

**Transmission Availability Data System  
Final Report**

**Prepared by:**

**Transmission Availability Data System Task Force**

**For:**

**NERC Planning Committee**

**June 7, 2007**

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## Table of Contents

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<b>1. Executive Summary .....</b>	<b>1</b>
<b>2. The Task Force’s Work.....</b>	<b>5</b>
2.1. Scope.....	5
2.2. Industry Practices Reviewed.....	5
2.3. EIA Data Collection Efforts.....	6
2.4. Fundamental Phase I TADS Structure Decisions .....	8
2.4.1. TADS Elements .....	9
2.4.2. Voltage Classes.....	9
2.4.3. Inventory Data .....	9
2.4.4. Outage Types .....	9
2.4.5. Impact Measures .....	10
2.4.6. Event Type Number .....	11
2.4.7. Confidentiality .....	11
2.5. NERC’s Authority to Require TADS Data.....	12
2.6. Intended Uses and Limitations of Data and Metrics.....	12
<b>3. Required Phase I Element Inventory and Outage Data.....</b>	<b>14</b>
3.1. General Data .....	14
3.2. Element Inventory Data .....	14
3.2.1. For All Elements.....	14
3.2.2. Additional Data for AC and DC Circuits.....	14
3.3. Element Outage Data .....	14
3.4. Event ID Code Data .....	16
<b>4. Phase I Metrics and Data Analysis.....</b>	<b>17</b>
<b>5. Data Collection, Analysis and Reporting Process.....</b>	<b>18</b>
5.1. Required Reporting Entities.....	18

5.2.	Overall Process .....	18
5.2.1.	Data Request Process .....	18
5.2.2.	Data Submittal and Review .....	18
5.2.3.	Analysis & Reporting .....	18
5.2.4.	Role of the Regional Entities .....	20
5.3.	Timetable .....	20
5.3.1.	2008 Reporting Year.....	20
5.3.2.	2009 Reporting Year.....	21
5.4.	Data Access Policies .....	21
<b>6.</b>	<b>Future Role of the TADSTF.....</b>	<b>22</b>
<b>7.</b>	<b>Next Steps .....</b>	<b>23</b>
Appendix 1	Letter Announcing the TADSTF .....	1-1
Appendix 2	TADS Definitions .....	2-1
Appendix 3	Planned Outage Data Collection Analysis.....	3-1
Appendix 4	Metric Formulas.....	4-1
Appendix 5	TADSTF Members .....	5-1

## 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 so for the overriding purpose of providing Transmission Owners (TOs) and NERC with the information to support decisions with respect to improving reliability and performance.

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.
- 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:<sup>1</sup>

- a. We recommend collecting outage data on four specific transmission Elements which operate at voltages  $\geq 200$  kV:
  - AC Circuits  $\geq 200$  kV (Overhead and Underground Circuits). Radial circuits are included.
  - Transformers with  $\geq 200$  kV low-side voltage
  - AC/DC Back-to-Back Converters with  $\geq 200$  kV AC voltage, both sides
  - DC Circuits with  $\geq \pm 200$  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

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<sup>1</sup> Capitalized terms are definitions that may be found in Appendix 2.

of unscheduled outages, and it is one which was not subject to interpretation difficulties.

- With respect to other outages, we excluded the requirement to collect planned outage data, a step that was approved by the Planning Committee at its March 21-22, 2007, meeting.
- d. Subject to approval by NERC's Board of Trustees (Board or BOT) at its October 22, 2007, meeting, Phase I TADS reporting will become a mandatory data submittal requirement on all Transmission Owners in NERC's registry for calendar year 2008.
- Prior to submitting TADS to the Board, this Final Report, as modified by the Planning Committee at its June 6-7, 2007, meeting, will be posted for a 45-day open comment period along with a Data Reporting Instructions document that is under development.
- e. 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.
- f. We have taken 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. 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.
- h. 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 Failure -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.

- i. 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.
- j. 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**

<b>Date</b>	<b>Item</b>
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 circuits 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.

- k. 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**

<b>Date</b>	<b>Item</b>
Mid-December, 2008	REs re-confirm that all tie-lines and jointly-owned circuits 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.

As shown in the tables below, the work of the TF will continue after the Planning Committee meeting on June 6-7, 2007.

**Phase I TADS Next Steps**

<b>Dates (2007)</b>	<b>Activity</b>
June 7-8	TF meeting on Phase I TADS Data Reporting Instructions
June 29	Post Final Report, as modified with the Planning Committees' recommendations, and Phase I TADS Data Reporting Instruction for comments (45 days)
July 2	Test Phase I TADS using July 1- Dec 31, 2006 data with TOs represented on the TADSTF (Beta test)
August 1	Complete Beta test and start cataloging suggested Phase I TADS Data Reporting Instructions changes
August 15	Receive comments from June 29 posting
August 27-30	TF meeting to (i) complete modifications to Phase I TADS from the Beta test and comments received from the June 29 posting, and (ii) begin initial Phase II discussions
September 12-13	Planning Committee meeting - provide the PC an update of TADSTF activities
Late September	Submit updated Final Report & Data Reporting Instructions, (including comments received and our response to them) to the Board of Trustees for approval
October 22	Board of Trustees decides on whether to give Phase I TADS its approval for mandatory 2008 reporting

**Phase II TADS Next Steps**

<b>Dates (2007)</b>	<b>Activity</b>
August 27-30	TF meeting to (i) complete modifications to Phase I TADS from the Beta test and comments received from the June 29 posting, and (ii) begin initial Phase II discussions
<b>Dates (2008)</b>	<b>Activity</b>
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 updated TADS Data Reporting Instruction for comments (45 days)
Early July	Submit updated Phase II Final Report & Data Reporting Instructions, (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 give 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.<sup>2</sup> 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 these 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.<sup>3</sup> Four meetings and numerous conference calls were convened. An Interim Report dated March 7, 2007, was written for review by NERC's Planning Committee at its March 21-22, 2007 meeting. The Interim Report was approved, and the committee endorsed our decisions in structuring TADS.

### 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>
- 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>.

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<sup>2</sup> See Appendix 1.

<sup>3</sup> Members are listed Appendix 5.

- 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.

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.<sup>4</sup> 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.<sup>5</sup> EIA's decision will not be made until the fall of 2007, since the proposed forms will replace the current 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.

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<sup>4</sup> 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](http://www.eia.doe.gov/cneaf/electricity/page/fednotice/elect_2008.html).

<sup>5</sup> EIA personnel in attendance were Scott Sitzer, Robert Schnapp, Tom Leckey, and John Makens.

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 (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 policies 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 discussed 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, we suggest that NERC respond to EIA's request for comments as follows:

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 suggest 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 propose 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. (Better yet, Schedule 7 could be dropped entirely, with NERC providing EIA its public TADS report that could include the all the regional data for Schedule 7.) 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. All of the capitalized terms are definitions that are contained in Appendix 2.

#### **2.4.1. TADS Elements**

We recommend collecting data on four specific transmission Elements which operate at AC and DC voltages  $\geq 200$  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  $\geq 200$  kV (Overhead and Underground Circuits). Radial circuits are included.
2. Transformers with  $\geq 200$  kV low-side voltage
3. AC/DC Back-to-Back Converters with  $\geq 200$  kV AC voltage, both sides
4. DC Circuits with  $\geq \pm 200$  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 triggered by automatic protection devices, in the initial Phase I implementation of TADS. 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.

- Automatic Outages will be classified into two categories: Sustained and Momentary, where Momentary Outages have durations less than one minute.
- An Automatic Outage is triggered by automatic protection 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.

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 its reliability standard EOP-004-1 (Disturbance Reporting).<sup>6</sup> The OE-417, which is the Department of Energy's Electric Emergency Incident Report and that is a requirement for U.S. utilities<sup>7</sup>, can be used as a substitute for EOP-004-1.<sup>8</sup>

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 time.
20	B	Automatic Outage of a DC Circuit with normal clearing time.
30	C	Automatic Outage of two ADJACENT AC Circuits on the same structure with normal clearing time.
40	C	Automatic Outage of two ADJACENT DC Circuits on the same structure with normal clearing time.
50	NA	Other - please describe the event

### 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

<sup>6</sup> EOP-004-1 is available at: [http://www.nerc.com/~filez/standards/Reliability\\_Standards\\_Regulatory\\_Approved.html](http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html).

<sup>7</sup> The OE-417 is available at: <http://www.eia.doe.gov/cneaf/electricity/page/forms.html>.

<sup>8</sup> Although Canadian regulatory authorities have not yet approved this standard (or any of the other recently FERC-approved standards), their approvals are expected.

request for the release of confidential information.<sup>9</sup> 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. 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.

Although NERC's Rules of Procedure do not yet have a rule specifying the mechanics for authorizing data request, NERC will be filing a "data rule" for FERC approval to 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 May, 1, 2007, agenda for the Members Representative Committee.<sup>10</sup>

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

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

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<sup>9</sup> NERC's treatment of confidential information is described in Section 1500 of its Rules of Procedure. The latest proposed version of Section 1500 is in NERC's March 19, 2007, Compliance Filing at [http://www.nerc.com/pub/sys/all\\_updl/docs/ferc/20070319\\_compliance\\_filing.pdf](http://www.nerc.com/pub/sys/all_updl/docs/ferc/20070319_compliance_filing.pdf). See Attachment 2.

<sup>10</sup> The May 1 MRC agenda is at <http://www.nerc.com/~filez/mrcmin.html>. See Item No. 9.

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.

### 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 will be incorporated in a Phase I TADS Data Reporting Instructions document that is under development.

#### 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 circuits, the name of the TOs which own these circuits, 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.

#### 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 and DC Circuits that occupy a common structure with other AC or DC Circuits, 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.

#### 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 Element Inventory and Outage Data

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required. In addition, an optional TO Element Identifier, which permits the TO to enter an alphanumeric name of the Element (such as a circuit no.) for its own use, is provided.

- iv. For AC or DC Circuits, whether it is an Overhead or Underground Circuit.
- b. 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.
- c. The Fault Type. Several selections are available:
  - i. There was no target because no fault occurred
  - ii. The fault had a phase target
  - iii. The fault had a ground target
  - iv. The fault had both a phase and a ground target
  - v. The fault's target is unknown.
- d. An Outage Initiation Code. The Outage Initiation Codes describe *where* an Automatic Outage was initiated on the power system. Three Outage Initiation Codes are available:
  - i. Element-Initiated Outage
  - ii. Substation or Terminal-Initiated Outage
  - iii. Other Facility-Initiated Outage
- e. 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 Greenwich Mean Time [a.k.a., Coordinated Universal Time (UTC)], not local time. By recording in GMT, 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.
- f. 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.
- g. An outage Cause Code. Sustained Outages require two Cause Codes: (i) an Initiating Cause Code 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, a lightning strike on an AC Circuit (the Initiating Cause Code) that should have cleared normally became a Sustained Outage because of a relay misoperation (the Sustained Cause Code). Momentary Outages do not have a Sustained Cause Code.
- h. The Outage Mode. Several Outage Mode categories are provided
  - i. A Single Mode Outage is an Automatic Outage which occurred independent of any other outages.
  - ii. A Dependent Mode Initiating Outage is a Single Mode Outage that causes 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 (an OE-417 or EOP-004-01 disturbance report filing). As described in Section 2.4.5, the TO may select “yes,” “no,” or “unknown.”

## 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. We expect NERC to either acquire or have developed TADS analysis software for processing the metrics described below.<sup>11</sup>

- 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.
  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 Failure -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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<sup>11</sup> For 2008, NERC has budgeted funds for a full-time TADS manager, one-half of a technician, and \$150,000 for software costs.

## 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 with NERC. 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 registers with NERC for this purpose. However, the TO with the reporting obligation is ultimately responsible for ensuring the timely and accurate reporting of data.

### 5.2. 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.

#### 5.2.1. 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.

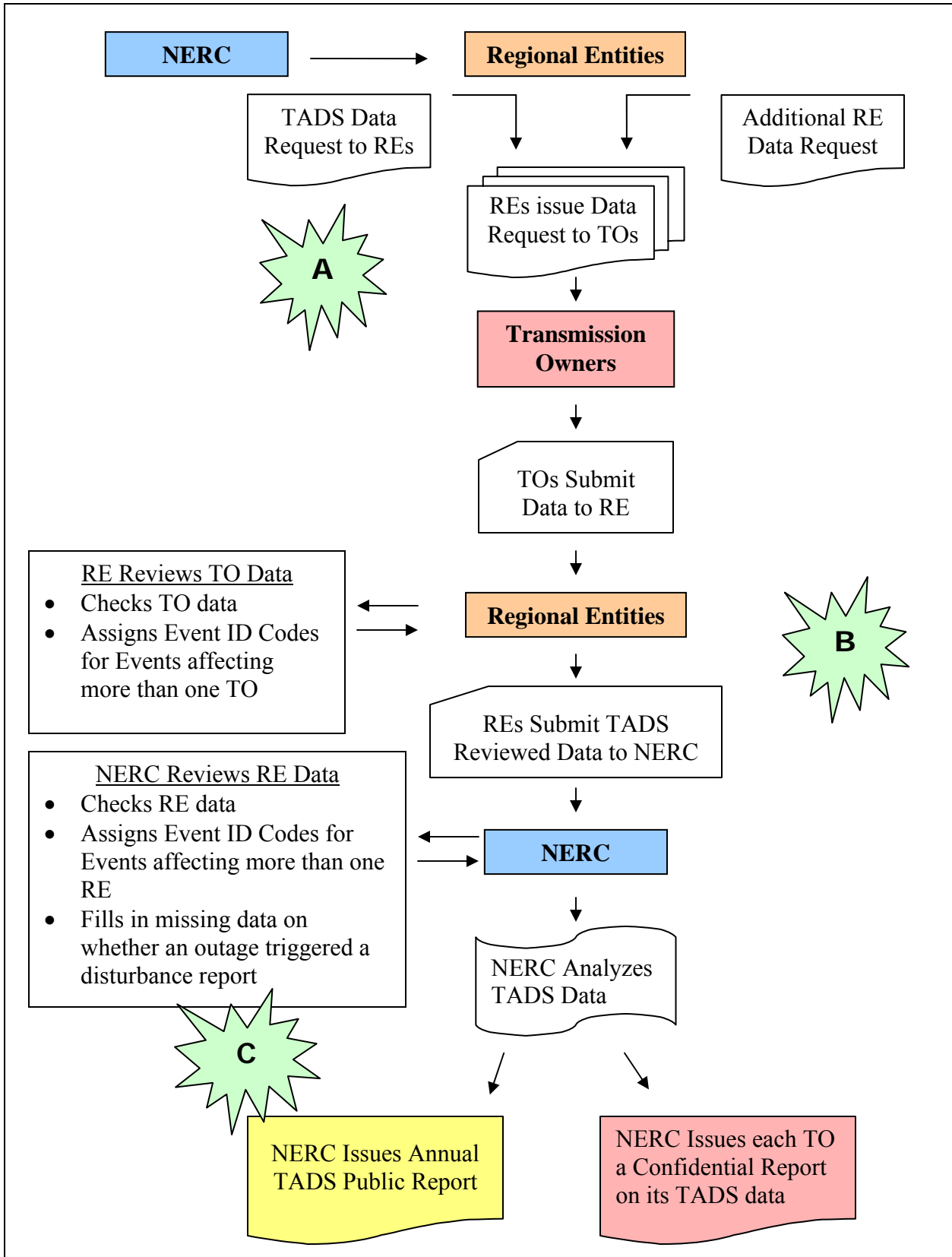
#### 5.2.2. Data Submittal and Review

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. 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. REs will then submit the TADS portion of the checked data to NERC. NERC in turn, will do a second high-level data check. It will also review RE Event ID Code data and assign a common Event ID Code to any Events that cross RE boundaries. In addition, NERC will research OE-417 or ERO-004-01 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.

#### 5.2.3. Analysis & 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.

Figure 5.0: TADS Process



### **5.2.4. 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:

- Participate in NERC’s training of TOs
- Request data from TOs
- Review tie-line and jointly-owned circuits to ensure that a single TO is responsible for 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
- Respond to questions from TOs, with NERC support.

### **5.3. Timetable**

#### **5.3.1. 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**

<b>Date</b>	<b>Item</b>
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 circuits 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.

### 5.3.2. 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 re-confirm that all tie-lines and jointly-owned circuits 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.

### 5.4. 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.

## 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 is on the next page.

- a. Data Reporting Instructions. We will produce Phase I TADS Data Reporting Instructions, a document which will be aimed at providing TOs with information and examples to assist them in implementation. We do not intend to seek Planning Committee approval for this document since it will only be focused on implementation details and not policy issues.
- b. Posting TADS for Comments. After completing the Data Reporting Instructions, we will post the Final Report, which will incorporate the recommendations of the Planning Committee, and the Phase I TADS Data Reporting Instructions for NERC-wide comments for a 45-day period, soliciting as many comments as possible.
- c. Beta test (Phase I). After posting TADS for comments, we will commence a test of the Data Reporting Instructions with the TOs represented on the TF, using personnel from their organizations who are new to TADS (Beta test). The objective is to improve the instructions before implementation. This effort will run in parallel with the comment period.
- d. Board of Trustees TADS Approval. By late September, we will submit a TADS package to the Board of Trustees for their October 22, 2007, meeting, seeking their approval to require mandatory TADS submittals for the calendar year 2008. Our final package will include any modifications we accepted pursuant to comments received, as well as our response to comments we did not accept.
- e. 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 will then add their specific data requests and submit a bundled request to TOs.)
- f. Development of Phase II TADS. This work is scheduled to commence in August 2007 and be concluded in 2008 for mandatory implementation for data collected in calendar year 2009.

**Phase I TADS Next Steps**

<b>Dates (2007)</b>	<b>Activity</b>
June 7-8	TF meeting on Phase I TADS Data Reporting Instructions
June 29	Post Final Report, as modified with the Planning Committees' recommendations, and Phase I TADS Data Reporting Instruction for comments (45 days)
July 2	Test Phase I TADS using July 1- Dec 31, 2006 data with TOs represented on the TADSTF (Beta test)
August 1	Complete Beta test and start cataloging suggested Phase I TADS Data Reporting Instructions changes
August 15	Receive comments from June 29 posting
August 27-30	TF meeting to (i) complete modifications to Phase I TADS from the Beta test and comments received from the June 29 posting, and (ii) begin initial Phase II discussions
September 12-13	Planning Committee meeting - provide the PC an update of TADSTF activities
Late September	Submit updated Final Report & Data Reporting Instructions, (including comments received and our response to them) to the Board of Trustees for approval
October 22	Board of Trustees decides on whether to give Phase I TADS its approval for mandatory 2008 reporting

**Phase II TADS Next Steps**

<b>Dates (2007)</b>	<b>Activity</b>
August 27-30	TF meeting to (i) complete modifications to Phase I TADS from the Beta test and comments received from the June 29 posting, and (ii) begin initial Phase II discussions
<b>Dates (2008)</b>	<b>Activity</b>
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 updated TADS Data Reporting Instruction for comments (45 days)
Early July	Submit updated Phase II Final Report & Data Reporting Instructions, (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 give Phase II TADS its approval for mandatory 2009 reporting

**Appendix 1 Letter Announcing the TADSTF**

The letter announcing the TADSTF follows.



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](mailto:gagnon.jean-marie@hydro.qc.ca)) and copy John Seelke of the NERC staff ([John.Seelke@nerc.net](mailto:John.Seelke@nerc.net)).

Sincerely,

Scott M. Helyer  
Chairman  
NERC Planning Committee

Attachment  
cc: Operating Committee

## Transmission Availability Data System (TADS) Task Force

Purpose(s)	<p>In order to quantify or measure system performance and reliability, the TADS Task Force will recommend:</p> <ol style="list-style-type: none"> <li>a. The <u>type</u> of transmission availability data that transmission owners will report to NERC;</li> <li>b. A single <u>process</u> for collecting such data that avoids duplication of effort;</li> <li>c. The transmission availability <u>statistics</u> that would be calculated from the reported availability data; and</li> <li>d. <u>Guidelines</u> for release of such data and statistics.</li> </ol>
Background	<p>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.</p> <p>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.</p>
Scope of Activities	<ol style="list-style-type: none"> <li>a. Catalog the type of transmission availability data currently being collected by NERC members as well as the uses of the data.</li> <li>b. Recommend a common data reporting framework or protocol.</li> <li>c. Develop common availability statistics that could be computed from the data.</li> <li>d. Recommend guidelines for the sharing and release of data.</li> </ol>
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**

**June 7, 2007**

## Table of Contents

A.	TADS Population Definitions.....	1
	1. Element .....	1
	2. AC Circuit .....	1
	3. Transformer.....	1
	4. AC Substation .....	1
	5. AC/DC Terminal.....	1
	6. AC/DC Back-to-Back Converter .....	1
	7. DC Circuit .....	1
	8. Overhead Circuit .....	1
	9. Underground Circuit .....	2
	10. Circuit Mile .....	2
	11. Multi-Circuit Structure Mile .....	2
	12. Voltage Class .....	2
B.	Outage Reporting Definitions.....	2
	1. Automatic Outage .....	2
	2. Momentary Outage: .....	2
	3. Sustained Outage: .....	2
	4. In-Service State .....	3
	5. Substation, Terminal, or Converter Name .....	3
	6. TO Element Identifier .....	3
	7. Outage Start Time .....	3
	8. Outage Duration.....	3
	9. Event .....	4
	10. Event Identification (ID) Code.....	4
	11. Event Type Number .....	4
	12. Fault Type .....	4
C.	Outage Initiation Codes .....	4
	1. Element-Initiated Outage .....	5
	2. Substation or Terminal-Initiated Outage.....	5
	3. Other Facility-Initiated Outage .....	5
D.	Outage Mode Codes .....	5
	1. Single Mode Outage.....	5
	2. Dependant Mode Initiating Outage .....	5
	3. Dependant Mode Outage.....	5
	4. Common Mode Outage .....	5
	5. Common Mode Initiating Outage .....	5
E.	Cause Codes Types.....	5
	1. Initiating Cause Code.....	5
	2. Sustained Cause Code.....	5
F.	Cause Codes.....	6
	1. Weather, excluding lightning .....	6
	2. Lightning .....	6
	3. Environmental.....	6
	4. Contamination.....	6
	5. Foreign Interference .....	6
	6. Fire .....	6
	7. Vandalism, Terrorism or Malicious Acts .....	6
	8. Failed Equipment .....	6
	9. Relay and/or Control Misoperation.....	6

10. Vegetation .....	6
11. Power System Condition.....	6
12. Human Error .....	7
13. Unknown.....	7
14. Other.....	7

## **A. TADS Population Definitions**

### **1. Element**

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

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

### **2. 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.

### **3. 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.

### **4. 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  $\geq 200$  kV such as surge arrestors, buses, Transformers, wave traps, potential and current transformers, relays, motorized devices, grounding switches, shunt or series capacitors, and reactors.

### **5. AC/DC Terminal**

A terminal that includes all AC and DC equipment needed for DC operation: 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.

### **6. 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.

### **7. DC Circuit**

One pole of an Overhead or Underground DC line operating at greater than  $+/- 200$  kV DC and which is bound by an AC/DC Terminal on each end.

### **8. 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.

### **9. 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.

### **10. 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.

### **11. Multi-Circuit Structure Mile**

A one-mile linear distance of sequential structures carrying multiple Overhead AC or DC Circuits.

### **12. 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 is triggered by an automatic protection device, resulting in a normally in-service Element that is not in an In-Service State; e.g., 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:**

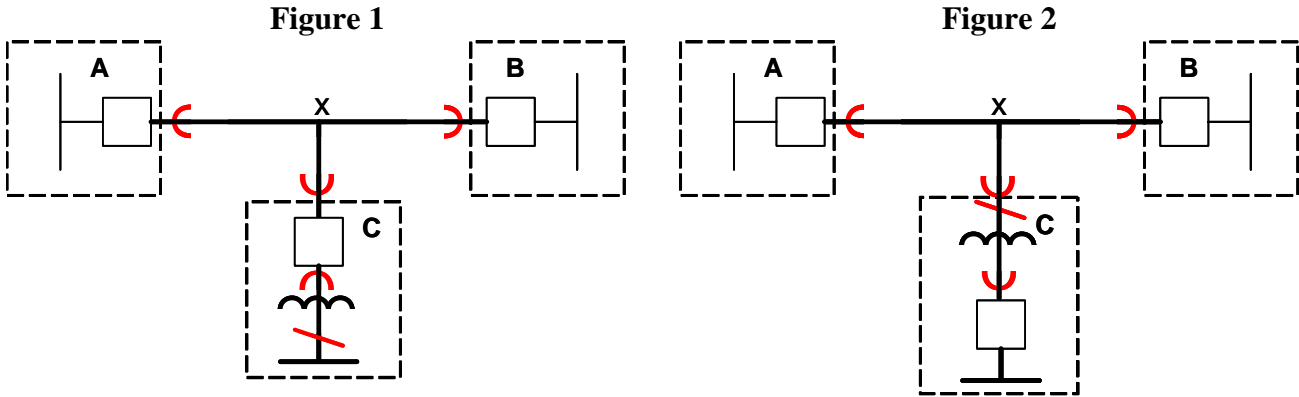
An Automatic Outage with an Outage Duration less than 1 minute. If the circuit recloses and trips again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered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

### **3. Sustained Outage:**

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

#### 4. In-Service State

An Element that is energized and fully connected to the system. An AC Circuit is considered to be in-service even though Transformers and their associated switching or interrupting devices are not in service. The illustrations below indicate the special handling of Transformers as they relate to an AC Circuit outage.



In both figures, the AC Circuit is bounded by AC Substations “A,” “B,” and “C” as indicated by the red arcs. Note that the Transformer in either figure may *or* may not be a TADS Transformer (i.e., one with a low-side voltage  $\geq 200$  kV). The Transformer’s boundaries are the red disconnect switch and the red arc before the breaker.

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.

#### 5. 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 the geography of 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.

#### 6. TO Element Identifier

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

#### 7. 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 Greenwich Mean Time [a.k.a., Coordinated Universal Time (UTC)], not local time.

#### 8. 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 Instructions address the recording of the Outage Durations of an Sustained Outage that starts in one calendar year and concludes in another calendar year.

**9. Event**

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

**10. Event Identification (ID) Code**

A unique alphanumeric identifier assigned by the Transmission Owner that to an Event. Because outages that begin in one reporting year and end in the next reporting year will 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 a Single Mode Automatic Outage with a will have a just one Event ID Code.
2. Each outage in a related set of two or more outages (e.g., Dependant Mode, Dependent Mode Initiating, Common Mode, or Common Mode Initiating) shall be given the same Event ID Code.

**11. 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 time.
20	B	Automatic Outage of a DC Circuit with normal clearing time.
30	C	Automatic Outage of two ADJACENT AC Circuits on the same structure with normal clearing time.
40	C	Automatic Outage of two ADJACENT DC Circuits on the same structure with normal clearing time.
50	NA	Other - please describe the event

**12. 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
3. Ground target
4. Both
5. Unknown.

**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. Substation or Terminal-Initiated Outage**

An Automatic Outage of an Element that is initiated on or within AC Substation facilities  $\geq 200$  kV (Substation-Initiated Outage) or an AC/DC Terminal facilities  $\geq 200$  kV (Terminal-Initiated Outage).

### **3. Other Facility-Initiated Outage**

An Automatic Outage that is initiated on or within other facilities  $< 200$  kV.

## **D. Outage Mode Codes**

### **1. Single Mode Outage**

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

### **2. Dependant Mode Initiating Outage**

A Single Mode Outage that initiates subsequent Automatic Outages.

### **3. Dependant Mode Outage**

An Automatic Outage of an Element which occurred as a result of an initiating outage, whether the initiating outage was an Elements outage or a non-Element 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.

## **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.

For example, a lightning strike on an AC Circuit (the Initiating Cause Code) that should have cleared normally may have become a Sustained Outage because of relay misoperation (the Sustained Cause Code). Momentary Outages do not have a Sustained Cause Code.

## **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, or dust storm.

### **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 not due to an error by a utility employee or contractor. See item 12, "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 Equipment**

Automatic Outages caused by the failure of equipment. Use this code only when the equipment failed even though it was operated within design specifications. The failed equipment could be (i) a component of an Element (such as a failed insulator), (ii) part of an AC Substation (such as a failed circuit breaker), or (iii) other facilities < 200 kV.

### **9. Relay and/or Control Misoperation**

Automatic Outages caused by relay and/or control initiated operations when not desired or the failure to operate when desired. This category also includes incorrect relay or control settings that do not coordinate with other protective devices.

### **10. Vegetation**

Automatic Outages caused by vegetation.

### **11. Power System Condition**

Automatic Outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, unique system configurations (e.g.,

an abnormal terminal configuration due to existing condition with one breaker already out of service).

**12. 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.

**13. Unknown**

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

**14. Other**

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

## 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.

<b>Collect Planned Outage Data Because:</b>	<b>Don't Collect Planned Outage Data Because:</b>
Most utilities collect planned outage data so little or no additional burden is imposed by requiring it to be reported. Without planned outage data, transmission system availability cannot be calculated, and a trend of this statistic is a useful indicator.	Trending system unavailability has a potential negative unintended consequence. Since planned outages comprise the largest part of unavailability, a Transmission Owner could maximize system availability by (a) reducing planned outages, which could (b) increase forced outages but (c) meet a goal of increased availability. 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. <sup>12</sup>	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.<sup>13</sup> Schedule 7 contains transmission outages data for AC circuits  $\geq 230$  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

<sup>12</sup> 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.

<sup>13</sup> 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 than 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).<sup>14</sup> 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 Failure (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.

<sup>14</sup> 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:

$$\frac{[(\text{No. of Elements} \times 8,760 \text{ hrs}) - \sum \text{Element Sustained Automatic Outage Hours} - \sum \text{Element Planned Outage Hours}]}{(\text{No. of Elements} \times 8,760 \text{ hrs})}$$

b. TADS Definition:

$$\frac{[(\text{No. of Elements} \times 8,760 \text{ hrs}) - \sum \text{Element Sustained Automatic Outage Hours}]}{(\text{No. of Elements} \times 8,760 \text{ hrs})}$$

2. Mean Time Between Failure

a. Normal Industry Definition:

$$\frac{[(\text{No. of Elements} \times 8,760 \text{ hrs}) - \sum \text{Element Sustained Automatic Outage Hours} - \sum \text{Element Planned Outage Hours}]}{(\text{No. of Sustained Element Outages})}$$

b. TADS Definition:

$$\frac{[(\text{No. of Elements} \times 8,760 \text{ hrs}) - \sum \text{Element Sustained Automatic Outage Hours}]}{(\text{No. of Sustained Element Outages})}$$

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.)	11,386	16,685	13,281	18,771
MTBF with Scheduled Outage Data (hrs.)	11,337	16,495	13,176	18,308

## Appendix 4 Metric Formulas

## General Formulas

No.	Metric	Formula	Units	Acronymn
<b><i>Element Outage Frequency</i></b>				
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
<b><i>Element Outage Duration, Repair Time, and Up Time</i></b>				
4	Element Sustained Outage Duration Time	Total Sustained Outage Hours / Total Elements	No. of Automatic Outages hours per Element per year	SODT
5	Element Sustained Outage Mean Time to Repair	Total Sustained Outage Hours / Total Sustained Element Outages	No. of Automatic Outage hours per Element outage per year	MTTR
6	Mean Time Between Sustained Element Outages (Mean "Up Time")	(Total Element Hours - Total Sustained Outage Hours) / Total Elements	Mean (average) no. of hours of operation of a Element before it fails	MTBF <sup>1</sup>
7	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 hours of operation of a Element before it fails	MdTTR
<b><i>Element Availability</i></b>				
8	Element Availability Percentage	1- (Total Sustained Outage Hours / Total Element Hours) * 100	Percentage	APC <sup>1</sup>
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 (either OE-417 or EOP-004)	Total Automatic Outages associated with a Disturbance Report / Total Automatic Outages	Percentage	PCDR

<sup>1</sup> 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)**

	<b>Metric</b>	<b>Formula</b>	<b>Units</b>	<b>Acronym</b>
	<b><i>Circuit Outage Frequency, per 100 Circuit Miles (Applies to AC and DC Circuits Only)</i></b>			
<b>11</b>	Circuit Total Outage Frequency, Mileage Adjusted	$(\text{Total Circuit Automatic Outages} * 100) / \text{Total Circuit Miles}$	No. Automatic Outages per 100 Circuit Miles per year	TCOF <sub>100CTmi</sub>
<b>12</b>	Circuit Sustained Outage Frequency, Mileage Adjusted	$(\text{Total Circuit Sustained Outages} * 100) / \text{Total Circuit Miles}$	No. Sustained Outages per 100 Circuit Miles per year	SCOF <sub>100CTmi</sub>
<b>13</b>	Circuit Momentary Outage Frequency, Mileage Adjusted	$(\text{Total Circuit Momentary Outages} * 100) / \text{Total Circuit Miles}$	No. Momentary Outages per 100 Circuit Miles per year	MCOF <sub>100CTmi</sub>
	<b><i>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.)</i></b>			
<b>14</b>	Multi Circuit Total Outage Frequency, Mileage Adjusted	$(\text{Total Multi-Circuit Automatic Outages} * 100) / \text{Total Multi-Circuit Structure Miles}$	No. Automatic Outages per 100 Multi-Circuit Structures Miles per year	TMCOF <sub>100STmi</sub>
<b>15</b>	Multi-Circuit Sustained Outage Frequency, Mileage Adjusted	$(\text{Total Multi-Circuit Sustained Outages} * 100) / \text{Total Multi-Circuit Structure Miles}$	No. Sustained Outages per 100 Multi-Circuit Structure Miles per year	SMCOF <sub>100STmi</sub>
<b>16</b>	Multi-Circuit Momentary Outage Frequency, Mileage Adjusted	$(\text{Total Multi-Circuit Momentary Outages} * 100) / \text{Total Multi-Circuit Structure Miles}$	No. Momentary Outages per 100 Multi-Circuit Structure Miles per year	MMCOF <sub>100STmi</sub>

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