reasonable, noting while they had set a one-hour exclusion for EIA Form 411, "[i]ndustry standards should be tighter." [18]

Two alternatives were suggested:

a. Record all outages (i.e., remove the 30-minute exclusion) but add a Planned Outage Cause Code or flag for "switching related outages."[19]

b. Do not report <u>any</u> Planned Outages that are 30 minutes or less, regardless of the reason. This would eliminate the need for a TO to determine whether the outage is a switching related outage which is required for the Planned Outage of another TADS Element.[20] Two TOs suggested a blanket one-hour instead of a 30-minute exclusion.[21]

The TF believes that most switching sequences take less than 30 minutes, and we reject the exclusion of all Planned Outages that are 30 minutes or less because of the loss of availability data.[22] While we are concerned with the potential for the 30 minute exclusion to increase reporting effort, we will leave the 30-minute exclusion as proposed and revisit it in the future as feedback from TOs warrants.

3.5.1 Supporting Data for the 30-minute Exclusion for Planned Outages

We also asked whether a TO's supporting data for determining the 30-minute exclusion should be part on NERC's data review. Only 3% of responding TOs said "Yes." Therefore, we will ***not*** require that TOs retain supporting data for determining its 30-minute exclusions for a NERC data review.

3.6 Phase II Metrics

As shown on Table 4, of the 37 responding TOs who said "No" on whether the data requested was reasonable, 32 also responded "No" on whether the metrics were appropriate. Most of the "No" responses to the metrics questioned how the data would be useful. Since many of those comments merely reiterated that the data being requested was reasonable, our response in Section 3.2 above will serve as our response to those metrics comments.

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[16] Baltimore Gas & Electric, Pepco Holdings, Cowlitz County PUD, CPS Energy, Entergy, Georgia Transmission Corporation, Southern Company Transmission, and Southwest Transmission Cooperative

[17] CenterPoint Energy, Dominion, ITC Holdings, NPPD, Oncor, Tallahassee, and TVA

[18] Other entities commented on the 30-minute exclusion: the ISEO and WECC supported the exclusion; Mr. Mitchell of Reliability*First* Corporation did not support it; Mr. Somayajula supported eliminating all outage reporting of switching steps, regardless of duration.

[19] Suggested by CenterPoint Energy and New York Power Authority

[20] Suggested by BPA, Oncor, and TVA

[21] Suggested by CPS Energy (to conform with ERCOT requirements) and Georgia Transmission Corporation (to conform with Schedule 7 requirements)

[22] Northeast Utilities said "Some circuits could take a couple of hours to completely deenergize." While we do not dispute the claim, we believe such occurrences are very rare.

We had several targeted comments that we respond to below:

- CenterPoint Energy said:

  > "No [the proposed metrics are not appropriate]. The metrics will allow for trending of the values from year to year, but are not in themselves indicators of bulk power system reliability. There is also no indication within the Phase II Report if a directional change (up or down) in the trend of any of the Phase II TADS recommended planned outage metrics can indicate better or worse bulk power system reliability. EPRI did not recommend any metrics for planned outages for external benchmarking or regulatory purposes and specifically found no value in the total availability metric (APC) proposed in Phase II TADS."

- TVA said:

  > "The proposed metrics are not appropriate because they can be misleading in analyzing the performance of a robust bulk power system. TVA has built its bulk power system for peak loads, and therefore, has an operating margin for "normal" (non-peak) operating conditions. This margin is used to perform maintenance and perform improvement projects which increase the reliability of the system. Most of the metrics for non-automatic outages could give a false impression of condition or risk without more specific knowledge. The bulk power system does not necessarily suffer since every bulk power line is not critical to daily operation."

We agree with CenterPoint and TVA that we have not tied any of the Non-Automatic Outage metrics specifically to bulk power system reliability. Our Phase II metrics were based upon the Phase I metrics. The following statement from Section 4 of the Phase I report dated September 26, 2007 also applies to Phase II metrics:

> "Given the richness of the data, the metrics described below can be computed for many data combinations. For example, one could calculate the metrics for each Cause Code, for each Outage Mode, for each Event Type Number, and for various combinations of these. We have not established a comprehensive set of uniform metric calculations since we expect that it will take some work with the data itself to tell us which combinations provide meaningful information."

We expect that the Phase II metrics to also evolve as we gather Phase II data and analyze it. Finally, the requirement we set in Section 3.2 to demonstrate the benefits of Phase II after five years of data collection should also demonstrate the benefits of the metrics as they exist at the time of that demonstration.

- Dynegy Arlington Valley said that radial circuit data such as circuit tying a generator into the system should be either excluded or tracked separately since its not part of the "integrated transmission system." The TF discussed radial circuits in Phase I and concluded that the Automatic Outage metrics of *all* circuits were of interest, and that the circuit's configuration (network or radial) was not relevant. We agree that the *consequences* of a network circuit outage will be different than a radial circuit outage, but the basic outage causes are the same. As an example of different consequences, if a radial circuit connecting a generator has an outage, a circuit outage means both the circuit *and* the generator are unavailable. So radial circuit availability can significantly impact the performance of the bulk power system.

- Duke Energy said the mean and median data provided in Phase I and II have little value. PG&E had a similar comment regarding the mean values. For Mean Time to Repair in Phase I, we are calculating a standard deviation and a confidence interval for Phase I data, and will do so for the Mean Element Planned Outage Time and Mean Element Operational Outage Time in Phase II data. We also believe that the median times add perspective to the mean times since one can easily tell if a few events affected the mean by comparing the two. We will emphasize this in our final Phase II report.

- PG&E stated that "availability and reliability metrics are most useful when applied at the individual circuit level." For each Element outage, we require a TO Element Identifier (see the Manual, Appendix 7, p. 8). Although TADS does not maintain a list of individual circuits, individual circuit performance could be calculated by a TO if the TO exports the data it submitted to webTADS for its own analysis.

- Several TOs had expressed concerns about certain "unintended consequences" regarding metrics.

  \- Southern Company Transmission said:

  > "Trending planned outages could lead NERC to suggest standards which might limit Transmission Owners to certain "windows" of time and certain "lengths of duration" for maintenance to be performed. Doing so could possibly do more harm than good to the transmission system."

  \- PG&E said:

  > "There is concern how TADS may ultimately be used to penalize transmission owners that are not meeting metric "averages." The TADS Phase II Preliminary Report states on p. 3 that "Trending of Non-Automatic Outage metrics *within* a Regional Entity may be useful, but comparisons *between* Regional Entities are inappropriate for the same reasons provided in the Phase I report." It further states that "correlations between Phase I Automatic Outages and Phase II Non-Automatic Planned Outages should be approached with caution." Despite these statements of caution (which PG&E supports), there still exists a concern that PG&E may have fines imposed on it if it is not meeting such "average" performance metrics relative to other utilities within the electric transmission system covered by NERC, as we may be providing reliable service to our customers, but still not be in the upper half of the statistical grouping."

  We acknowledge Southern Company Transmission's and PG&E's concern that at some point the TADS data may be used to support a new Reliability Standard. However, the Reliability Standards process is a stakeholder-driven one, and unless the TADS data convincingly supports a new standard, it will not be approved by the stakeholders.

  \- CPS Energy said:

  > "The metrics are not appropriate, since many proposed metrics have no real relevance to the goal of improving the reliability of the Bulk Electric

> System (BES). While such metrics could be viewed as "nice" for reports, the fear that many misrepresented metrics may actually lead towards tendencies to "improve metrics" by reducing maintenance outages could actually occur to the detriment of the BES."

We agree that the unintended consequence described by CPS Energy is a possibility for TOs that focus on the metrics as opposed to what needs to be done to improve reliability. Phase II metrics should not be the sole driver of actual maintenance practices. Maintenance practices should be based upon reliability considerations and good utility practice.

- Hydro One asked:

> "The TADS Phase II Preliminary Report recommends that planned outage performance not be compared among utilities. Does NERC intend to apply this approach to metrics that include the planned outage data?"

The metrics on an individual TO are the confidential performance metrics of that TO and will not be compared on a TO basis by NERC. See Section 5.3.3 of the Phase I report dated September 26, 2007.

- EIA stated the following:

> "EIA believes some of the metrics could be improved. The starting point for developing TADS was transmission outage information. However, the use of the word availability in the title suggests that the system might include additional information. This would include such metrics on both outage and equipment failure rates (protective system failure to open, to close, to operate, and protective system false operation rates). Other key information that needs to be linked with these metrics deal with the exposure (time and operations) associated with weather; that is, normal, adverse, and major storm disasters. In addition, EIA hopes that the restriction of only tracking events impacting power flows through designated points in the Phase II TADS will be expanded to address individual components or equipment that are outside of the set parameters of Phase II TADS, but which are linked into the high voltage transmission systems."

When Phase II is implemented, TADS will track the complete operational history of four classes of Elements that are ≥ 200 kV: AC Circuits, DC Circuits, Transformers, and AC/DC Back-to-Back Converters. These Elements are equivalent to the IEEE Standard 859[23] definition of a "component." There are various methods for defining a component. As an example, an AC Circuit can be subdivided into its constituent components of conductors, insulators, series compensation, etc. Our TADS definitions are very specific on what facilities are included or excluded in the definition of an Element, which is our lowest level of measuring performance. We could have gone to a lower equipment component level such as the approach used by the Canadian Electricity Association. However, we elected to keep the process less detailed at the outset so as to not

[23] *IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outages States of Electrical Transmission Facilities*

overcomplicate start-up. Also, we are currently more detailed in our data requirements than Schedule 7 in EIA's Form 411.

In the TADS framework, we will have Element outage frequency rates and failure rates. With regard to Protection System failures, we have not defined the Protection System as a TADS Element to be tracked. (The term "Protection System" is defined in TADS and is the same definition used in NERC's Reliability Standards.) Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems – requires each Regional Reliability Organization to "establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations." We realize that potential metrics could be developed if TADS were linked to the data derived from these standards, and while that is not a practical goal at this point, it could be part of a TADS expansion at a future date.

EIA's suggestions for expanding TADS can be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).

- NEMA provided comments related to additional future data for Transformers:

> "[We] would find additional detail on equipment characteristics beneficial. For a given outage, a unique element identifier is already reported. NEMA would find it particularly useful to also record the date of manufacture or in-service date of that transmission element, either through the same form or through a separate table linking the transmission element to its nameplate characteristics. For transformers, other nameplate information would also include power rating, voltage rating, BIL rating, insulation class, cooling class, temperature class, impedance, frequency and presence of a load tap changer.

NEMA's suggestions will be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).

- Nebraska Public Power District (NPPD) asked that we develop a "forced outage rate" metric that reflects both Automatic Outages plus Operational Outages. The task force has had difficulty with the term "forced outage rate" because it may be defined differently by different TOs, and we will not add this as a general metric. For example, the Canadian Electricity Association defines a "forced outage" in TADS terms as Automatic Outages plus Non-Automatic Operational Outages with an Emergency Cause Code. However, NPPD's suggestion has merit. We will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric.

3.7 Maintaining Five-Years of Supporting Data

Although 77% of the responding TOs agreed to the proposed five-year period for the retention of supporting TADS data, 19% (12 TOs) felt it was unreasonable. Specific negative comments are shown below, and responses to all of them are provided in a coordinated discussion at the end of this section.

IESO said:

> "While the IESO supports the need to ensure validity and quality of data, we believe 5 years is excessive and support a shorter data retention period of 3 years. The IESO is unaware of any existing process to validate EIA data and question the need here."

Entergy said the five-year retention period was reasonable, but said:

> "….guidelines on acceptable documentation would be helpful in assuring no efforts are put into going overboard in this effort."

WECC and six WECC TOs said:[24]

> "This is an unreasonable request. Past years' data is often incompatible with current data because of potential circuit definitions changes in each system and potential metric definition changes."

PacifiCorp expressed a similar concern:

> "It is not reasonable to maintain TADS-quality data for an extended period of time. The further away the event occurred, the less likely it can be readily replayed and understood. As a result, derivative metrics for a given time period may make sense, however the raw data documenting any planned outage activities does not make sense due to the ever-changing nature of the delivery system, including generation locations, transmission corridors and markets."

CenterPoint Energy stated:

> "The data review process requirements for the Regional Entities and the webTADS error checking features implemented in Phase I should provide the necessary level of data validation. Data errors should be able to be corrected within the annual NERC reporting process. The webTADS database should serve as the historical repository for analytical purposes and replace the need for the proposed 5-year record retention and review process for the transmission owners."

ITC Holdings said:

> "It appears that the choice of the 5 year retention period was arbitrary. Again the maintenance and archiving of such data will require additional resources for a yet to be determined benefit."

[24] Arizona Public Service, Idaho Power, SMUD, Salt River Project, WAPA-Desert Southwest Region, and WAPA-Rocky Mountain Region

Tallahassee stated:

> "1. If NERC can't determine that my data is accurate rapidly, they are collecting too much information or not collecting the correct data to start with.
> 2. Why are you placing the burden of record retention on the [reporting] entity? We have enough other NERC "stuff" to track and retain.
> 3. The "historical supporting information" is not clear. This can be anything and everything! And I am sure what I think I need to retain would not be the same that you think I need to retain, especially if this turns into a Standard."

EIA recommended:

> "… extending the period of [keeping] historic period [data] beyond 5 years. For example, the age of many types of installed equipment or components on the bulk power systems could easily be described as mature. Failure rates attributed to age and their associated failure trends are best observed over a wider base of years."

Our response to all of the comments above follows.

As described in Section 5.1 of the preliminary Phase II report, we intend to conduct a data review with each reporting TO with the objective of ensuring that the TO has a reasonable and consistent process for both interpreting the outages and recording the data. To answer IESO's comment, there is no existing NERC process to validate EIA data that NERC voluntarily collects and submits to EIA, and EIA has rightfully questioned the validity of such data. To answer CenterPoint Energy's comment and Tallahassee's first comment, we do have data error checking capability built into webTADS, but that is no guarantee that the data has been collected reasonably and that the instructions were interpreted properly.[25] Regarding Tallahassee's second comment, the entity that submits TADS data is responsible for its accuracy and completeness.

While NERC's review of a TO's collection process and supporting data will cover the most recent reporting period, NERC cannot practically review 192 reporting entities[26] in a single year. The five-year retention period allows NERC to accomplish a review of every TO, and if a TO which NERC visits in the fifth year has a systematic reporting error, past data entries can be corrected. While the five-year policy may have appeared arbitrary to ITC Holdings, we realize that we did not explain it fully and will do so in the final Phase II report.

We agree with the WECC, the six WECC TOs, and PacifiCorp that past data may be incompatible with current data and that circuits may have changed. Changes will occur every year. Nevertheless, to ensure that the data has been consistently collected by all TOs, TOs need to maintain historical supporting information. Tallahassee correctly notes that we have not defined what comprises "historical supporting information," and Entergy also asked for "guidelines." What a TO should keep for documentation is best determined by the TO, but a simple guideline is this: any information that a TO relied upon to complete a webTADS data entry should be kept for five years.

[25] For an analogy, a tax return filed to the Internal Revenue Service undergoes many logic and consistency checks before it is accepted. While that does mean the data entered is consistent with the logic checks, it does not mean that the tax payer has properly interpreted the tax regulations.
[26] 192 reporting entities equals the NERC IDs and the current pseudo NERC IDs that are reporting Phase I data.

Regarding EIA's comment, TADS data itself will *not* have a time limit for data retention. What we are limiting is the time that a TO needs to retain its historical supporting data for its entries into TADS.

3.8 Non-U.S. Reporting Requirements

In response to Manitoba Hydro's comments asking whether Phase II TADS data is required from Canadian utilities, we clarify that Phase II TADS data *is* required of non-U.S. Transmission Owners that are also NERC members. See Section A.3 of the April 30, 2008 request for comments which states **"**Non-U.S. Transmission Owners [on the NERC Compliance Registry] who are also NERC members are required to comply with NERC's *Rules of Procedure*, and because Phase II TADS data are being requested in accordance with Section 1600, [these] non-U.S. Transmission Owners too must provide Phase II TADS data."

In response to comments from Manitoba Hydro, Hydro One, and the IESO, we clarify whether any TADS data submitted by a Canadian entity will be reported to EIA or FERC:

- In the Phase I Report dated September 26, 2007, p. 6 states the following in footnote 6: "TADS data from Canadian Transmission Owners will not be reported to EIA unless approved by those Canadian TOs."
- In the preliminary Phase II report, p. 10 states the following in footnote 13: "Each ERO governmental authority would be able to access confidential information for Transmission Owners that it regulates, e.g., FERC would only be able to access TADS data for U.S. Transmission Owners, and an appropriate Canadian provincial regulatory body would only be able to access TADS data for its provincial Transmission Owners."

3.9 The Manual

While most TOs were complimentary of the Manual, 16 TOs reported ambiguities in the Manual. Exelon and ITC Holdings (representing a combined five TOs) asked for better justification for Phase II in the Manual, but this is not the purpose of the Manual.

From other TOs, we received several good Manual "content" questions:

- Hydro One and TVA asked that we provide an example of human error as described in the "Other Planned Outage" Planned Outage Cause Code. NPPD asked for an example of "Other Planned Outage." We respond to both questions with one example: If the outage instructions are mislabeled and, as a result, the wrong circuit is opened for a Planned Outage, the mistake will eventually be realized. If the situation is rectified by opening the intended circuit and restoring the unintended circuit, the unintended circuit would have an "Other Planned Outage" Planned Outage Cause Code because the outage was due to human error. The intended circuit would have a "Maintenance and Construction" Planned Outage Cause Code.
- NPPD and Entergy had similar questions regarding two parties being involved in an outage request. We provide NPPD's question directly:

> "If a Third Party (for example: the department of roads or a house mover) requests an outage and the TO uses that outage opportunity to do maintenance to the line, does it still classify as a Third Party Outage or does it now become a Maintenance Outage? Are there any situations where a

> planned outage starts out as a Third Party outage, but then becomes a maintenance or operational or "other" type of outage?"

Only one Cause Code is reported for each Non-Automatic Outage. For Non-Automatic Outages, the Cause Code that contributes to the longest duration should be reported similar to the definition for Sustained Cause Code. See the Manual, Appendix 7, p. 13, item E.1.

Returning to the previous example, suppose that the outage for the road department is expected to last four hours, and maintenance is scheduled for this interval. However, in the process of performing maintenance, additional work is discovered that is unexpected, and the outage is extended to seven hours to accommodate this additional work. Since maintenance contributed to the longest outage duration, the outage is classified as a "Maintenance and Construction" Planned Outage Cause Code since this code represented all seven of the outage hours, while "Third Party Request" only accounted for four hours. We will add language and examples in the Manual that clarify this situation.

- Reliability*First* Corporation asked that we expand two Operational Outage Cause Codes: H.2 (System Voltage Limit Mitigation) and H.3 (System Operating Limit Mitigation, excluding System Voltage Limit Mitigation) into the four separate codes using the System Operating Limit causes listed in H.3 (see the Manual, Appendix 7, pp. 16-17):

  - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
  - Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
  - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
  - System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

  We purposefully combined the first three System Operating Limits causes into one cause code (H.3) since the research needed to determine the exact underlying limit cause may be extensive. On the contrary, the opening of an Element to maintain system voltages is readily known and assigned its own separate cause code.

- Reliability*First* Corporation asked that the Planned Outage Cause Code for "Maintenance and Construction" have two additional cause codes added: One for "Maintenance" and a second of "Construction" where each would describe an activity that is 100% maintenance *or* construction, with the "Maintenance and Construction" describing activities that are combined. We considered this alternative and rejected it for the reasons described in the last paragraph of Section 2.1.1 of the preliminary Phase II report.

- TVA noted that in Appendix 7, p. 19, the definition of Voltage Classes includes 400-499 kV and 500-599 kV, while for AC Circuits only 400-599 kV is used. That is correct as explained in Section 1.2.1, p. 2, of the Manual. TVA also pointed out several typographical errors, which we will correct.

- Northeast Utilities said "under Phase I, the changes seemed to occur continuously without any notification of changes." We announced all the Manual changes; however, due to the coincidence of the Phase II comments with a Phase I update, we announced the Phase I update in the April 30, 2008 request for comments. See the first bullet on the first page of the request for comments. We regret any confusion and will not use this practice in the future.

- San Diego Gas & Electric said that "a good system to clarify and ask questions should be in place." We have such a system as described in Section 1.8, p. 7, of the Manual.
- National Grid asks "that future document change control be more formalized and that for any future Phase I (and Phase II if approved) TADS changes that NERC limits the frequency of updates, if any, to a quarterly basis." National Grid's suggestion will be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).
- National Grid also notes that OATI's webTADS has the capability of allowing outage start times to be entered in local time rather than Coordinated Universal Time, and asked that the TF revisit its decision to require UTC entries. We will modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. We will clarify this in a future update of the Manual.
- Hydro One said "it is not clear why the collection of terminal station names is necessary. It should be sufficient to collect the number of station terminals associated with each circuit for the calculation of the metrics. This would add value to the metrics."

  We require that each AC Circuit outage provide Substation Names because this provides others, such a Regional Entities and NERC who review TADS data, a physical location of the circuit. When we are trying to determine whether an Event has propagated between more than one TO, the Substation Names, along with the Outage Start Times, provide a basis for initiating a check with the appropriate TOs. Thus, we will have the number of terminals associated with each outaged circuit.

  What we do *not* collect is an inventory by Voltage Class of the number of circuits with two terminals or three terminals. Neither do we have an inventory of the total number of substations by Voltage Class. We agree that such data would have probable metric value, and it was debated in early 2007 when the TF was formulating its Phase I data requirements. However, it was not adopted. It will be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).
- PG&E said that instead of requiring TADS "It would be more beneficial for NERC to simply define "best practices" for outage data collection and establish timetables for transmission owners to adopt those best practices." That suggestion would not meet the minimum goals set forth in the TADSTF scope, which included standardizing the data collection process. See Appendix 1 of the Phase I Report dated September 26, 2007.

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