Transmission Availability Data System
Revised Final Report

Prepared by:

Transmission Availability Data System Task Force

For:

NERC Planning Committee

September 26, 2007

Approved by the Planning Committee on: **September 26, 2007**

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Preface

This revised final report is an update of a June 7, 2007 final report on the same topic – a Transmission Availability Data System (TADS). Since the earlier report was completed, the TADS Task Force (TF) posted the report and a Phase I TADS Data Reporting Instruction Manual dated June 29, 2007 for public comment. It also conducted a Beta test using actual data from four Transmission Owners who are represented on the TF. Descriptions and results of both these efforts are included in this report. Both efforts impacted the Phase I data requirements, and those changes have been incorporated in this revised report. In addition, timetables have been updated.

1. Executive Summary

The Transmission Availability Data System Task Force (TADSTF or TF) was formed on October 24, 2006, with the objective of defining a uniform approach to reporting and measuring transmission availability and performance, referred to as the Transmission Availability Data System (TADS). The TF members came from all eight NERC regions and had both U.S. and Canadian representation. We researched industry practices and debated the many facets of our goal, carefully weighing the burden of collecting each "piece" of information with the benefit and usefulness of that information. We recognize that the initial structure proposed in this report will be enhanced and improved over time as the industry gains experience. Changes are natural to any data system. Some information that we have specified may not turn out to be as useful as we expected, while other information, not felt to be important at this stage, may be added as TADS evolves. We did not lose sight of the fact that collecting data is done for the overriding purpose of providing Transmission Owners (TOs) and NERC with the information to support decisions with respect to improving reliability and performance. Since becoming the Electric Reliability Organization, NERC has taken on the role of being an independent source of reliability performance information, thereby fulfilling one of the recommendations in the April 2004 U.S.-Canada Power System Outage Task Force Report on the August 14, 2003 blackout.

We are proposing to implement TADS in two phases.

- Phase I will require that TOs report only Automatic Outages beginning with data for calendar year 2008. Subject to approval by NERC's Board of Trustees (board) at its October 23, 2007 meeting, Phase I TADS reporting will become a mandatory data submittal requirement on all Transmission Owners registered on the NERC Compliance Registry.
- 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.

Therefore, the majority of this report describes Phase I, although certain aspects of TADS (such as confidentiality and the data reporting process) are not expected to change when Phase II is added. These are the key aspects of Phase I TADS:[1]

a. We recommend collecting outage data on four specific transmission Elements which operate at voltages ≥ 200 kV:
   - 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

[1] Definitions found in Appendix 2 are capitalized in this report.

- DC Circuits with ≥ +/-200 kV DC voltage

b. We chose a framework that requires TOs to report aggregate transmission population inventory data by Voltage Class while at the same time requiring the reporting of specific data for each Element outage.

c. We recommend collecting Automatic Outage data only, both Sustained and Momentary. Automatic Outage data provides a simple rule for capturing the majority of unscheduled outages, and it is one which was not subject to interpretation difficulties.

d. Our data collection and processing protocol relies upon the cooperation of Regional Entities (REs).
   - An RE may request additional data from the TOs in their footprint.
   - Each RE will be the first organization to receive data and check it for accuracy and consistency.

e. In late October 2007, we will be issuing an RFP for the development of a TADS software data system to support data entry, data management, and data analysis and reporting.

f. We took reasonable steps to ensure the confidentiality of data that is reported so that a TO's confidential *individual* data will be protected from public disclosure.

g. We posted TADS for public comment and made several changes as a result the suggestions we received.

h. We conducted a Beta test using actual data from four Transmission Owners who are represented on the TF. We further modified TADS as a result of that test.

i. 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.

j. 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.
   1. Outage frequency per Element (Sustained, Momentary, and total)
   2. For AC and DC Circuits, outage frequency/100 Circuit Miles (Sustained, Momentary, and total). In addition, we will be computing the number of multiple circuit outages described by Event Type Nos. 30 and 40 per 100 Multi-Circuit Structure Miles for Overhead AC and DC Circuits.
      i. We will supplement the "per 100 mile" calculations with calculations that will remove outages not related to circuit mileage.
   3. For Sustained Outages:
      i. Outage Duration per Element
      ii. Mean Time Between Failures-MTBF
      iii. Mean Time to Repair – MTTR

iv. Median Time to Repair - MdTTR
4. Percent Availability
5. Percent of Elements with zero outages.
6. Percent of Element outages that were associated with a disturbance report.

k. On an annual basis, we will report a set of common set of metrics for each region and for NERC as a whole, which will be available to the public. However, each TO will also receive a confidential summary of their company's data and metrics.

l. The proposed timetable for 2008 calendar year data is shown below. This timetable includes a two-part submittal of 2008 data with an interim NERC report on first quarter 2008 data. This step is proposed so that any difficulties encountered in the initial submittal could be identified and corrected before the end of 2008.

Phase I TADS Timetable for the 2008 Reporting Year

Date	Item
Late October 2007	NERC issues data request to REs if board approve TADS
Mid-November 2007	REs submit a bundled data request to TOs.
December 17, 2007	REs ensure that all tie lines and jointly-owned facilities have a single TO with reporting responsibility.
May 30, 2008	TOs submit data to REs for the first quarter ending March 31. This includes inventory data as well as outage data.
July 15, 2008	REs submit data to NERC after performing an initial data review.
September 26, 2008	NERC completes an interim report on the results, after performing its data checks.
March 1, 2009	TOs submit all remaining 2008 data to REs.
Late June, 2009	NERC completes a final 2008 report on the results, after performing its data checks.

m. Starting with the 2009 reporting year, we recommend the timetable below. Since this will be a normal reporting year, it omits the two-part submittal of data and the interim NERC report that are in the 2008 schedule.

Phase I TADS Timetable for 2009 Reporting Year

Date	Item
Mid-December, 2008	REs reconfirm that all tie lines and jointly owned facilities have a single TO with reporting responsibility.
March 1, 2010	TOs submit data to REs for the reporting year of 2009.
Mid-April, 2010	REs submit data to NERC after performing an initial data review.
Late June, 2010	NERC completes a final 2009 report on the results, after performing its data checks.

n. The tables below show the future activities of the TADSTF.

Phase I TADS Next Steps

Dates (2007)	Activity
October 17	Post an updated Data Reporting Instruction Manual.
October 23	Board of Trustees decides on whether to approve Phase I TADS for mandatory 2008 reporting.
Late October	Issue RFP for TADS software.
Late October	NERC issues data request to REs if board approve TADS.
Mid-November	Start Phase I TADS training.

Phase II TADS Next Steps

Dates (2008)	Activity
Late February	TF will issue a report to the Planning Committee recommending the details of Phase II for approval at its March 2008 meeting.
March	Planning Committee meeting to review and approve Phase II TADS.
Early April	TF will post its Phase II final report, as modified with the Planning Committees' recommendations in March 2008, and its updated Data Reporting Instruction Manual for comments (45 days).
Early July	Submit updated Phase II final report (including comments received and our response to them) to the Board of Trustees for approval at its August meeting.
August	Board of Trustees decides on whether to gives Phase II TADS its approval for mandatory 2009 reporting.

2. The Task Force's Work

2.1. Scope

The TF was initiated by the Planning Committee's Executive Committee on October 24 2006, and announced with in a letter from Scott Helyer, the chair of the Planning Committee.[2] On the premise that transmission availability data will help quantify system performance and reliability, we were to recommend:

a. The type of transmission availability data that transmission owners will report to NERC;
b. A single process for collecting such data that avoids duplication of effort;
c. The transmission availability statistics that would be calculated from the reported availability data; and
d. Guidelines for release of such data and statistics.

To accomplish this purpose, we undertook theses specific activities:

a. Catalog the type of transmission availability data currently being recommended and/or collected by NERC members and other industry groups (i.e. EPRI, CEA) as well as the uses of the data.
b. Recommend a common data reporting framework or protocol.
c. Develop common availability statistics that could be computed from the data.
d. Recommend guidelines for the sharing and release of data.

The TF members came from all eight NERC regions and had both U.S. and Canadian representation.[3] Six meetings and numerous conference calls were convened. A March 7, 2007 Interim Report that described our decisions in structuring TADS was approved by NERC's Planning Committee at its March 21-22, 2007 meeting. A June 7, 2007 Final Report was also approved by the Planning Committee. The June 7 report and the June 29, 2007 Data Reporting Instruction Manual were posted for public comment. In addition, four Transmission Owners affiliated with different TADSTF members provided TADS data for the period from July 1, 2006 through December 31, 2006 to Beta test TADS. As a result of the comments received from the posting and our Beta test results, we made several changes to TADS which are incorporated in this report.

2.2. Industry Practices Reviewed

We started by studying several existing transmission availability data collection models, and the resulting recommendations are largely built upon this body of work. We reviewed these frameworks:

a. The EIA's Form 411 which contains a Schedule 7 that requires the reporting of certain transmission availability data. It can be found at http://www.eia.doe.gov/cneaf/electricity/page/forms.html

[2] See Appendix 1.
[3] Members are listed Appendix 6.

b. The Western Electricity Coordinating Council's framework, which is collecting data for calendar year 2006. It can be found at http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=160.

c. The former East Central Area Reliability's framework, which published its last report in 2005 for calendar year 2004 data. It can be found at http://www.ecar.org/publications/TFP/2005-TFP-46.pdf.

d. The Canadian Electricity Association's (CEA's) framework described in *2004 Forced Outage Performance of Transmission Equipment*, which can be ordered from CEA.

e. The Electric Power Research Institute framework, *EPRI Transmission Grid Reliability Performance Metrics, Final Report*, dated July 2006 (Project No. 104335), which can be ordered from EPRI.

f. The Institute of Electrical and Electronic Engineers, Inc. (IEEE) Standard 859-1987, *IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outage States for Electrical Transmission Facilities*, which can be ordered from IEEE.

g. *Transmission Line Availability Data Guidelines and Definitions* by Gregg A. Spindler of SGS Statistical Services and Edward A. Kram, P.E., of Blue Arc Energy Solutions, Inc., dated February 2003. It can be found at http://www.sgsstat.com/.

In addition, TF members shared their own organization's approach to collecting transmission availability data. These presentations are posted on NERC's Website at http://www.nerc.com/~filez/tadstf.html under the "TADSTF Presentations - November 20-21, 2006 (Chicago)."

2.3. EIA Data Collection Efforts

On April 4, 2007, the EIA issued a notice in the Federal Register (p. 11637) soliciting comments on its proposed revisions and a three-year extension to several of the forms that EIA uses for data and information collection. Under their proposal, Form 411 would require mandatory reporting by Regional Entities to NERC (and NERC to EIA) of transmission outage information beginning in 2008 for what is now voluntarily submitted in Schedule 7 of the existing Form 411.[4] This reporting is now voluntary. We believe that two requirements for transmission data collection (EIA and TADS) is unwarranted, and therefore two TF members, Jean-Marie Gagnon and John Seelke, met with EIA officials on May 16, 2007, to review the scope of TADS and discuss allowing NERC to submit TADS data to EIA in lieu of the data required in Schedule 7.[5,6] EIA's decision will not be made until the fall of 2007 when the proposed forms will replace the current

[4] It is Schedule 6 in the proposed Form 411 because a prior schedule was deleted. The new draft Form 411 is at http://www.eia.doe.gov/cneaf/electricity/page/fednotice/elect_2008.html.
[5] EIA personnel in attendance were Scott Sitzer, Robert Schnapp, Tom Leckey, and John Makens.
[6] TADS data from Canadian Transmission Owners will not be reported to EIA unless approved by those Canadian TOs.

forms which expire on October 31, 2007. If Schedule 7 is made mandatory, the first reports due in 2008 would report 2007 transmission outage data.

At the meeting, EIA praised TADS for (i) the level of outage detail and the attendant definitions associated with Automatic Outages, (ii) the inclusion of Elements not required by Schedule 7 (Transformers and AC/DC Back-to-Back Converters), (iii) the inclusion of Element inventory data (also not required in Schedule 7) which permits outage metric calculations, (iv) the calculation of proposed TADS metrics (Schedule 7 makes no metric calculations), and (v) the data collection and oversight efforts to ensure data accuracy. In addition, the public reporting of TADS data by regions is consistent with Schedule 7 reporting requirements.

However, EIA was concerned with that fact that TADS (as designed at the time of the meeting) did not require the collection of scheduled (i.e., planned) outage data now required in Schedule 7. They felt that such data would be a valuable indicator of transmission maintenance practices through time. Scheduled outages could impact the level of forced outages (i.e., less maintenance could mean more forced outages). In addition, they felt that historical scheduled outage statistics might reveal needed increases in planned outages as a result of transmission infrastructure aging. For TADS to substitute for Schedule 7, EIA felt that TADS would need to provide comparable Schedule 7 data. If this could be accomplished, the EIA representatives felt that Schedule 7 could be administratively amended *after* its approval in the fall of 2007 so that TADS data collected for calendar year 2008 could substitute for comparable data specified in Schedule 7. This would include EIA adopting TADS definitions. Other EIA-TADS differences include a lower voltage level class for DC Circuits (EIA has one lower voltage class of 100-199 kV for DC Circuits), and the reporting on manual unscheduled outages, which EIA reports and TADS does not.

EIA also expressed concern that NERC's confidential information polices may be more restrictive than the Freedom of Information Act (FOIA) policies that guide their handling of confidential information. To be clear, Schedule 7 data contains *regional* outage data, not company-specific outage data. We will address EIA's confidentiality concerns first.

According to EIA, under FOIA (in general), the information that EIA receives may be treated as confidential information (and therefore protected from public disclosure) under one of two broad categories: (i) the information is proprietary business information, the release of which would harm the provider's competitiveness, or (ii) the information would release critical energy infrastructure information. As an example, transmission system maps and power flow cases provided by NERC to EIA under current Form 411 requirements are only disclosed pursuant to EIA's confidential policies. Finally, EIA routinely applies procedures to ensure that confidential information is not disclosed in statistical information that it publishes. This same policy is what we are proposing for TADS (see Section 2.4.7).

NERC's confidentiality policies are defined in Section 1500 of NERC's Rules of Procedures (see footnote 9 in Section 2.4.7). NERC's definition of "confidential information" has the same two FOIA confidentiality information categories that EIA uses. To summarize, we see no conflict between EIA's confidential information policies and NERC's confidential information policies based on our preliminary review. However, further review, as discussed below, is warranted.

As described in Appendix 3, we disagree with EIA on the need for scheduled and manual unscheduled outage data. Nevertheless, in order to have TADS serve as a single source of transmission outage data for both NERC and EIA, we recommend a Phase II expansion of TADS to incorporate scheduled and manual unscheduled outages beginning with data reported for calendar year 2009.

Phase I will require the reporting of Automatic Outages only beginning with data reported for calendar year 2008. A phased TADS implementation will give us additional time to design and recommend an appropriate set of definitions and a data reporting structure for scheduled and manual unscheduled outages. If we are going to require the collection of this data, we want it to be collected in a way that provides the greatest benefit rather than just adopt EIA's current definitions and data structure. In addition to designing a system for the collection of these outages, our Phase II efforts will review the benefits of collecting outage data for DC Circuits in the 100-199 kV range. We will provide a recommendation to the Planning Committee on Phase II details at its March 2008 meeting.

With respect to EIA's proposal to make Schedule 7 mandatory in 2007, NERC filed comments on June 12, 2007 that are summarized below:

1. Making Schedule 7 mandatory for 2007 calendar year data will impose a burden on many U.S. TOs since TOs were not notified of the mandatory collection requirement *before* 2007. As a result, many TOs will have to manually construct the requested data from historic outage records. Therefore, we suggested that EIA make submissions of 2007 data voluntary as they have been in the past.
2. For submission of 2008 and 2009 calendar year data, we proposed that EIA work with NERC to adopt NERC's mandatory outage reporting framework as the single outage framework for both NERC and EIA requirements. It is our understanding that this could be accomplished by administrative changes to Schedule 7 in order to align it with TADS or by replacing the data sought in Schedule 7 with TADS. These discussions could commence in the late fall of 2007, assuming TADS is approved for mandatory implementation by NERC's board. Our discussions would include (i) our proposed phased implementation, (ii) an identification of EIA's administrative processes and timeline needed to accomplish NERC's objective of making TADS the sole source of transmission outage data for both NERC and EIA, and (iii) the resolution of confidential information concerns by both NERC and EIA.

2.4. Fundamental Phase I TADS Structure Decisions

After reviewing these frameworks, we agreed that whatever data and metrics are recommended by the TF, they should be:

- Comparable (consistent framework)
- Attainable
- Verifiable
- Simple

- Relevant to various "users"
    - Transmission Owners, Transmission Operators, and Planning Coordinators
    - NERC (a.k.a., the Electric Reliability Organization)
    - Governmental bodies (the Federal Energy Regulatory Commission (FERC), EIA, etc.)

In developing the TADS structure, we had to continually balance several factors: the level of data detail, the level of effort required to collect the data, and the usefulness of the resulting metrics. Taking these factors into consideration in its deliberations, we recommended the Phase I TADS structure described below. Our initial Phase I TADS structure may be enhanced and improved over time. The definitions that are contained in Appendix 2 are capitalized terms

2.4.1. TADS Elements

We recommend collecting data on four specific transmission Elements which operate at AC and DC voltages ≥ 200 kV. This voltage cut-off was the same one used by WECC and ECAR, and its selection also limits the scope of the start-up effort while providing NERC with a consistent framework for data collection. This same voltage cut-off was also used in the NERC Transmission Vegetation Management Program standard FAC-003-1.

1. AC Circuits ≥ 200 kV (Overhead and Underground Circuits). Radial circuits are included.
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

2.4.2. Voltage Classes

The following Voltage Classes are defined 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 reported Voltage Class will be the high-side voltage, even though the cut-off voltage used in the definition for Transformers is referenced on the low side.

2.4.3. Inventory Data

We chose a framework that requires TOs to report aggregate transmission population inventory data by Voltage Class while at the same time requiring the reporting of specific data for each Element outage.

- For example, data on the number of AC Circuits in a particular voltage class (aggregate level data) would be reported rather than data describing the characteristics of each individual circuit (length, structure type, terminal names, etc.). Inventory data is needed to calculate metrics such as the outage frequency per Element.

- However, each Element outage has specific data reporting requirements, which are described in Section 3.

This reporting framework focuses on collecting detailed outage data while avoiding the start-up effort associated with a detailed Element data base.

2.4.4. Outage Types

We decided to report only Automatic Outages (i.e., outages which result from the automatic operation of a switching device) in the initial Phase I implementation of TADS. Automatic Outages provide a simple rule for capturing the majority of unscheduled outages, and it is one which was not subject to interpretation difficulties.

- Automatic Outages will be classified into two categories: Sustained and Momentary, where Momentary Outages have durations less than one minute.

With respect to other outages, we initially excluded the requirement that TADS collect planned outage data, a step that was approved by the Planning Committee at its March 21-22, 2007 meeting. Appendix 3 describes the analysis we undertook to evaluate the collection of planned outage data, as well as the impact of *not* collecting such data on certain metrics. However, as described in Section 2.3, we are recommending they be collected in a TADS Phase II effort in order to have TADS serve as a single source to NERC and EIA data for transmission outage data.

2.4.5. Impact Measures

We discussed what impact measures to track which are associated with an Event. Because TADS will be reporting on the performance of part of the transmission system, we understood that load lost or transmission service interrupted due to outages of the TADS population would capture a subset of those impacts.

Delivery point metrics, which would define the ability of the transmission system to provide power to load delivery points, were not easy to define. We felt that the definition of a load delivery point should not include any distribution system elements. As an example, CEA collects delivery point interruption performance data, where a delivery point is defined as the point where energy is transferred from the transmission system to the distribution system. Their point of reference is the low-side voltage of the step-down transformer. However, in the U.S., such transformers would be distribution or customer-owned assets that are outside of NERC's purview. True delivery point metrics would exclude load-serving step-down transformers. Likewise, we recognized that the majority of the load is served at voltages that are below the AC 200 kV TADS cut-off.

EPRI also studied the complexities of delivery point metrics which is discussed in detail in the *EPRI Transmission Grid Reliability Performance Metrics, Final Report*. EPRI developed a delivery point general common model to minimize the comparability issues resulting from different individual utility methodologies. The model recognizes the contribution of transmission sources and transmission substation equipment on the transmission side (high side) of transformations, but it *does not* recognize the contribution of "low side" or "non-transmission" (i.e. below 44 kV) redundancy common in some vertically integrated utility substation designs and transmission customer substation designs. In other words, the model does not measure a "lights out" condition of the customer in cases where there are "non-transmission" sources providing a back-feed.

In light of the above complexities, we decided to require TOs to report whether a disturbance report was filed that was associated with each Event ID Code as a simpler way to indicate the impact of transmission line outages on customers. NERC requires the reporting of disturbances in the current version of its reliability standard EOP-004 (Disturbance Reporting).[7] The OE-417, which is the Department of Energy's Electric Emergency Incident Report and that is a requirement for U.S. utilities[8], can be used as a substitute for Attachment 2 in the current version of EOP-004.[9]

A TO whose Transmission Operator has filed a report will likely be aware of the report and whether outaged facilities were related to the reported disturbance. However, a TO that is several systems away may not know and may not be able to ascertain that information from the data in the public report on the disturbance. This is because the public report may "blind" facility descriptions for security purposes. Since NERC staff receives all the reports in their full confidential format, they will be assigning a "yes" or a "no" to this information if the TO simply does not know or cannot find out.

2.4.6. Event Type Number

As discussed in Appendix 2, each Event ID Code will have an Event Type Number assigned to it that describes the type of outage. Initially, only the five event type numbers shown below will be used, and the reader may correctly conclude that the limited Event Type Numbers shown below could be derived from data inputted elsewhere in TADS by the TO.

However, the Event Type Number structure is intended to be expanded to capture other types of Events such as whether the Element outage was accompanied by delayed clearing of a circuit breaker. This information will be valuable for transmission planners who consider appropriate contingencies in their planning process, which is why these events reference the transmission planning (TPL) standards. A list of possible future Event Type Numbers can be found at http://www.nerc.com/~filez/tadstf.html.

Event Type Numbers and the Associated Outage Description

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)

[7] EOP-004 is available at: http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

[8] The OE-417 is available at: http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

[9] Although Canadian regulatory authorities have not yet approved this standard (or any of the other recently FERC-approved standards), their approvals are expected.

2.4.7. Confidentiality

We agreed that data submitted by TOs would be classified as confidential in accordance to NERC and RE confidential information policies, and that NERC and the REs would abide by their confidential information policies, including procedures that address a request for the release of confidential information.[10] In addition, TADS public reports will not inadvertently release confidential information by the display of regional or NERC information from which a TO's confidential information could be ascertained. For example, if the TO in a region is the only owner of assets in a particular Voltage Class, the metrics on that data would not be released if the TO's name and its confidential information could be identified.[11] The exception is if the TO voluntarily provides NERC permission to do so, which NERC will seek. However, if the identity of the TO in the previous example could not be identified in a NERC-wide report that combines the data from all reporting TOs, that report would not violate the confidentiality of that TO's data, and the NERC-wide report containing information on the Voltage Class would be released.

2.5. NERC's Authority to Require TADS Data

NERC's authority to issue a mandatory data request in the U.S. is contained in FERC's rules. Volume 18 C.F.R. Section 39.2(d) 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."

A data request of U.S. entities can be made based upon NERC's authority in this FERC rule. However, NERC will be filing a "data rule" for FERC approval to include in its Rules of Procedure within the next several months. This rule will allow for a 45-day open comment period for data requests such as TADS, which then must be approved by the Board of Trustees. The data rule is contained in draft form in the July 31-August 1, 2007 agenda for the Board of Trustees.[12]

Because the data request rule will not likely have received FERC approval in time for its use for TADS 2008 implementation, we have prepared a board package for TADS approval *as if* the data rule were in effect; i.e., we posted TADS for comments for a 45-day period and consider those comments in our final TADS submittal to the board.

Appendix 5 contains a summary of the comments received as well as our responses. Section 2.7 summarizes the changes we made based upon the comments received.

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[10] NERC's treatment of confidential information is described in Section 1500 of its Rules of Procedure found at http://www.nerc.com/~filez/rules_of_procedure.html.

[11] In this case, to not lose a TO's data that would otherwise be excluded, we will probably combine its data with the data in an adjacent Voltage Class and note that this was done in our report.

[12] The agenda is at http://www.nerc.com/~filez/botagenda-0807.html. See Item No. 11.

- Several commenters asked us to explain why TADS is necessary to implement section 215 of the Federal Power Act. We provided a response to that question in Appendix 5, Section 3.a., pages 3-5.

Since TADS is a data request pursuant to Section 39.2(d) and not a reliability standard, NERC will not be issuing any fines for non-compliance. However, a non-compliant U.S. Transmission Owner may be sanctioned by FERC since failure to provide required data a violation of FERC's rules.

2.6. Intended Uses and Limitations of Data and Metrics

Since becoming the Electric Reliability Organization, NERC has taken on the role of being an independent source of reliability performance information, thereby fulfilling one of the recommendations in the April 2004 U.S.-Canada Power System Outage Task Force Report on the August 14, 2003 blackout.[13] We believe that the greatest use of TADS data will be for outage cause analysis and outage Event analysis. Event analysis will aid in the determination of credible contingencies and will result in better understanding, and this understanding should be used to improve planning and operations. Ultimately, these improvements should result in improved transmission system performance. In addition, trending each Regional Entity's performance against its own history will show how that region's performance is changing over time. It will take a number of years of data collection (five years was suggested by several commenters) before the data can be useful for trend analysis. A through-time comparison is appropriate for evaluating a region's performance. However, because regional metrics will be published, regional comparisons by others are inevitable. Given the vast physical differences between regions and TOs (weather, load density, geography, growth rate, system age, customer mix, impact of significant events, average circuit mileage, etc.), we believe that comparisons for the purposes of identifying relative performance between regions are not appropriate.

2.7. Comments That Resulted in TADS Changes

We appreciated the responses by the 33 entities that provided comments. Each comment was evaluated and discussed by the TF. For the comments that were not accepted, we explain our reasons in Appendix 5. Others made comments that were favorable and supportive of TADS or comments that did not require a response. We did not respond to those comments. However, several comments uncovered areas that we had not considered.

a. <u>Report and Manual Clarification/Corrections</u>: Several comments were addressed by adding clarifications or correcting minor errors in this revised report or the updated Data Reporting Instruction Manual. We do not view these as TADS changes but instead as improvements in our key documents.

b. <u>Phased Implementation of Initial and Sustained Outage Cause Codes</u>: Several participants expressed difficulty in providing both Cause Codes in 2008. These

[13] See *Reporting of Electric Reliability Information by Canadian Entities Re: Recommendation 10 of the U.S.-Canada Power System Outage Task Force Report* by the National Energy Board, August 2007. It can be downloaded at http://www.nerc.com/~filez/blackout.html.

commenters could provide at least one category of Cause Codes. One commenter was WECC, and given its size, we agreed to a phased implementation of both Cause Codes.

c. New Data Input: WECC posed a question regarding reporting outages of circuits that are on common structures with circuits owned by a different TO. This required a new input and additional procedures.

d. Definition Changes: We modified several definitions in direct response to comments:

   i. "Automatic Outage" was modified.

   ii. We expanded the Failed Equipment Cause Codes so that the category of failed equipment is identifiable.

   iii. We clarified that incorrect relay setting should be classified as "Human Error."

   iv. We made "Vegetation" Cause Code definition consistent with the vegetation management standard exceptions in FAC-003-1.

Appendix 5 has our complete response to comments.

2.8. TADS Beta Test

Four Transmission Owners affiliated with different TADSTF members provided TADS data for the period from July 1, 2006 through December 31, 2006. The objective of the Beta test was to perform a trial run of actual implementation.

We also decided to compute the standard metrics in Appendix 4 of this report. In the process, we found that the formula for Mean Time Between Failures (MTBF) had an error, and that the units described on two other metrics in Appendix 4 (SODT and MTTR) were also in error. Those have been corrected.

We discovered that the Event ID Code was being misinterpreted as being unique for each outage as opposed to each Event, which may involve one or more outages. Therefore, we decided to add an Outage ID Code that would be unique to each outage, and add better instructions. Also, since the description of each Event Type Number uses the term "normal clearing," we added a definition of "Normal Clearing," using the NERC Glossary definition. Finally, we added another Outage Initiation Code: Other Element-Initiated Outage. This code was just missing in the original data specification.

Some of the reported data also revealed areas for improvement in TADS. For example, of the 11 of the 21 sustained outaged reported by all four companies had "Failed Equipment" as the Sustained Cause Code. This observation supported the comments we received from posting TADS that we should expand the Failed Equipment Cause Code.

We also found a higher than expected number of Dependent and Common Mode Outages as shown the table below:

Outage Mode Codes*	Co. A	Co. B	Co. C	Co. D	Total
Single Mode	3	3	1	3	10
Dependent Mode	2	3	2	0	7
Common Mode	0	2	2	0	4
Total	5	8	5	3	21

*Sustained Outages Only

Because of the small sample, we could not make any conclusions on this information. After we have made the first analysis of 2008 partial year data (due on May 30, 2008), we may recommend modifying TADS to determine which of the Dependent and Common Mode Outages are "by design." From an operating and transmission planning perspective, if the protection system is designed so that to isolate a single element it also isolates (outages) another element, the second element's outage must be considered as a normal consequences of the loss of the single element. In this scenario, the second outage is an *intended* Dependent Mode Outage ("by design") as opposed to an *unintended* Dependent Mode Outage.

3. Required Phase I Element Inventory and Outage Data

Data will be submitted to NERC in a process described in Section 5. Data input forms are not contained in this report, but are incorporated in an updated Phase I TADS Data Reporting Instruction Manual document.

3.1. General Data

a. The name of the TO and its Regional Entity (RE). TOs with facilities in multiple REs will report data separately for each RE.
b. The TO's contact person and contact information.
c. For all tie lines and jointly-owned facilities, the name of the TOs which own each facility (or a single TO if a facility such as a tie line is owned by one entity), and the name of one TO that will be responsible for TADS reporting on each facility. This requirement assures that a single TO is responsible for reporting. We expect TOs to mutually agree on who should report these facilities.

3.2. Element Inventory Data

For each Voltage Class of Elements, the following data will be reported:

3.2.1. For All Elements

a. Year-end data on the number of Elements installed.
b. The number of Element additions and retirements during the year.
c. The weighted average % of the year that added and retired Elements are installed on the system. This will allow more accurate computation of the average annual Element population for calculating metrics.
d. The number of Elements with zero outages during the year.

3.2.2. Additional Data for AC and DC Circuits

In addition to identifying AC and DC Circuit data by Voltage Class, it will also be provided by separate Overhead and Underground Circuit categories.

a. The number of Circuit Miles at year end, including the weighted average % of the installed Circuit Miles associated with circuits that are added and retired during the year.
b. For Overhead AC Circuits that occupy common structures with other AC, the number of Multi-Circuit Structure Miles at year end, including the weighted average % of the installed Multi-Circuit Structure Miles associated with circuits that are added and retired during the year.
    i. For common structures that carry circuits owned by different TOs, we expect the TOs to coordinate with each other on their reporting of Multi-Circuit Structure Miles so that no double counting takes place. As an example, suppose two circuits owned by different TOs occupy common structures for 10 miles. For this section, the combined number of Multi-Circuit Structure Miles reported by the TOs should not exceed 10. We do not want each TO to report 10 miles since that would double count the miles for the region.

ii. We do not require this data for DC Circuits. Instead, we assume (as it the case for all Overhead DC Circuits now in existence) that two single-pole circuits occupy common structures. Therefore, the number of Multi-Circuit Structure Miles for DC Circuits is equal to one-half of the Circuit Miles.

3.3. Element Outage Data

For each Element outage, the following data will be reported:

a. Several Element descriptors. Element descriptors include:
   i. The type of Element. Was it an AC Circuit, Transformer, etc.?
   ii. The Element's Voltage Class.
   iii. 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, an optional TO Element Identifier, which permits the TO to enter an alphanumeric name of the Element (such as a circuit number) for its own use, is provided.
   iv. For AC or DC Circuits, whether it is an Overhead or Underground Circuit.
b. An Outage ID Code. This is a unique outage code assigned by the TO.
c. An Event ID Code. An Event is a transmission network incident that results in the Sustained or Momentary outage of one or more Elements. Each TO may assign its own Event ID Code. Data for each Event ID Code is described in Section 3.4.
d. The Fault Type. Several selections are available:
   i. There was no target because no fault occurred
   ii. The fault had a phase target(s) (i.e., phase-to-phase fault(s))
   iii. The fault had a ground target(s) (i.e., phase-to-ground fault(s))
   iv. The fault had both a phase(s) and a ground target(s)
   v. Unknown target(s).
e. An AC Multi-Owner Common Structure Flag. This flag only applies to outaged AC Circuits. TADS will be computing the frequency of common outages (Event Type Number 30) for circuits on common structures. In some cases, common structures can contain circuits owned be different TOs. This flag has two possible inputs:
   0 Not applicable. Circuit is not on common structures with other circuits, or the circuit is on common structures, but all circuits are owned by the same Transmission Owner.
   1 Circuit is on common structures with another circuit that is owned by a different Transmission Owner.

   For the last category (flag equal "1"), 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.
f. An Outage Initiation Code. The Outage Initiation Codes describe *where* an Automatic Outage was initiated on the power system. Five Outage Initiation Codes are available:
   i. Element-Initiated Outage
   ii. Other Element-Initiated Outage
   iii. AC Substation-Initiated Outage

iv. AC/DC Terminal-Initiated Outage
v. Other Facility-Initiated Outage

g. 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. By recording in UTC, all NERC-wide outages will have a common time stamp not dependent upon local time zone borders or local daylight savings time rules. A common time reference will allow REs and NERC to assign common Event ID Codes to Events that cross TO and RE boundaries.
h. The Outage Duration (for Sustained Outages only), rounded to the nearest minute. Momentary Outages shall be recorded as zero minute outage duration time to avoid confusion in rounding to the nearest minute.
i. A Cause Code. Eighteen Cause Codes are defined. Sustained Outages require two Cause Codes: (i) an Initiating Cause Code that that describes the initiating cause of the outage and (ii) a Sustained Cause Code that describes the cause that contributed to the longest duration of the outage. For example, 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. Momentary Outages do not have a Sustained Cause Code.[14]
j. The Outage Mode Code which describe whether an Automatic Outage is related to other Automatic Outages. Several Outage Mode Codes are provided:
   i. A Single Mode Outage is an Automatic Outage which occurred independent of any other outages (if any).
   ii. A Dependent Mode Initiating Outage is a Single Mode Outage that initiates one or more subsequent Automatic Outages.
   iii. A Dependent Mode Outage is one that occurred as a result of an initiating outage, whether the initiating outage was an Element outage or a non-Element outage.
   iv. A Common Mode Outage is 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).
   v. A Common Mode Outage Initiating Outage is a Common Mode Outage that initiates one or more subsequent Automatic Outages.

3.4. Event ID Code Data

For each Event ID Code, the following data will be reported:

1. The Event Type Number. This was previously described in Section 2.4.6.
2. Whether the Event was associated with the filing of a disturbance report under the current version of EOP-004. As described in Section 2.4.5, the TO may select

[14] 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 of Sustained, must be supplied for a Sustained Outage. See page 9 in the definitions in Appendix 2.

"yes, "no," or "unknown." To assist TOs with this question, NERC will be posting a list of year-to-date filed EOP-004 disturbance reports with public (i.e., non-confidential) data.

4. Phase I Metrics and Data Analysis

Although the term metrics and statistics have the same meaning in this report, we prefer the term "metrics" because it reflects the intent of TADS to measure performance. As described in Section 5.2, NERC in the process of completing a request for proposals (RFP) for the development of a TADS software data system for processing the metrics described below. [15]

a. 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.

b. 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.
    1. Outage frequency per Element (Sustained, Momentary, and total).[16]
    2. For AC and DC Circuits, outage frequency/100 Circuit Miles (Sustained, Momentary, and total). In addition, we will be computing the number of multiple circuit outages described by Event Type Nos. 30 and 40 per 100 Multi-Circuit Structure Miles for Overhead AC and DC Circuits.
        i. We will supplement the "per 100 mile" calculations with calculations that will remove outages not related to circuit mileage.
    3. For Sustained Outages:
        i. Outage Duration per Element.
        ii. Mean Time Between Failures –MTBF.
        iii. Mean Time to Repair – MTTR.
        iv. Median Time to Repair – MdTTR.
    4. Percent Availability.
    5. Percent of Elements with zero outages.
    6. Percent of Element outages that were associated with a disturbance report.

    Appendix 4 shows the equations for the metrics described above.

c. Because planned outage data are not part of the TADS data, the definitions of MTBF and Percent Availability will be slightly overstated from industry definitions. Appendix 3, Section 2, contains an analysis of this impact.

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[15] For 2008, NERC has budgeted funds for a full-time TADS manager, one-half of a technician, and $150,000 for software costs.

[16] Outages that qualify for an Event Type 30 and 40 classification are included in these outage frequency calculations

5. Data Collection, Analysis and Reporting Process

5.1. Required Reporting Entities

We expect the TADS reporting requirements to be made mandatory on all TOs that are registered on the NERC Compliance Registry. In addition, although TADS will be a NERC-wide requirement, REs may adopt more detailed reporting requirements. A TO may designate another entity, such as an RTO, to assume the TO's reporting obligation, provided that the designated entity and the TO jointly register with NERC per the requirements of the NERC Rules of Procedures sections 501.1.2.7 and 507. Otherwise, the TO with the reporting obligation is ultimately responsible for ensuring the timely and accurate reporting of data.

5.2. TADS Data Entry and Analysis Software

We are in the process of completing a request for proposals (RFP) for the development of a TADS software data system to support data entry, data management, and data analysis and reporting. We expect to issue the RFP in late October, with the expectation that the system will be available of receiving data by mid-March 2008.

5.3. Overall Process

We recommend the process shown on the diagram in Figure 5.0. It has three major steps that are highlighted (the large figures containing an A, B, or C). For TADS data submitted by TOs to be comparable, the consistent implementation of TADS across all TOs is critical. Therefore the process is designed to have NERC and REs work in a cooperative fashion throughout the process.

5.3.1. Data Request Process

Part “A” shows the data request process. NERC will request TADS data from each Regional Entity. Each Regional Entity may add transmission availability data requests that are applicable to their region. This bundled data request (NERC data plus RE data) will be sent from the each Regional Entity to the Transmission Owners in their region.

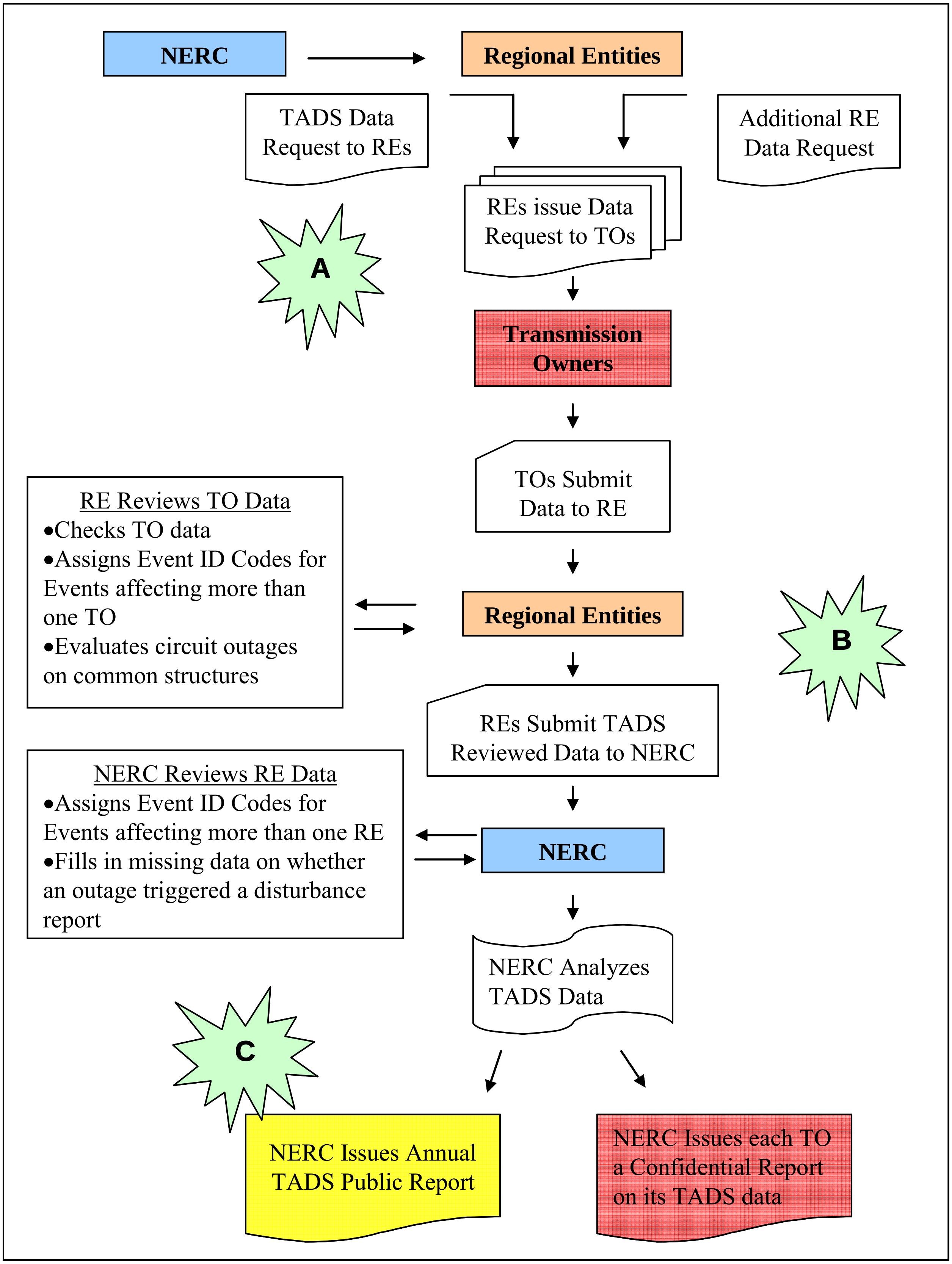
5.3.2. Data Submittal and Review

Part “B” shows the data submittal and review process. Transmission Owners submit their completed data to their Regional Entity, who do high-level data checking.

1. REs will also examine the Event ID Code data submitted by TOs and assign a common Event ID Code to Events that cross TO boundaries (if any). Common Events will be identified by near coincident Element outage start times, terminal information (for circuits only), and comments provided by the TOs.
2. RE’s will also examine AC Circuit outages that occur a common structure with multiple owners to determine the proper Event Type Number assignment

REs will then submit the TADS portion of the checked data to NERC. NERC will review RE Event ID Code data and assign a common Event ID Code to any Events that

Figure 5.0: TADS Process



cross RE boundaries. In addition, NERC will research EOP-004 disturbance reports to fill-in any data for outages that TOs have recorded as "unknown" with respect to whether the Event was associated with a reported disturbance.

5.3.3. Analysis and Reporting

Part "C" shows the analysis and reporting process. NERC will analyze the TADS data and submit a public annual report. This report will contain metrics for each Regional Entity as well as for NERC as a whole. In addition, it will provide each Transmission Owner a confidential report with the data and metrics of their system. Not shown are possible analyses by REs. If they required additional transmission data to be reported, they could analyze their region's TADS data plus the additional transmission data.

5.3.4. Role of the Regional Entities

As previously described, the process involves a coordinated effort between NERC and the Regional Entities. We view this coordination as critical to the success of TADS. We expect Regional Entities to:

- Request data from TOs.
- Review tie-lines and jointly-owned facilities to ensure that a single TO is responsible for TADS reporting.
- Review inventory and outage data for consistency and completeness (but do not review a TO's source data).
- Assign common Event ID Codes for Events affecting more than one TO in their region.
- Evaluate AC Circuit outages on common structures when the circuits are owned by different TOs.

5.4. Timetable

5.4.1. TADS Training and TADS Help

We are planning three training sessions to familiarize TOs with the new reporting requirements. These sessions will be held from November 2007 through February 2008. Training material will be posted. A NERC staff member will be assigned to respond to questions from TOs.

5.4.2. 2008 Reporting Year

Since the start-up year will be 2008, we developed a timetable that would attempt to catch any fundamental design or implementation issues early rather than wait until year-end. Since data review and processing may take six-months to complete, identifying 2008 problems in mid-2009 would not allow time to correct these problems for the 2009 data submittal. With that in mind, we recommend the timetable below for 2008. This timetable includes a two-part submittal of 2008 data with an interim NERC report on first quarter 2008 data. REs will submit a bundled data request to TOs by mid-November of 2007.

Phase I TADS Timetable for the 2008 Reporting Year

Date	Item
Late October 2007	NERC issues data request to REs if board approve TADS.
Mid-November 2007	REs submit a bundled data request to TOs.
December 17, 2007	REs ensure that all tie lines and jointly-owned facilities have a single TO with reporting responsibility.
May 30, 2008	TOs submit data to REs for the first quarter ending March 31. This includes inventory data as well as outage data.
July 15, 2008	REs submit data to NERC after performing an initial data review.
September 26, 2008	NERC completes an interim report on the results, after performing its data checks.
March 1, 2009	TOs submit all remaining 2008 data to REs.
Late June, 2009	NERC completes a final 2008 report on the results, after performing its data checks.

Many TOs already collect some type of transmission outage data, and these TOs will naturally be concerned with their ability to extract TADS data from existing data they now collect. Given the short start-up time associated with a 2008 implementation date, it may not be practical for TOs to modify their existing transmission outage data collection systems to extract TADS data. We therefore fully expect that supplying 2008 data may require a manual collection and extraction process. Using EIA Schedule 7 submittals for 2006 as a benchmark, we know that the number of Sustained Outages will not be large. For example, ERCOT reported 86 Sustained Outages for 2006 while SPP reported 101 outages.

5.4.3. 2009 Reporting Year

Starting with the 2009 reporting year, we recommend the timetable below. Since this will be a normal reporting year, it omits the two-part submittal of data and the interim NERC report that are in the 2008 schedule.

Phase I TADS Timetable for 2009 Reporting Year

Date	Item
Mid-December, 2008	REs reconfirm that all tie lines and jointly-owned facilities have a single TO with reporting responsibility.
March 1, 2010	TOs submit data to REs for the reporting year of 2009.
Mid-April, 2010	REs submit data to NERC after performing an initial data review.
Late June, 2010	NERC completes a final 2009 report on the results, after performing its data checks.

5.5. Data Access Policies

As discussed previously in Section 2.4.7, NERC will maintain all confidential data submitted to it in accordance to Section 1500 of its Rules of Procedure, and access by others will be limited by the provisions of Section 1500. However, the TADS software will be designed to allow a TO, by the use of queries, to examine and compare its specific performance aspects to the aggregate performance of all TOs in the region. For example, a TO may want to know how its lightning-caused Sustained Outage Hours per AC Circuit compare to all TOs in the region. The regional data will be aggregated as described in Section 2.4.7 so that no other TO's individual data could be obtained by the TO making the query.

6. Future Role of the TADSTF

A "task force" under NERC's parlance is a subgroup that's formed to address a specific issue. When that issue has been addressed, a task force is typically dissolved. However, we believe that the TADSTF's scope merely needs to be updated to reflect its new focus on Phase I implementation and the development of Phase II TADS. The TF's membership, who has worked well together, would remain intact.

In its redefined role, the TF's scope would include such tasks as:

- Supporting start-up and implementation
- Supporting NERC staff training of TOs
- Coordinating implementation with TOs and REs
- Recommending Phase I TADS improvements
- Recommending a Phase II TADS program, with definitions, metrics, and implementation details
- Developing the format for NERC public reports as well as confidential TO reports

7. Next Steps

Although we have accomplished much in a short time, our work is not complete. The following list describes the remaining milestones we envision. A tabular schedule of future activities for Phase I and Phase II TADS is shown below.

a. Data Reporting Instruction Manual. We are targeting the completion of an updated Phase I TADS Data Reporting Instruction Manual by October 17, 2007. This manual which will be aimed at providing TOs with information and examples to assist them in implementation. We did not seek Planning Committee or board approval for this document since it will be focused on implementation details and not policy issues.

b. Issue RFP for TADS Software. Assuming board approval, we will issue an RFP for the TADS data entry and analysis software.

c. Notification to REs/TOs. If board approval is obtained, we will begin implementation of Phase I in late October by issuing a data request to REs. (REs may then add their specific data requests and submit a bundled request to TOs.)

d. Conduct TADS Phase I Training. Three training sessions will be targeted from mid November 2007 to February 2008

e. Development of Phase II TADS. This work was initiated in August 2007. It will be concluded in 2008 for mandatory implementation in calendar year 2009.

Phase I TADS Next Steps

Dates (2007)	Activity
October 17	Post an updated Data Reporting Instruction Manual.
October 23	Board of Trustees decides on whether to approve Phase I TADS for mandatory 2008 reporting.
Late October	Issue RFP for TADS software.
Late October	NERC issues data request to REs if board approve TADS
Mid-November	Start Phase I TADS training.

Phase II TADS Next Steps

Dates (2008)	Activity
Late February	TF will issue a report to the Planning Committee recommending the details of Phase II for approval at its March 2008 meeting.
March	Planning Committee meeting to review and approve Phase II TADS.
Early April	TF will post its Phase II final report, as modified with the Planning Committees' recommendations in March 2008, and its updated Data Reporting Instruction Manual for comments (45 days).
Early July	Submit updated Phase II final report (including comments received and our response to them) to the Board of Trustees for approval at its August meeting.
August	Board of Trustees decides on whether to gives Phase II TADS its approval for mandatory 2009 reporting.

Appendix 1 Letter Announcing the TADSTF

The letter announcing the TADSTF follows.

North American
Electric
Reliability
Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5721
www.nerc.com • 609-452-8060 (Voice) • 609-452-9550 (Fax)

October 27, 2006

TO: PLANNING COMMITTEE

Transmission Availability Data System Task Force

Dear Members:

The purpose of this letter is to announce that on October 24, 2006, the Planning Committee (PC) Executive Committee formed the Transmission Availability Data System Task Force (TADSTF). The scope of the task force is attached. Jean-Marie Gagnon of Hydro Québec will chair this task force.

Transmission availability data is critical in assessing the performance of the transmission system, and many companies are already collecting such data. In Canada, the Canadian Electricity Association collects and compiles very detailed data from members who provide it. In the United States, the Energy Information Administration added Schedule 7 in its Form 411 that requires the reporting of very sparse data. No common framework now exists for collecting transmission availability data, and this is the essential issue that the TADSTF will address.

We would like to have the task force members selected by Friday, November 3, 2006 and are soliciting volunteers from the PC to work on this very important effort. The task force will start work immediately and will report their progress to the PC at its December 2006 meeting in Houston. The members will tackle the first goal described in the "Purpose" section of the scope document: to propose the type of transmission availability data that transmission owners will report to NERC.

If you would like to serve on this task force, please send an e-mail to Jean-Marie Gagnon (gagnon.jean-marie@hydro.qc.ca) and copy John Seelke of the NERC staff (John.Seelke@nerc.net).

Sincerely,

Scott M. Helyer

Scott M. Helyer
Chairman
NERC Planning Committee

Attachment
cc: Operating Committee

Transmission Availability Data System (TADS) Task Force

Purpose(s)	In order to quantify or measure system performance and reliability, the TADS Task Force will recommend: a. The <u>type</u> of transmission availability data that transmission owners will report to NERC; b. A single <u>process</u> for collecting such data that avoids duplication of effort; c. The transmission availability <u>statistics</u> that would be calculated from the reported availability data; and d. <u>Guidelines</u> for release of such data and statistics.
Background	At its December 2005 meeting, the Planning Committee (PC) created a Transmission Availability Task Force (TF) to determine what transmission performance characteristics are currently being collected and by what industry participants, the use of the data in terms of reports or other applications, and to proposed next steps for the Planning Committee to pursue. It was recognized that such data was needed to quantify or measure system performance and reliability. The task force reported back to the PC at its March and September 2006 meetings. They recommended that NERC take on the role of directing a comprehensive data collection and reporting process and that a new task force be created to define what data should be collected, the format for collecting it, and the statistics that should be reported. The task force also recommended that the new task force's efforts be expedited so as to have an opportunity to affect the current transmission availability reporting requirements of the United States Energy Information Administration.
Scope of Activities	a. Catalog the type of transmission availability data currently being collected by NERC members as well as the uses of the data. b. Recommend a common data reporting framework or protocol. c. Develop common availability statistics that could be computed from the data. d. Recommend guidelines for the sharing and release of data.
Membership	Five to ten people, including members of the Planning Committee as well as industry experts.
Reporting	Responsible to the NERC Planning Committee.
Subgroups	NA

Appendix 2 TADS Definitions

A separate definitions document follows.

NERC

Transmission Availability Data System (TADS)

DEFINITIONS

September 26, 2007

Table of Contents

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

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. See the Transformer exclusion in "In-Service State."

The boundary of an AC Circuit extends to the transmission side of an AC Substation. The circuit breaker or disconnect switch 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.

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, shunt or series capacitors, and reactors. 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.

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[1] This definition is in the current NERC Glossary of Terms.

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.)

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.

B. Outage Reporting Definitions

1. Automatic Outage

An outage which results from the automatic operation of a switching device, resulting in a normally in-service Element that is not in an In-Service State; i.e., there is a partial or full loss of continuous power flow through the Element to the system. 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:[2]

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

4. 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 owned 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 owned 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.

5. In-Service State

An Element that is energized and fully connected to the system. An exception is provided for a multi-terminal AC Circuit with a Transformer on one terminal. In this case, as illustrated below, the circuit is considered to be in an In-Service State even though Transformers and their associated switching or interrupting devices are not in service.

[2] The TADS definition of Sustained Outage is different that the NERC Glossary of Terms definition of Sustained Outage which is presently only used in FAC-003-1. The NERC Glossary of Terms 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 NERC Glossary of Terms definition.

The illustrations below indicate the special handling of Transformers as they relate to a multi-terminal AC Circuit outage.

Figure 1

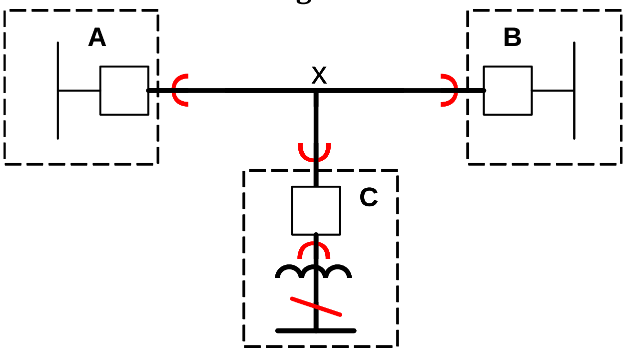
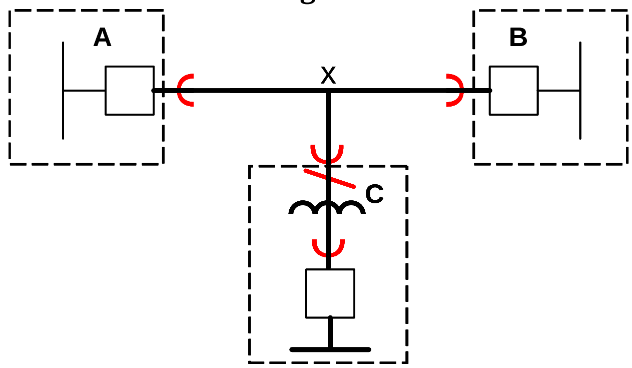


Figure 2



In both figures, the AC Circuit is bounded by AC Substations "A," "B," and "C" as indicated by the red arcs. The 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). For the multi-terminal exception, this difference does not matter.

Assume that each Transformer is out of service. Power cannot flow through the portion of the AC Circuit from "x" to Substation C because of the Transformer outage. 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.

6. **Substation, Terminal,** or **Converter Name**

For 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.

7. TO Element Identifier

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

8. 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.

9. Outage Duration

The amount of time from the Outage Start Time to the when the Element is fully restored to 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 a Sustained Outage that starts in one calendar year and concludes in another calendar year.

10. Outage Identification (ID) Code

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

11. Event

An Event is a transmission incident that results in the Sustained or Momentary outage of one or more Elements.

12. 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 Automatic 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.

13. 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 direct 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)

Event Type No. 30 and 50 Examples

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 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 were 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 first circuit's breaker failed 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.

14. Fault Type

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

1. There was no target because no fault occurred
2. Phase target(s) (i.e., phase-to-phase fault(s))
3. Ground target(s) (i.e., phase-to-ground faults(s))
4. Both phase target(s) and ground target(s)
5. Unknown target(s).

15. 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.[3]

[3] This definition is in the current NERC Glossary of Terms.

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.

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

A Single Mode Outage that initiates one or more subsequent 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.

Initiating and Sustained Cause Code Examples

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.

Special Exception for 2008 Reporting: 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, 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.

Appendix 3 Planned Outage Data Collection Analysis

1. Pros and Cons of Collecting Planned Outage Data

The table below summarizes some of the pros and cons regarding the collection of planned outage data.

Collect Planned Outage Data Because:	Don't Collect Planned Outage Data Because:
Most utilities collect planned outage data so little or no additional burden is imposed by requiring it to be reported. Without planned outage data, transmission system availability cannot be calculated, and a trend of this statistic is a useful indicator.	Trending system unavailability has a potential negative unintended consequence. Since planned outages comprise the largest part of unavailability, a Transmission Owner could maximize system availability by (a) reducing planned outages, which could (b) increase forced outages but (c) meet a goal of increased availability. The EPRI Grid Reliability project found that planned outages were reported as less attainable through participant surveys than forced outages.
Planned outage data captures the amount of maintenance performed. With planned outage data, the relationship between planned and forced outages can be shown; i.e., more planned outages should reduce forced outages.	Planned outage data doesn't capture live-line maintenance. Planned outages are subject to many Transmission Owner variables (weather, crew availability, and budgets) so true comparisons cannot be made.
Planned outage data allows a Transmission Planner to correlate historical planned outage data and load data and thus be able to implement TPL standards.[17]	Planned outages are only allowed when system conditions permit them and therefore do not jeopardize reliability.

The added burden of collecting planned outage data can be approximated by examining the number of planned outages that will be reported versus the number of forced outages that will be reported. Therefore, we examined reported Schedule 7 data for the year 2006 in EIA Form 411.[18] Schedule 7 contains transmission outages data for AC circuits ≥230 kV as well as data for DC circuits. We analyzed AC circuit data only since it was the most abundant. Regions that reported Schedule 7 data for 2006 included:

- Reliability First Corporation
- Midwest Reliability Organization
- Southwest Power Pool
- Partial data for NPPC: the New England sub-region of NPPC and 500 kV data for Ontario

[17] As an example, TPL-003-0, Requirement R1.3.12, states:
Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

[18] The U.S Energy Information Administration's Form 411 can be found at http://www.eia.doe.gov/cneaf/electricity/page/forms.html

EIA's definition of a scheduled (i.e., a planned) outage excludes all outages that are one hour or less in duration. EIA's definition of unscheduled outages excludes all outages that are less that one minute in duration. Thus, it excludes Momentary Outages, which is consistent with the TADS definition of Sustained Automatic Outages. However, EIA's unscheduled outage definition has some minor exclusions which are not in the Sustained Automatic Outage TADS definition. While EIA unscheduled outages does not precisely match what TADS will collect for Sustained Automatic Outages, it is close.

The results are shown on the below. In EIA's framework, an EIA "outage" may involve multiple circuits. In the TADS framework, an outage involves only one circuit (or element).[19] EIA also reports the number of circuit outages, which would be comparable to a TADS outage. However, in reviewing that data, it was apparent that some respondents may have recorded a circuit that was involved in several outages only once for the circuit outage data that was submitted. For this reason, the data for the number of scheduled and unscheduled outages was used.

Comparison of Scheduled and Unscheduled Outages Using 2006 Schedule 7 Data

Applicable A.C. Voltage Class	230 kV	345 kV	500 kV	765 kV
No. of Scheduled Outages	1108	1516	205	72
No. of Unscheduled Outages	1131	640	62	14
Ratio Scheduled/Unscheduled	0.98	2.37	3.31	5.14

Depending upon the voltage level, the number of planned outages can easily increase the reporting requirements by a factor of two or more. For example, 230 kV circuits had about the same number of planned and forced outages in 2006 (1108 and 1131, respectively), so the number of reported outages would almost double if planned outages are included.

2. Impact on Metrics of Excluding Planned Outages

The metrics reported by TADS comply with normal industry usage with two exceptions: the definitions of Percent Availability (PA) and Mean Time Between Failures (MTBF).

- Since Momentary Outages are assumed to have zero outage time, they do not enter into the calculation of these metrics.
- The calculation assumed two categories for outages: Automatic Outages and all other outages which are referred to as "planned outages." Since planned outages were excluded, no TADS definition was developed for this term.

The difference in the normal definitions for PA and MTBF and the TADS definitions is shown below.

[19] In the TADS framework, an Event, which describes the outage of one or more elements, would be comparable to the EIA term for an "outage."

1. Percent Availability:

    a. Normal Industry Definition:

    [(No. of Elements x 8,760 hrs) – Σ Element Sustained Automatic Outage Hours - Σ Element Planned Outage Hours] / (No. of Elements x 8,760 hrs)

    b. TADS Definition:

    [(No. of Elements x 8,760 hrs) – Σ Element Sustained Automatic Outage Hours] / (No. of Elements x 8,760 hrs)

2. Mean Time Between Failures

    a. Normal Industry Definition:

    [(No. of Elements x 8,760 hrs) – Σ Element Sustained Automatic Outage Hours - Σ Element Planned Outage Hours] / (No. of Sustained Element Outages)

    b. TADS Definition:

    [(No. of Elements x 8,760 hrs) – Σ Element Sustained Automatic Outage Hours] / (No. of Sustained Element Outages)

To determine the impact of excluding planned outage data in the calculation of these metrics, we examined reported EIA Form 411 Schedule 7 data for the year 2006 which was previously described in Section 1 of this Appendix.

Schedule 7 does not require reporting of the total number of circuits in a voltage class, but it does require reporting the number of circuits with scheduled outages as well as the number of circuits with unscheduled outages. Therefore, as an estimate for the total number of circuits we used the greater of the two reported values. For example, for 345 kV circuits, ERCOT reported 472 circuits involved with scheduled outages and 89 circuits with unscheduled outages. We therefore used 472 circuits in our calculations as the total number of 345 kV circuits. We also assumed these circuits were installed for the entire year.

The results are shown below. Since both scheduled and unscheduled outages are relatively small percentages of circuit in-service time, the impact on the Percent Availability and MTBF metrics is very small if planned outages are excluded.

Comparison of Outage Metric Calculations Using 2006 Schedule 7 Data

Applicable A.C. Voltage Class	230 kV	345 kV	500 kV	765 kV
Total No. of Circuits (est.)	1021	672	48	23
% Scheduled Outage Hrs. to Total Circuit Hrs.	0.429%	1.137%	0.796%	2.471%
% Unscheduled Outage Hrs. to Total Circuit Hrs.	0.351%	0.120%	0.351%	0.880%
Percent Availability w/o Scheduled Outages	99.649%	99.880%	99.649%	99.120%
Percent Availability with Scheduled Outages	99.220%	98.743%	98.852%	96.649%
MTBF w/o Scheduled Outage Data (hrs.)	11,346	16,665	13,235	18,606
MTBF with Scheduled Outage Data (hrs.)	11,297	16,475	13,129	18,142

Appendix 4 Metric Formulas

General Formulas

No.	Metric	Formula	Units	Acronymn
	Element Outage Frequency			
1	Element Total Automatic Outage Frequency	Total Automatic Outages / Total Elements	No. Automatic Outages per Element per year	TOF
2	Element Sustained Outage Frequency	Total Sustained Outages / Total Elements	No. Sustained Outages per Element per year	SOF
3	Element Momentary Outage Frequency	Total Momentary Outages / Total Elements	No. Momentary Outages per Element per year	MOF
	Element Outage Duration, Repair Time, and Up Time			
4	Element Sustained Outage Duration Time	Total Sustained Outage Hours / Total Elements	Average no. of Sustained Outages Hours per Element per year	SODT
5	Element Sustained Outage Mean Time to Repair	Total Sustained Outage Hours / Total Sustained Element Outages	Average no. of Sustained Outage Hours per outaged Element	MTTR
6	Median Time to Repair Sustained Element Outage Failures	The time when 50% of the Mean Time to Repair minutes are greater than this figure	Median no. of Sustained Outage Hours per outaged Element	MdTTR
7	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]
	Element Availability			
8	Element Availability Percentage	1- (Total Sustained Outage Hours / Total Element Hours) * 100	Percentage	APC[1]
9	Percentage of Elements with Zero Automatic Outages	Total Elements with Zero Automatic Outages / Total Elements	Percentage	PCZO
10	Percent of Element Automatic Outages associated with a Disturbance Report (EOP-004)	Total Automatic Outages associated with a Disturbance Report / Total Automatic Outages	Percentage	PCDR

1 Since planned outage data are not collected, these metrics will be slightly overstated from industry definitions. See Appendix 3, Section 2, for a discussion of the impact.

General Formulas (cont'd)

	Metric	Formula	Units	Acronymn
	Circuit Outage Frequency, per 100 Circuit Miles (Applies to AC and DC Circuits Only)			
11	Circuit Total Outage Frequency, Mileage Adjusted	(Total Circuit Automatic Outages *100) / Total Circuits Miles	No. Automatic Outages per 100 Circuit Miles per year	$TCOF_{100CTmi}$
12	Circuit Sustained Outage Frequency, Mileage Adjusted	(Total Circuit Sustained Outages *100) / Total Circuit Miles	No. Sustained Outages per 100 Circuit Miles per year	$SCOF_{100CTmi}$
13	Circuit Momentary Outage Frequency, Mileage Adjusted	(Total Circuit Momentary Outages *100) / Total Circuit Miles	No. Momentary Outages per 100 Circuit Miles per year	$MCOF_{100CTmi}$
	Multiple Circuit Outage Frequency per 100 Multi-Circuit Structure Miles (For AC Circuits, multi circuit outages are Event Type 30 outages; for DC Circuits, they are Event Type 40 outages.)			
14	Multi Circuit Total Outage Frequency, Mileage Adjusted	(Total Multi-Circuit Automatic Outages *100) / Total Multi-Circuit Structure Miles	No. Automatic Outages per 100 Multi-Circuit Structures Miles per year	$TMCOF_{100STmi}$
15	Multi-Circuit Sustained Outage Frequency, Mileage Adjusted	(Total Multi-Circuit Sustained Outages *100) / Total Multi-Circuit Structure Miles	No. Sustained Outages per 100 Multi-Circuit Structure Miles per year	$SMCOF_{100STmi}$
16	Multi-Circuit Momentary Outage Frequency, Mileage Adjusted	(Total Multi-Circuit Momentary Outages *100) / Total Multi-Circuit Structure Miles	No. Momentary Outages per 100 Multi-Circuit Structure Mles per year	$MMCOF_{100STmi}$

Appendix 5 TADS Comments and Responses

A report on the TADS comments and our responses follows.

Summary of and Responses to TADS Comments

September 26, 2007

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1. Introduction

The June 28, 2007 letter from David Nevius of NERC requesting comments resulted in the submittal of 33 sets of comments. The letter is in Appendix A. Comments were requested about the June 7, 2007 TADS Final Report ("Report") and the June 29, 2007 Data Reporting Instruction Manual ("Manual"). The majority (29) of the comments were filed by Transmission Owners (TOs), Transmission Operators (TOPs) or committees representing specific Transmission Owners and Transmission Operators.[1] The list of commenters is shown below. There comments are posted at http://www.nerc.com/~filez/tadstf.html.

	Commenter	TO	TOP	Other
1	American Electric Power	X	X	
2	Ameren	X	X	
3	American Transmission Co.	X	X	
4	Baltimore Gas & Electric	X	X	
5	CenterPoint Energy	X	X	
6	Duke Energy	X	X	
7	Edison Electric Institute			X
8	Energy Information Administration			X
9	Exelon	X	X	
10	First Energy	X	X	
11	Great Lakes Power	X	X	
12	Georgia Transmission Corporation	X	X	
13	Hydro One	X	X	
14	IESO (Ontario)	X	X	
15	ITCTransmission	X	X	
16	JEA	X	X	
17	KCPL	X	X	
18	Lower Colorado River Authority	X	X	
19	Manitoba Hydro	X	X	
20	National Grid	X	X	
21	Northeast Utilities	X	X	
22	Nova Scotia Power Inc.	X	X	
23	New York Power Authority	X	X	
24	Oncor Energy Delivery	X	X	
25	Pepco Holding Company	X	X	
26	Progress Energy	X	X	
27	PUD No.1 of Clallam County	X	X	
28	William Reinke			X
29	Salmon River Electric Cooperative	X		
30	SERC Vegetation Management Subcommittee	X	X	
31	Southern Co.	X	X	
32	TVA	X	X	
33	WECC Reliability Subcommittee	X	X	
		30	29	3

The letter requested comments to the six specific questions below, and most commenters followed that format. A summary of the responses is provided on the next page.

[1] The comments filed by the SERC Vegetation Management Committee and the WECC Reliability Subcommittee represent the later.

Summary of Responses to Questions

1. *If you are a Transmission Owner, do you currently collect transmission outage data similar to TADS? If "yes," please explain.* ***28 of the 29 Transmission Owners collected data similar to the data requested by TADS****.*
2. *Is the data being requested reasonable and obtainable? See Section 3 of the Report. If "no," please explain.* ***23 of the 29 Transmission Owners said "yes."****
3. *Are the metrics appropriate? See Section 4.b and Appendix 4 of the Report. If "no," please explain.* ***20 of the 29 Transmission Owners felt the metrics were generally appropriate.****
4. *Is the data reporting process reasonable? See Section 5.2 of the Report. If "no," please explain.* ***18 of the 29 Transmission Owners felt the data reporting process was reasonable.****
5. *Is the implementation schedule for Phase I TADS for 2008 reasonable? See Section 5.3.1 of the Report. If "no," please explain.* ***20 of the 29 Transmission Owners felt the Phase I implementation was generally reasonable*.***
6. *Are there ambiguities in the Manual that need clarification? If "yes," please explain.* ***Many commenters suggested changes to the data being collected or requested clarifications.****

*** Others either offered no opinion or expressed concerns about specific issues.*

2. Comments That Resulted in TADS Changes

We appreciated the responses by the 33 entities that provided comments. Each comment was evaluated and discussed by the TF. For the comments that were not accepted, we explain our reasons in this document. Others made comments that were favorable and supportive of TADS or comments that did not require a response. We did not respond to those comments. However, several comments uncovered areas that we had not considered. The following describes comments that will be incorporated in a revised Report and Manual.

a. **Report and Manual Clarification/Corrections:** Several comments will be addressed by adding clarifications or correcting minor errors in the revised Report or Manual. We do not view these as TADS changes but instead as improvements in our key documents.

b. **Phased Implementation of Initial and Sustained Outage Cause Codes:** Several participants expressed difficulty in providing both Cause Codes in 2008 (see Section 5.l in this document). These commenters could provide at least one category of Cause Codes. One commenter was WECC, and given its size, we agreed to a phased implementation of both Cause Codes.

c. **New Data Input:** WECC posed a question regarding reporting outages of circuits that are on common structures with circuits owned by a different TO. This required a new input and additional procedures, which are addressed in Section 5.o in this document.

d. Definition Changes: We will modify several definitions in direct response to comments:

i. "Automatic Outage" will be modified in response to comments from SERC VMS and TVA. See Section 5.e in this document.

ii. We will expand the Failed Equipment Cause Codes so that the category of failed equipment is identifiable. (AEP, National Grid, IESO, ITC, and KCPL). See Section 5.m.i in this document.

iii. We will clarify that incorrect relay setting should be classified as "Human Error." (Northeast Utilities, IESO) See Section 5.m.i in this document.

iv. We will make the "Vegetation" Cause Code definition consistent with the vegetation management standard exceptions in FAC-003-1. (IESO, SERC VMS, TVA) See Section 5.m.vii in this document.

3. General Comments

Several entities offered either general comments or similar comments to issues that were written under different question categories. We chose to combine these similar comments and offer a collective response to them. The comments are summarized, although some direct quotes are also provided.

a. Several comments asked us to better explain why we felt TADS was necessary and how the data would be useful. Our Report addressed this issue in Section 2.6:

> **"We believe that the greatest use of the data will be for outage cause analysis and outage Event analysis. Event analysis will aid in the determination of credible contingencies and will result in better understanding, and this understanding should be used to improve planning and operations. Ultimately, these improvements should result in improved transmission system performance. In addition, trending each Regional Entity's performance against its own history will show how that region's performance is changing over time. This through-time comparison is appropriate for evaluating a region's performance. However, because regional metrics will be published, regional comparisons by others are inevitable. Given the vast physical differences between regions and TOs (weather, load density, geography, growth rate, system age, customer mix, impact of significant events, average circuit mileage, etc.), we believe that comparisons for the purposes of identifying relative performance between regions are not appropriate."**

The comments below are all related to the central issue of why TADS is being proposed.

- **Explain why TADS is needed for NERC, as the ERO, to implement its requirements under Section 215. (FirstEnergy)**

- **"We question whether a business case has been made that this outage data reporting process will lead to improved reliability." (Duke Energy)**
- **Collecting data on transmission availability and specific outages does "not provide a direct measure of the ability of the transmission system to transmit or deliver electricity or the risk that the transmission system may pose to neighbouring systems." Therefore, it will not "add value to assessing network performance on a regional basis." (Hydro One)**
- **"All of the efforts that will go into TADS reporting will be a waste of effort for an individual transmission owner." (Georgia Transmission)**
- **Mr. Reinke stated "the collection of such information will be a burden to the industry and that the data will not provide a foundation for serious and meaningful analysis." He also objected to the EIA's current collection of data.**
- **Mr. Reinke notes that while Section Report 2.6 describes trending of a regions performance, regions do not own or operate transmission systems. "If NERC intends to measure the performance of transmission owners and operators within a region it should make that clear and not base its justification for the collection of information on false premises."**

We will address these six comments in one response.

One of the ERO's central missions is to develop reliability standards. This is a central theme of the Section 215 of the Federal Power Act which created the ERO in the U.S. Whether a new standard is needed or whether an existing standard needs to be modified, sound data is needed for this purpose. As an example, standards FAC-010 and FAC-011 address contingencies that are to be considered in determining System Operating Limits and Interconnection Reliability Operating Limits. Although these standards define contingencies that must be considered, as the ERO, we have no consistent data about what contingencies are credible and therefore proper for SOL and IROL development.

TADS data is intended to provide a basis for standards such as these. We believe this makes a compelling business case for a consistent NERC-collected database. By aggregating data from all Transmission Owners, NERC will be better equipped to address its central role of developing reliability standards.

We agree with Hydro One that information on equipment availability or specific outages is not equivalent to measuring transmission system performance or reliability. Our Report said such data "will *help* quantify system performance and reliability (emphasis added).[2]

TADS data is not intended to provide determinative performance measures, but we believe it can quantify certain performance aspects. In addition to collecting simple transmission equipment availability, TADS will collect detailed information about individual outage events that, when analyzed at the regional and NERC level, will provide data such as causes that may be used to improve reliability. We will also know whether specific equipment outages were associated load and generation outages by knowing whether they were associated with disturbance reports filed with

[2] See Report Section 2.1, first paragraph, last sentence.

NERC.[3] In addition, we will also know whether outages by one Transmission Owner are related to outages of other Transmission Owners.[4] Section 215(g) requires the ERO to make periodic assessments on the reliability of the bulk power system in North America. We view TADS data as part of the information that will be needed in meeting this obligation.

We disagree with Georgia Transmission and Mr. Reinke that TADS will not benefit individual Transmission Owners. By providing comparable outage data, TADS will allow Transmission Owners to compare their performance with the aggregate performance of TOs in their region and highlight potential problem areas, hereby paving the way to understanding the underlying cause of performance differences and using this understanding to improve reliability.

Regarding Mr. Reinke's comment regarding our phase "regional performance," that phrase was intended to mean the aggregate performance of Transmission Owners in a region, not the performance of a Regional Entity. We had no intention of misleading Transmission Owners as to the reason for TADS.

b. For trending purposes, several years of data will be required. (National Grid, IESO)

We agree that trending cannot be useful until several years of data are collected. We will state that in our revised Report.

c. Several entities asked for clarification about the intended use of TADS data.

- **JEA asked "what is the end in mind" for TADS.**
- **The SERC VMS and TVA stated "Not enough is known about the intended use of the data to know if it's reasonable."**
- **Southern asked "who the intended audience is for information reported in TADS as well as what the expectation is for "how" the information will be used."**

Section 2.6 of the Report describes the intended uses and limitation of TADS. While the public reports will be made available on NERC's Website, the intended audience the NERC community, but specifically Transmission Owners, Transmission Operators, and Transmission Planners.

d. Duke Energy stated "since this data will be intended to improve the performance of the power system by sharing outage cause information, the Transmission Owners and Operators Forum may be a better avenue for collecting and analyzing the data."

The Transmission Owners and Operators Forum is a voluntary association; therefore a comprehensive set of comparable data set cannot be developed within the forum.

e. The 200 kV cut-off was addressed by two entities.

- **Why is TADS limited to 200 kV and greater? If the data is needed, it should apply to facilities 100 kV and greater. (FirstEnergy)**

[3] The reporting requirements in reliability standard EOP-004 provide this information.
[4] See Report Section 5.2.2.

- **TADS at 200 kV and greater is manageable, but if it is expanded to the 100 kV level, much more effort will be required and we would reconsider our support. (Nova Scotia Power)**

Report Section 2.4.1 addressed the 200 kV cut-off. It was selected in part because 200 kV is used by WECC and ECAR. It also limits the scope of the start-up effort while providing NERC with a consistent framework for data collection. This same voltage cut-off is also used in the NERC Transmission Vegetation Management Program standard FAC-003-1.

f. Several entities had common concerns about the topic of confidentiality.

- **TVA expressed concern that TADS will be used to compare the performance of Transmission Owners.**
- **AEP expressed concern that, as the only owner of assets in a Region, that its metrics could be singled out in a report and asked "the metrics that could single out an entity should be classified as confidential and treated as Critical Energy Infrastructure Information (CEII)."**
- **Manitoba Hydro noted that from Figure 5 in the report (which describes the flow of information) does not identify DOE and FERC and suggests that the raw data will "never pass into other hands."**
- **Both Manitoba Hydro and Hydro One asked that NERC not release Canadian information to the FERC or EIA without approvals.**
- **EIA stated:**

> **"Granting general protection (i.e., declaring the data to be sensitive and not releasable to the public) to all individually identifiable data associated with an individual transmission owner is of major concern to the EIA. Access by Federal agencies to that detailed data may be a necessity. Until discussions are completed within the DOE and with other Federal agencies, the EIA cannot give any endorsement to this declaration should TADS become a vehicle for providing data to the EIA. The EIA does withhold or suppress certain data in its publications where those protections have been publicly commented upon and the justification has been reviewed and approved by the Office of Management and Budget. A similar examination will have to be done for any data elements proposed to be placed in this category, if EIA is to use TADS in lieu of our own data collection."**

Report Section 2.4.7 addresses confidentiality:

> "We agreed that data submitted by TOs would be classified as confidential in accordance to NERC and RE confidential information policies, and that NERC and the REs would abide by their confidential information policies, including procedures that address a request for the release of confidential information.[5] In addition, TADS public reports will not inadvertently release confidential information by the display of regional or NERC information from which a TO's confidential information could be

[5] NERC's treatment of confidential information is described in Section 1500 of its Rules of Procedure.

ascertained. For example, if the TO in a region is the only owner of assets in a particular Voltage Class, the metrics on that data would not be released if the TO's name and its confidential information could be identified. The exception is if the TO voluntarily provides NERC permission to do so, which NERC will seek. However, if the identity of the TO in the previous example could not be identified in a NERC-wide report that combines the data from all reporting TOs, that report would not violate the confidentiality of that TO's data, and the NERC-wide report containing information on the Voltage Class would be released."

Transmission Owner performance data and metrics will be kept confidential, and comparisons of TO performance will not be made by NERC. Unless a Transmission Owner approves, we will not release metrics of a TO in our reports that would display its confidential information. With respect to EIA and FERC (or other governmental authorities), their access to raw Transmission Owner data will be governed by Section 1500 Confidential Information of NERC's Rules of Procedure. With respect to EIA Form 411 data, Canadian data will not be reported to EIA without approvals.

We believe that we can address EIA's confidentiality concerns. As we stated in our Report, we see no conflict between EIA's confidential information policies and NERC's confidential information policies based on our preliminary review. If access by a Federal agency of confidential information of a U.S. Transmission Owner is necessary, we believe EIA needs can be accommodated. We now provide EIA with confidential information that is Critical Energy Infrastructure Information (CEII). As an example, transmission system maps and power flow cases provided by NERC to EIA under current Form 411 requirements and are only disclosed by EIA pursuant its confidential information policies. We welcome further discussion with EIA on this topic.

g. TVA objected to the publication of regional metrics because "regional comparisons are inevitable" as acknowledged by TADS. TVA stated that such comparisons "could impact a region's economy." TVA also supports the concept that "NERC should receive the same information submitted in the DOE EIA-411 filing."

As we stated in Section 2.6, "comparisons for the purpose of identifying relative performance between regions is not appropriate." Regional transmission metrics are already reported to the EIA in its current Schedule 7, although in much lesser detail than what TADS expects to be reporting. Such information is now available to the public.

h. Mr. Reinke objects to TADS proceeding before the data rule described in Report Section 2.5 in finalized.

NERC can proceed with TADS and board approval based upon the language in Volume 18 C.F.R. Section 39.2(d). We have followed the format of the draft data rule to obtain industry input.

i. In its transmittal e-mail, LCRA said that TADS data "should not be used for Sanction action."

TADS data is intended to be used to develop information that will improve the planning and operation of the power system. Confidential individual TO data will be accessible by REs (for TOs in their Region), and NERC staff (for all TOs submitting data). While TADS is not intended to be used as a compliance tool, data that is submitted that may indicate lack of compliance with a standard cannot be ignored by an RE or NERC.

j. **Several entities commented on topics that would be addressed in Phase II.**

- **In addition to Automatic Outages, collect Emergency/Forced Outage data. (National Grid)**
- **Do not collect planned outage data in Phase II TADS. (Baltimore Gas & Electric, CenterPoint, Duke Energy, Georgia Transmission, ITC, Manitoba Hydro, National Grid, Reinke, Southern Co., TVA, WECC-RS)**

These are both Phase II TADS issues which the TADSTF and the Planning Committee will consider in late February 2008. See the description of Phase II TADS in the Report (Section 2.3) and the Phase II TADS schedule (Section 7).

k. **NERC should consider commercial products that could support TADS. (EEI, Pepco Holding)**

TADS data requirements do not precisely match any commercial product application that we are aware of for collecting and analyzing transmission data. We will be issuing an RFP for the development of a TADS software data system to support data entry, data management, and data analysis and reporting. Existing commercial product providers are welcome to respond.

l. **NERC should consult with various entities around the country to determine how to most effectively transition the industry toward the new TADS platform and have a project plan for the implementation of TADS. (EEI, Pepco Holding) NERC should "work with industry transmission owners, industry technical experts (EPRI, IEEE) as well as current industry-wide benchmarking efforts in order to standardize the collection of and description of the data set." (KCPL)**

The TADSTF has broad industry representation. We have, therefore, considered the views of the industry as TADS was developed. The comments we have received from Transmission Owners have indicated that while TADS data and the format requested does not align with their current processes, the submittal of TADS data will generally not be too difficult.[6] In addition, most felt that the implementation schedule was not generally a problem.[7] However, since each Transmission Owner has their own system for data collection, the degree of transition effort involved will be company specific. The Report has timelines and milestones for TADS that constitute an implementation plan. Two items which are not expressly addressed in the Report are the development of TADS software and training. These will be addressed in our revised Report.

m. **If a Transmission Owner delegates its TADS reporting requirements to an RTO or ISO that has registered with NERC for that purpose, NERC should not hold**

[6] See the summary of responses to question 2 on page 2.
[7] See the summary of response to question 3 on page 2

“the TO ultimately responsible for ensuring the timely and accurate reporting of data” as described in Report Section 5.1. (EEI)

We will modify Report Section 5.1 as follows:

“A TO may designate another entity, such as an RTO, to assume the TO's reporting obligation, provided that the designated entity and the TO jointly registers~~s~~ with NERC ~~for this purpose~~per the requirements of the NERC Rules of Procedures sections 501.1.2.7 and 507. ~~However~~Otherwise, the TO with the reporting obligation is ultimately responsible for ensuring the timely and accurate reporting of data.”

4. Comments Related to the Question 1

Question 1 asked “*If you are a Transmission Owner, do you currently collect transmission outage data similar to TADS? If “yes,” please explain.”* Of the 29 Transmission Owners, 28 collected data similar to TADS. Some Transmission owners described details about their collection process. Although no one is currently collecting exactly what TADS is requesting, most collect similar types of data.

5. Comments Related to the Questions 2

Question 2 asked “*Is the data being requested reasonable and obtainable? See Section 3 of the Report. If “no,” please explain.”* The responses to these questions generally focused on specific data questions.

Most (23 out of 29) Transmission Owner’s said “yes” with respect to the reasonableness of the data being requested, although their process would need to be modified to provide the data to NERC. However, three commenters (Reinke, JEA, and TVA) had reservations about the reasonableness of the data. Their comments are addressed first.

a. JEA stated:

“[T]he data being requested in many cases is beyond reasonable and not obtainable in many cases. As an example, if our area experiences a severe lightning storm, a transmission line may experience multiple momentary operations due to lightning. Gathering each individual relay target for each momentary fault operation is not obtainable, especially if we have electromechanical targeting systems. Knowing the exact location of lightning flashover for each individual momentary fault under multiple operations may also be impossible to obtain. The causes and modes would also be difficult to obtain and unreasonable as data items, under these conditions. Even when a multiple momentary fault results in a sustained interruption, some of the requested data will be very hard to obtain. Transient events that restore to normal operation in less than 60 seconds are usually related to lightning surges that may not provide any visual or residual evidence for TADS reporting, and would require exhaustive field surveys that would be futile and distracting from the business at hand of promptly restoring service.”

We note that some of JEA’s objections are based in part on specific data being requested: Fault Type, Cause Codes, and Outage Modes. In addition, they express concern that data collection efforts may distract from the restoration of service.

Some Element outage data must be collected when an outage occurs (such as Outage Start-Time and Outage Duration). Other data can be obtained later as the outage is analyzed. However, Fault Type needs to be determined shortly after a fault occurs so that the data can be captured before another fault occurs and overrides the previous data. If multiple faults occur during a storm on the same circuit such that each Fault Type cannot be determined, "Unknown" should be checked. TADS data collection should not interfere with restoration efforts.

b. TVA stated:

> **"When viewed strictly from the standpoint of reliability reporting, fields such as 'Fault Target', 'Outage Initiation Code', 'Outage Mode', 'Event Type' (only the 'Event Type' is used in calculations of proposed metrics), and 'Disturbance Report Filed' have no apparent benefit. When viewed within the context of ongoing discussions within the NERC Planning Committee, there may be benefit to the capture of this data, but whether it rises above the cost of capture is in question."**

The reason for collecting Fault Type[8] data is addressed in a Section 5.c below. We provide the following response on the benefit of the other data questioned by TVA:

- Outage Initiation Codes tell us where the outage was initiated. We know that Element outages are not all initiated by a cause that directly impacts the Element, but are frequently initiated elsewhere on the system. Our Beta test on four companies showed that only 11 out of 21 Sustained Outages were Element-Initiated Outages.
- The Outage Mode will provide valuable information regarding how many outages occur due to a common cause or as a consequence of one another. This information will help define what contingencies are considered credible for planning and operations. Our Beta test on four companies showed that only 10 out of 21 Sustained Outages were Single Mode Outages.
- The Event Type No. 30 and 40 are used to compute outages metrics for circuits on Multi-Circuit Structures. With these two Event Type Numbers, we will collect data on whether placing two or more circuits on the same structure have a significant impact on outage frequency.
- The reason for the "Disturbance Report Filed" question is addressed our response in Section 5.a above.

c. What is the purpose of collecting Fault Type data? (ITC, TVA)

For Automatic Outages it is important to understand the Fault Type. From a technical perspective, it is desirable to identify the following fault types for each outage:

1. Balanced three phase fault current (no ground current),
2. Unbalanced three phase fault current with ground current,
3. Phase-phase-ground fault,
4. Phase-phase fault (no ground current), or
5. Single phase to ground current.

[8] Many commenters referred to this as "Fault Target," a term we used erroneously on our data input forms. We should have used "Fault Type," which is a defined term.

We debated this issue and decided for correct operations that TADS would collect a more limited set of relay targets (if any targets occurred);

1. None (no fault occurred)
2. Phase target(s) (i.e., phase-to-phase fault(s))
3. Ground target(s) (i.e., phase-to-ground fault(s))
4. Both phase target(s) and ground target(s)
5. Unknown target(s).

During a storm or emergency restoration of facilities, we are *not* is expecting a TO to immediately send personnel to the substation to record and reset relay targets. However, each TO should direct personnel to record such targets and reset the targets within a reasonable period of time after every 200 kV and above Automatic Outage. We believe this is a reasonable expectation.

As explained below, the above Fault Type data will enable the following understanding of actual system performance versus present perceptions regarding typical Fault Types:

- What percent of transmission line *Single Mode Outages* are reported with a Fault Type that indicates a multi-phase fault to ground? (Type 4, a fault between two or more phases to ground) This is useful to understand when looking at planning and operating stability studies and credible contingencies. It also provides useful information during review of the TPL (Transmission Planning) standards (Table 1, Category B events). If both phase target(s) *and* ground target(s) are reported, then it will be assumed that most of these reported outages are multi-phase to ground faults.

- What percent of *Common Mode and Dependant Mode Outages* are reported with just a single phase to ground fault? (Type 3, a single ground relay target and no phase targets) This percentage provides useful information during review of the TPL planning standards (Table 1, Category C events) and planning stability analysis for FAC standards addressing operations.

- What percent of *Common Mode and Dependant Mode Outages* are reported with a Fault Type that indicates a multi-phase fault to ground? (Type 4, a fault between two or more phases to ground) This is useful to understand when looking at planning stability studies and credible Table 1 Category D events. If both phase target(s) *and* ground target(s) are reported, then it will be assumed that most of these reported outages are multi-phase to ground faults; however, some of these faults may be three-phase faults to ground (but this determination is not definitive only based on targets).

- What percent of outages are reported with faults that are only between two phases? (Type 2)

d. TADS does not consider the relative importance of circuits. (AEP, National Grid) TADS does not account for the deferred restoration of non-critical circuits, different operating and maintenance practice, and major events such as storms. (Georgia Transmission, TVA)

We would not know what criteria to use to define the level of importance of a circuit in a consistent manner for all Transmission Owners. System operators dispatch the system so that loss of a single circuit can be accommodated. The importance of a circuit relative to others circuits is situation dependent, and the loss of any circuit will reduce the capability of the transmission system and potentially increase operating constraints. The critical nature of a circuit can also change over time. What may be non-critical today may be very critical in two years.

While the deferred restoration of a non-critical circuit may be a practice of certain TOs, in our opinion it does not warrant any special outage accounting. Other equipment, such as a generator, is counted as unavailable until it is capable of being returned to service, regardless of whether it was needed or not during its outage. Like Transmission Owners, generator owners have different operating practices, but again, those do not affect outage accounting. With respect to major events such as storms, we have a Cause Code (Weather, excluding lightning) that will permit us to isolate weather-related outages.

e. **Change the definition of Automatic Outage to "Any loss of the ability to supply partial or continuous power flow through a system Element by valid or invalid action of protective systems and/or control systems." Include single pole operations and events such as, dropping a pole in a breaker via a failed lift rod, switches burning clear on one pole and breakers mechanically falling off the latch. (SERC VMS, TVA)**

   We agree. The opening of a single circuit breaker due to the events described above will open the entire AC Circuit without "being triggered by an automatic protection device," a phrase in the present definition We will modify the definition so that the situation described above is included as an Automatic Outage.

f. **Change the definition of Momentary Outage from "less than 60 seconds" to "60 seconds or less" to align with other reliability indices. (AEP, National Grid, TVA) Change the definition of Momentary Outage to 2 minutes or less to align with some breaker reclosing schemes that are set for 60 seconds and may be recorded to be greater than 60 seconds (KCPL)** ***(In both cases, the Sustained Outage definition would also needed to be modified.)***

   We researched this definition before adopting it. It matches the definition used by WECC, CEA, EIA, ECAR, although it does not match EPRI's definition which uses "60 seconds or less." We gave weight to what the industry now collects.

g. **Do not require data to be input in Greenwich Mean Time (UTC) as it will lead to errors. Use local time and have NERC data software make the change based upon each TO's input time zone. (Ameren, KCPL, National Grid)**

   Our concern is the following scenario: We require data to be reported by each TO. If a single TO operates different control centers in different time zones, we would have to treat the TO as several TOs in order to accommodate time data being reported from different time zones. Therefore, the conversion is more efficiently done at the TO level. Another fact is UTC is required in Standard PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting in requirement R.1.1:

   > "Internal Clocks in DME [disturbance monitoring equipment] devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)."

We will be removing references to Greenwich Mean Time from our Report and replacing it with Universal Coordinated Time which reflects a more up-to date terminology.

h. Input Outage Start and End Times and calculate Outage Duration. (KCPL). Input Outage End Times and re-format Outage Duration hour and minute inputs into a single column (Ameren).

Because we rounded the Outage Start-Time to the nearest minute, we felt that a calculation of duration by use of an "Outage End Time" that was similarly rounded could produce erroneous results. The reason is that a simple difference of rounded inputs could produce an outage time of greater than one minute, the demarcation between a Sustained and Momentary Outage, when it is actually less than a minute. That is why we state that Momentary Outages specify a "zero" time duration. In addition, specifying outage duration will avoid data error entries caused by one of the outage end time being input incorrectly.[9] Finally, we ask TOs to input an Outage Duration of "9999" for an outage that starts in one year and is not concluded at the end of a reporting year.

We will re-format the Outage Duration inputs on Forms 4.1-4.4 into a single column.

i. Only report tie lines with joint owners and not tie lines with a single owner (CenterPoint). Who will determine reporting responsibility for tie lines and jointly-owned circuits? (ITC).

We believe that reporting of all tie lines, whether jointly owned or not, will allow the RE and NERC to ensure that they have been accounted for and that only one TO will be reporting data. We will clarify that even single owners of a tie line must report them. For tie lines with multiple owners and jointly-owned circuits, we will leave it to the owners to determine who will assume reporting responsibility. We will make that clear in the Manual.

j. Outage Initiation Codes, which capture where an outage initiated, could be replaced by expanding the Failed Equipment code. (ITC)

We respectively disagree. The suggestion assumes all outages are caused by Failed Equipment.

k. If a Transformer is outaged, is the Outage Initiation Code Element-Initiated, Substation-Initiated, or both? (TVA)

It depends. If the Transformer is an Element (i.e., low-side ≥ 200 kV), and the outage is 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 inside a Substation. However, if the Transformer outage was not due to the Transformer itself but due, for example, to a failed circuit breaker, the outage will be Substation-Initiated. We will clarify this in the revised Manual.

l. On Initiating and Sustained Outage Cause Codes, ITC only identifies root causes and therefore Sustained Outage Cause Codes. The WECC companies only record Initiating Outage Cause Codes, and they requested a one-year delay in requiring Sustained Outage Cause Codes. Progress Energy tracks a primary

[9] Experience has shown that the outage end time is the one most subject to errors.

and secondary cause codes, but they do not necessarily always track the TADS Initiating/Sustained Outage Cause Codes.

We have reconsidered and will compromise given WECC's size. In 2008, TOs are to report whichever Cause Code they have available for Sustained Outages, but if both are available, we want both to be reported. We will add an "Unavailable" Cause Code for 2008 for this purpose of identifying which Sustained Cause Code is unavailable for reporting. However, beginning in 2009, we will expect all TOs to supply both Initiating and Sustained Outage Codes.

m. Many suggestions were received regarding Cause Code changes.

i. If equipment fails and causes an outage, TADS should have the capability to determine *what* type of equipment failed. (AEP, National Grid, IESO, ITC, KCPL)

We agree and believe the best way to accommodate this is to expand the Failed Equipment Cause Code into more specific failed equipment categories.

We will eliminate the "Failed Equipment" and "Relay and/or Control Misoperation" codes and replace them with these codes:

- Failed AC Substation Equipment
- Failed AC/DC Terminal Equipment
- Failed Protection System Equipment
- Failed AC Circuit Equipment
- Failed DC Circuit Equipment

We will also make it clear that Failed Protection System Equipment will not include incorrect relay or control setting and that these should be categorized as "Human Error." We will also modify other the definitions of AC Substation and AC/DC Terminal to be consistent with these new Cause Codes, and we will add the definition of "Protection Equipment" from the NERC Glossary of Terms. Finally, we will separate the Outage Initiation Code for "Substation/Terminal Initiated Outage," which is now combined for AC and DC applications, into two separate codes.

ii. Modify the Relay and/or Control Misoperation code and Human Error codes so that an incorrect relay setting is Human Error rather than included as a Relay and/or Control Misoperation. (Northeast Utilities, IESO)

We will make this change as described in Section 5.m.i above.

iii. Make two Relay and/or Control Misoperation codes- one for a failure of the device itself and another for a non-device failure. This would distinguish between equipment failures versus a misoperation due to other causes. (TVA)

TVA's suggested "non-device failure" category has Human Error causes ("… incorrect settings, improper calibration, jarring the device, or improper installation or maintenance of the device"). Therefore we believe these are better included in Human Error as described in Section 5.m.i above.

iv. **Clarify that Human Error includes accidental of unintentional acts of company employees. (Great Lakes Power)**

We believe this is already covered by the "incorrect action" language in the definition of Human Error.

v. **TVA suggested that Human Error should be expanded to include "design and construction errors."**

For now, we believe that design and construction errors should be classified under the appropriate "failed equipment" category as describes in Section 5.m.i above. The failed equipment categories could be expanded in the future to account for design and construction errors as a sub-category.

vi. **Add a code for outages that are caused by another interconnected utility. (ITC, KCPL)**

We believe that recording the appropriate Cause Code as opposed to who caused the outage is more important. As described in Report Section 5.2.2, we will know whether TO outages are "linked." If one TO's outage causes a second TO's outage, the second TO's outage should be listed as a Dependent Outage with its own Cause Code.

vii. **Clarify the Vegetation Cause Code so that it excludes human errors for contractors inadvertently felling trees into lines, thereby making it consistent the with similar exclusions in FAC-003-1. (IESO, SERC VMS, TVA)**

We agree. We will make the "Vegetation" Cause Code definition consistent with the vegetation management standard exceptions in FAC-003-1.

viii. **For "Weather, excluding lightning," clarify that it includes "flying debris caused by wind." (TVA)**

We agree and will modify the definition.

ix. **Add another code (Foreign Interference) to include outages caused by non-company personnel, the public, or animals. (Great Lakes Power)**

We have a Foreign Interference code that covers these events and excludes outages caused by "a utility employee or contractor." Therefore, we believe our Foreign Interference definition covers the outages posed by Great Lakes Power.

n. **For each Sustained Outage, add a code that would be answer (yes/no) whether repairs or intervention is required before returning the Element to service. This is a re-statement of TVA's suggested "Intervention Required Outage." (TVA)**

We do not feel that a separate outage attribute is warranted at this time as a separate outage field on Form 4.1-4.4. For outages *not* requiring maintenance before being returned to service, if the cause cannot be determined, we suggest that the "Unknown" Cause Code be used. If repairs or intervention are required (TVA cites "repairs to lines or equipment, removal of foreign interference, or removal of vegetation") then the appropriate Cause Code should be used.

o. **WECC asked how an Event Type No 30 or 40 could be identified if the name of the shared circuit is never referenced; i.e., two owners have different circuits on common structures.**

For AC Circuits only, we will add a flag that identifies whether the outage was on a circuit that is on common structures with another TO's circuit. We will also add procedures in the revised Manual for this situation. (All DC Circuits are on common structures and the circuits are not separately owned by different Transmission Owners. Therefore, this situation does not apply to them.)

p. **In Report Section 4, it was unclear as to whether all outages would be included in the outages reported in Section 4.b.1 or whether the Event Type No. 30 and 40 outages described in Section 4.b.2 would excluded from outages reported in Section 4.b.1. (IESO)**

All outages will be used for the metrics described in Section 4.b.1. We will clarify this in the revised Report.

6. Comments Related to the Questions 3

Question 3 asked "*Are the metrics appropriate? See Section 4.b and Appendix 4 of the Report. If "no," please explain*." Most commenters agreed that the proposed metrics were a good starting point. In other cases, commenters provided no response. However, we had several specific comments.

a. **Do not include a metric calculating outage frequency per 100 circuit miles because it is misleading for various reasons. (Georgia Transmission, Pepco Holding, Exelon). ATC suggested that this metric be calculated by first removing outages that are Substation/Terminal-Initiated.**

We will calculate "per 100 circuit mile" metrics two ways: 1) *including* all outages; and 2) *excluding* outages that are unrelated to circuit mileage (e.g. Substation-Initiated Outages). The latter will result in a metric that is directly related to the geographic exposure of the AC (or DC) Circuit itself.

b. **For trending purposes, several years of data will be required for the trends to be meaningful. (National Grid, IESO)**

We agree that trending cannot be useful until several years of data are collected. We will state that in our revised Report.

c. **Progress Energy asked "Are there plans to look at system level metrics? If so, what would these metrics be used for?"**

As explained in Report Section 2.4.5, we cannot develop system level metrics since TADS is only addressing part of the transmission system. We have no present plans to expand TADS to lower voltages at this time. However, NERC is actively researching possible system level metrics that may utilize some of the TADS results to measure whether system level reliability is improving.

d. **Adopt the delivery point metrics in *EPRI Transmission Grid Reliability Performance Metrics, Final Report*. (AEP, KCPL).**

Our concerns regarding the EPRI delivery point metrics, and why we did not adopt them, are explained in the Report in Section 2.4.5.

e. **Several commenters expressed concern that the Mean Time to Repair (MTTR) metric might be exaggerated by long-term outages due to damaged equipment (i.e. downed transmission lines due to tornados, auto-transformer failures, etc.). (KCPL). In addition, it would be overstated if non-critical repairs are deferred to work on other repairs (KCPL), or if the owner practices deferred restoration of non-critical lines (Georgia Transmission). ITC expressed related concerns.**

   We recognize that MTTR is an average, and it is greatly impacted by the cause of the outage. That is one reason we are also computing Median Time to Repair. In addition, we can calculate both MTTR and MdTTR by Cause Code, which will provide more information than a single value based upon all Cause Codes. We will also be calculating MTTR standard deviations.

f. **ITC stated the following:**

   > **"The metrics are appropriate if each Transmission system reporting outages can be put on a "like" basis. It's difficult to compare systems that experience completely different weather patterns based on their geographic location, e.g. hurricanes in the South, ice storms in the Midwest. There was no mention of running data filters to "clean-up" the data and make it more consistent. Some of the metrics TADS is calculating will be skewed if raw outage data is being used."**

   As stated in Report Section 2.6, we do not intend to compare the metrics of TOs or regions. A particular TO's metrics will certainly be different from the regions metrics, which represents the average performance of all TOs in the region. We believe that a TO will want to interpret why their metrics differ from the region's metrics, and as stated in Section 6.e above, we intend to calculate many metrics by Cause Codes to facilitate this interpretation.

g. **National Grid asks "Is it important to count automatic operations or the number of operations that should have occurred automatically (perhaps both are required)?"**

   All system protection initiated automatic outages are the result of either desired operations or misoperations. The number of outages that are a result of misoperations cannot be determined by TADS because some of these may be classified as Human Error as described in Section 5.m.ii in this document. All misoperations, however, are analyzed in standard PRC-004, Analysis and Mitigation of Transmission and Generation Protection System Misoperations.

h. **Hydro One states "A more appropriate approach would be to determine the metrics that would provide NERC with reliability knowledge they require rather than establish metrics on the basis of data that seem to be widely and presently available within the industry."**

   We debated this issue and chose to initially develop metrics based upon data that is commonly available. Using metrics based upon available data will provide a starting point for better metrics (and better data) in the future.

i. **Oncor asked whether "an in-service element with planned outages for one-fourth of the year is statistically different than a new element placed into service for three-fourths of a year.**

We will not include planned outages in Phase I. However, if we collected planned outage data, the metrics, after modification to include planned outage hours, would recognize the equivalence of the situation posed by Oncor.

j. WECC questions whether it is necessary to prorate Elements for mid-year additions or retirements, especially as multi-year data is available in future years.

We note that prorating an Element to recognize mid-year changes, whether additions or retirements, is a refinement. However, it uses readily available information and therefore does not appear burdensome. In addition, for Transmission Owners with a small number of Elements in a Voltage Class, prorating will "smooth" their individual year-to-year metrics. We will evaluate this next year to determine whether the refinement continues to be beneficial.

7. Comments Related to the Questions 4

Question 4 asked "*Is the data reporting process reasonable? See Section 5.2 of the Report. If "no," please explain."* Most felt that the data reporting process was reasonable, but several expressed concerns about the roles of the Regional Entities.

a. Several entities questioned the ability of Regional Entities to add additional data to TADS.

- **Hydro One asked that we remove the statement in the Report that "An RE may request additional data from the TOs in their footprint."[10] In support of this request, Hydro One writes "NERC should not be making any statements on the requirements of other entities, and be limited to NERC's requirements only."**
- **Duke Energy states:**

  "It appears that Regional Entities will have latitude to increase the scope of the data request, which would eliminate the benefits of standardization. There should only be one standard data request, and it is unclear that having the Regional Entities in the data collection loop will be efficient."

Additional RE data requests by may be either mandatory or optional, depending upon the REs agreements with its members, but in either case, the statement challenged by Hydro One is true. NERC cannot limit or extend or limit the authority of an RE by such a statement. If REs can request additional data, we believe it is more efficient for them to bundle it with the TADS request rather than issue a separate data request.

b. Progress Energy states that providing an output data file would be preferred over the suggested data forms.

The data submittal process is under development, but we agree with Progress Energy's statement and will consider it as that process is developed.

c. IESO said that NERC should not be re-checking data that REs have reviewed.

[10] See Report Section 1, paragraph e.

Our intension is not to duplicate RE data checking. We expect NERC software for accepting and managing data will have data error checking at the data entry level which should reduce errors and increase consistency. We will clarify this in our revised Report.

d. Ameren asked whether individual Transmission Owner confidential reports will have more detailed metrics such as outage statistics related to specific Elements.

We have not developed the NERC and regional report formats. But at a minimum, TO reports will contain the same metrics that are computed at the regional level.

8. Comments Related to the Questions 5

Question 5 asks "*Is the implementation schedule for Phase I TADS for 2008 reasonable? See Section 5.3.1 of the Report. If "no," please explain."* The majority of Transmission Owners (20 out of 29) stated that they felt that the implementation schedule was reasonable, but they generally recognized that 2008 would be a challenge as a start-up year. Others offered no comment or had specific concerns.

a. The Energy Information Administration stated that the implementation schedule…

> **"…does not meet the needs of the Federal government for timely delivery of transmission outage data. The reporting of the data on the Form EIA-411 is still needed. We have stated that improvements in the definitions can be made to the form to assist NERC and its members to more easily comply with the survey requirements. The EIA has also stated that when the TADS development process comes closer to a final business model, that the EIA and DOE will review the process. Our hope is for common data elements, so that one reporting format can be used to keep the reporting burden on industry to a minimum."**

Our timeline could not start TADS Phase I data collection prior to 2008. We are encouraged by EIA's openness to work with NERC on developing a single process. We look forward to reviewing TADS with EIA and DOE.

b. Several entities asked commented about our schedule.

- **Georgia Transmission, Manitoba Hydro, Progress Energy, and Southern Co. expressed concern about short time frame for programming changes needed after TADS is finalized.**
- **SERC VMS stated "An undertaking of this magnitude will take significantly more time than proposed. The VMS suggests that 24-36 months be added to the proposed reporting deadlines."**
- **TVA stated that the implementation schedule is not reasonable:**

  > **"As indicated above the impacts to implement Phase I of TADS will be significant. Revisions to TVA's interruption data base, governing procedures and data submittal forms as well as the development and delivery of training for personnel make the May 30, 2008 submittal date for first quarter data extremely difficult. Final approval of TADS is**

currently not set until October 22, 2007, which provides little more than 2 months to implement TADS changes for 2008 data.

A more realistic date to overcome many of the challenges associated with this process and beta test on real world data is calendar year 2009. This will also allow the metrics to be evaluated more fully to determine those elements that provide the most value and thus set the stage for Phase II to begin in 2010.

A second possibility would be for utilities to report circuit outages by TADS cause codes and duration only for the first year. Other reportable items could be phased in over two more years."

We understand the timing concerns. As we stated in Report Section 5.3.1, manual input may be required in 2008.

c. **WECC requested that we defer the reporting of an Event Type Number for one year.**

Although we started with approximately 20 Event Type Numbers, we kept the Event Type Number convention fairly simple with five codes for start-up. Therefore, we do not believe providing this data should be difficult and should not be delayed. See Report Section 2.4.6 for a more complete explanation of Event Type Number.

d. **Training is needed on an accelerated basis. (JEA) Prepare a Web template to facilitate data capture and offer training in its use (TVA).**

We agree, and our revised Report will address both training and data entry.

9. Comments Related to the Questions 6

Question 6 asks "*Are there ambiguities in the Manual that need clarification? If "yes," please explain."* These questions are addressed below.

a. **WECC asks for clarification on how to compute the weighted Elements and the weighted Circuit Miles.**

The Manual has sample calculations in Appendix 7

b. **Ameren describes two three-terminal circuit examples, one with a 138 kV transformer on one terminal and second with a 230 kV transformer on one terminal. Ameren suggested that for a transformer outage, the outage condition of the circuit is different for different voltage transformers. Oncor also commented on three-terminal circuit examples in Appendix 8 of the Manual.**

The Ameren examples are described in the definition of In-Service State. However, the outage condition of the circuit does not depend upon the voltage of the transformer as suggested by Ameren.

To answer Oncor, the three terminal line examples (Event ID Codes: 0001, 0002 and 0005) demonstrate an exception to outage reporting when an Element has a shared switching device (i.e. circuit breaker). This exception is explained further in the definition of "In-Service State" in Appendix 2 of the Report. We acknowledge that this may be different then some entities currently record outage information, but we felt that exception was reasonable.

c. **Ameren asks several questions about Form 4.2, but after following up with them, they intended their questions to apply to Form 4.1:**

   i. **What is the purpose of "Row No." on forms?**

      It provides a reference point for discussing data inputs.

   ii. **Revise the Event ID Code input format by making the year a separate column.**

      We respectively disagree. As explained in the definition of Event ID Code, the "year" input on the code allows us to determine whether an Event ID Code in a particular year is from a prior year. As designed, it allows a TO to re-use the Event ID Code labeling format that precedes the year input. A separate column may result in unintentional errors being introduced by making it tempting to copy the year down.

   iii. **If a circuit has a Transformer that has a secondary voltage ≥ 200 kV and which is different that the primary voltage of the circuit, how is the circuit voltage designated?**

      The voltage of the AC Circuit is not related to the secondary voltage of the Transformer. The AC Circuit voltage is its phase-to-phase voltage.

   iv. **What if a circuit has more than two terminals?**

      The form allows for up to three terminals (columns C, D, and E).

   v. **If TADS wants AC Substation names to be those in power flow library, it should be clear.**

      We will remove the suggestion that AC Substation names be those on the power flow library.

d. **ITC suggests that circuit ID could be used to identify an outaged circuit rather than terminal names.**

   We would need a complete Element inventory to use a circuit ID, which we felt be an additional start-up burden. That is why we requested Substation names.

e. **ITC asked whether the weighted average percent of the year that are Elements added or retired is input by the TO or calculated by TADS.**

   It is input. TADS would need information on each added or removed Element to calculate this value, and this feature was not designed into TADS.

f. **ITC asked whether the number of Elements with zero outages each year is calculated by TADS or input.**

   It is input. See Table 3.4 in the Manual for a description of the required input.

g. **CenterPoint asks that Web site addresses for the disturbance report filings (OE-417 and EOP-004) be added to the Manual.**

   We agree and will provide the Web site references in the revised Manual.

h. CenterPoint suggested improved instructions regarding Greenwich Mean Time and Multi-Circuit Structure Miles.

We agree and will clarify the instructions in the revised Manual.

i. Explain the process that will be used to answer questions that arise (ATC).

We will improve this section of the revised Manual.

j. TVA noted several typographical errors.

We appreciate TVA pointing these out. They will be corrected.

k. Several comments were received about potential errors in Appendix 7 (JEA, TVA)

We will correct these errors.

l. JEA asked for an improved explanation of why two of the three outages on page 59 of the Manual are due to relay misoperation rather than breaker failure.

We agree and will add a better explanation.

Appendix A

The letter requesting comments on TADS follows.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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

June 28, 2007

TO: INDUSTRY STAKEHOLDERS

Ladies and Gentlemen:

Request for Public Comment on TADS Report and Manual

The North American Electric Reliability Corporation (NERC) requests public comment by August 15, 2007 on its proposed Transmission Availability Data System (TADS). Comments must be submitted in a Word document to John Seelke (john.seelke@nerc.net).

TADS is described in the Transmission Availability Data System Final Report ("Report") that was approved by NERC's Planning Committee on June 7, 2007, as well as in the Data Reporting Instruction Manual ("Manual"), dated June 29, 2007. These documents may be downloaded at http://www.nerc.com/~filez/tadstf.html, and comments are requested on both documents.

TADS was developed over an eight-month period by a Planning Committee task force. It is a data request, not a standard. Therefore, we have provided summary information in Section A below about TADS in accordance with NERC's proposed rule on requests for data or information. The proposed data rule was posted on May 21, 2007, and may be downloaded at http://www.nerc.com/~filez/rules_of_procedure.html.

A. TADS Summary Information

The italicized language is information that must accompany a data request.

1. *A description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information will foster NERC's ability to meet its obligations.*

   Our response is provided in subparts. Capitalized terms are definitions that are contained in Appendix 1 of the Report.

   a. *A description of the data or information requested.*

      Phase I TADS will be collecting Automatic Outage data for the transmission facilities listed below, beginning with data for the 2008 calendar year.

      - 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

      The specific data that is being requested is described in Section 3 of the TADS Report as well as in the Manual.

      A Phase II TADS for planned outages and unscheduled manual outages is under development, and that effort is not part of this data request.

b. *How the data or information will be used.*

NERC will use the information to develop transmission metrics that analyze outage frequency, duration, causes, and many other factors related to transmission outages. A description of these metrics is in Section 4 of the Report.

A public report showing common metrics for each NERC region will be prepared annually, and each Transmission Owner reporting TADS data will be provided a confidential copy of the same metrics for its facilities. This is discussed in Section 5.2.3 of the Report.

c. *How the availability of the data or information will foster NERC's ability to meet its obligations.*

We believe the greatest use of the data will be for outage-cause analysis and outage Event analysis. Event analysis will aid in the determination of credible contingencies and will result in better understanding, and this understanding should be used to improve planning and operations. Ultimately, these improvements should result in improved transmission system performance, which is consistent with NERC's obligations. Section 2.6 of the Report further describes the intended uses and limitations of the data.

2. *A description of how the data or information will be collected and validated.*

This information describes a coordinated effort between NERC and the Regional Entities. Data will be validated initially by the Regional Entities and finally by NERC. The data collection and validation process is described in Section 5.2 of the Report.

3. *A description of the entities that will be required to provide the data or information ("reporting entities").*

Transmission Owners registered with NERC will be required to report TADS data, ss described in Section 5.1 of the Report.

4. *The schedule or due date for the data or information.*

For 2008, there are two data submission dates: May 30, 2008 (for data collected through March 31, 2008) and March 1, 2009 (for the balance of 2008 data). Since the start-up year will be 2008, we developed a timetable that would attempt to catch any fundamental design or implementation issues early rather than wait until year-end.

For 2009, data will be due on March 1, 2010. We expect this pattern to hold for subsequent years. A data collection timetable of 2008 and 2009 is provided in Section 5.3 of the Report.

5. *A description of any restrictions on disseminating the data or information (e.g., "confidential," "critical energy infrastructure information," "aggregating" or "identity masking").*

All Transmission Owner confidential information will be protected pursuant to NERC's confidential information policies in Section 1500 of its Rules of Procedures. In addition, TADS public reports will not inadvertently release confidential information by the display of regional or NERC information from which a Transmission Owner's confidential information could be ascertained. For example, if the Transmission Owner in a region is the only owner of assets in a particular Voltage Class, the metrics on that data would not be released if the Transmission Owner's name and its confidential information could be identified. Section 2.4.7 of the Report addresses data confidentiality, while Section 5.4 addresses data access policies.

However, we do not believe that all the information to be submitted will be confidential information. Section 1.3 of the Manual provides our assessment of the confidentiality of data, broken down by the data requested on each data form

6. *An estimate of the relative burden imposed on the reporting entities to accommodate the data or information request.*

   Many Transmission Owners already collect some type of transmission outage data, and these Transmission Owners will naturally be concerned with their ability to extract TADS data from existing data they now collect. Given the short start-up time associated with a 2008 implementation date, it may not be practical for Transmission Owners to modify their existing transmission outage data collection systems to extract TADS data. Therefore, we fully expect that supplying 2008 data may require a manual collection and extraction process. Given that we are limiting our request to facilities ≥200 kV, we do not expect the burden of collection to be excessive. Using the Energy Information Administration's Form 411 Schedule 7 submittals for 2006 as a benchmark, we know that the number of Sustained Outages will not be large. For example, ERCOT reported 86 Sustained Outages for 2006 while Southwest Power Pool reported 101 outages.

B. Comment Questions

While commenters are not restricted in the format of their comments, we would appreciate your answers to the following questions:

1. *If you are a Transmission Owner, do you currently collect transmission outage data similar to TADS? If "yes," please explain.*
2. *Is the data being requested reasonable and obtainable? See Section 3 of the Report. If "no," please explain.*
3. *Are the metrics appropriate? See Section 4.b and Appendix 4 of the Report. If "no," please explain.*
4. *Is the data reporting process reasonable? See Section 5.2 of the Report. If "no," please explain.*
5. *Is the implementation schedule for Phase I TADS for 2008 reasonable? See Section 5.3.1 of the Report. If "no," please explain.*
6. *Are there ambiguities in the Manual that need clarification? If "yes," please explain.*

Comments are due August 15, 2007 and must be submitted in a Word document to John Seelke (john.seelke@nerc.net).

Sincerely,

Appendix 6 TADSTF Members

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