NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Availability Data System Interim Report

Prepared by:

Transmission Availability Data System Task Force

For:

NERC Planning Committee

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1. The Task Force's Mission

The Transmission Availability Data System Task Force (TADSTF, or TF) was initiated by the Planning Committee's Executive Committee on October 27, 2006, with this purpose statement: [1]

> In order to quantify or measure system performance and reliability, the TADS Task Force will 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, the specified activities of the TF were as follows:

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 US and Canadian representation.[2] Three meetings and numerous conference calls were convened. The TF started its work by studying several existing transmission availability data collection models, and the resulting recommendations are largely built upon this body of work.[3] It was 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
  - ERO
  - Governmental bodies (FERC, EIA, etc.)

We expect the TADS reporting requirements to be made mandatory on all Transmission Owners (TOs) that are obligated to register with NERC for the

[1] From PC Chair Scott Helyer's letter announcing the formation of the TF.
[2] Members are listed in the NERC Roster, which is at http://www.nerc.com/~filez/roster.pdf
[3] The data collection frameworks we examined included those of the US Energy Information Administration (Form 411, Schedule 7), the Canadian Electricity Association, ECAR, WECC, and EPRI. In addition, TF members shared their own organization's approach to collecting transmission availability data.

reporting year 2008.[4] In addition, although TADS will be a NERC-wide requirement, Regional Entities (REs) may adopt more detailed reporting requirements. While we know that NERC and REs have the authority to require the collection of data it needs to implement their reliability mandates[5], existing NERC and RE rules may not yet provide the needed data request mechanisms. This is a legal issue that is beyond the scope of the TF.

Since this is an Interim Report, the descriptions that follow are at a high-level and often without the benefit of the underlying rationale. The report itself will have more detailed information. While capitalized terms are TADS definitions that will be fully defined in the Final Report, several critical terms are defined in this report.

2. Overall TADS Structure

a. We recommend collecting data on four specific transmission Elements which operate at 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). AC Circuits are defined as transmission lines bound by either (i) automatic protection devices (a.k.a. breaker-to-breaker) or (ii) automatic protection devices and a Transformer high-side terminal. Radial lines 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

b. The TF chose a framework that requires TOs to report aggregate transmission population inventory data by voltage class to their RE and also requires 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.).
   - However, each Element outage has specific data reporting requirements (described in Section 3).

c. We decided to report only Automatic Outages; i.e., outages triggered by automatic protection devices.

[4] We will have a provision allowing the TO to designate another entity, such as an RTO, to assume the TOs reporting obligation. This has not been developed.

[5] In the US, Volume18, 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."

- 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.

d. On the type of outages to include in TADS, the TF could not decide on the affirmative inclusion or exclusion of planned outage data. Therefore, our framework excludes planned outage data, and we expect this issue to be one that the Planning Committee will provide direction on before we prepare the Final Report. The Appendix describe the "pros and cons" on this topic as well as the impact of excluding planned outages has on certain metrics.

e. The TF 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. We decided to ask the TOs to report whether an OE-417 was filed that was associated with the Event ID.[6] The OE-417 is the Department of Energy's Electric Emergency Incident Report, and it only applies to US utilities.[7]

f. The TF agreed that data submitted by TOs would be confidential, 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. In addition, TADS public reports will not inadvertently release confidential information by the display of regional or NERC information from which a TO's data could be ascertained.[8]

g. The TF 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 this analysis will be used to improve planning and operations. Ultimately, all of these follow-up actions will result in improved transmission system performance. In addition, trending each region's performance against its own history will show how that region's performance is changing over time. This comparison is an appropriate benchmark. 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.), the TF strongly believes that comparisons for the purposes of identifying relative performance are not appropriate.

3. Required Element Inventory and Outage Data

Calendar-year data will be submitted to NERC in a process described in Section 5. Data submitted will identify the TO and its RE.

[6] The term "Event ID" is described in Section 3.c.1.
[7] The OE-417 is available at: http://www.eia.doe.gov/cneaf/electricity/page/forms.html
[8] 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 since the TO would be identifiable.

a. TOs will identify 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 will assure that a single TO is responsible for reporting.

b. For each voltage class of Elements[9], the following data will be reported:
   1. Year-end data on the number of Elements installed.
   2. The number of Element additions and retirements during the year.
   3. The 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.[10]
   4. The number of Elements with zero outages during the year.
   5. For AC and DC Circuits, the number of Circuit Miles.
   6. For AC Circuits, the data in lines 1-5 will also be reported for multi-circuit structures, with Structure Miles reported instead of Circuit Miles.[11]

c. For each Element outage, the following data will be reported:
   1. An Event ID. An Event is a transmission network incident that results in the Sustained or Momentary outage of one or more of the TADS population Elements. Each TO may assign their own Event ID. Data for each Event ID is described in paragraph d. below.
   2. The Fault Type (i.e., no fault, or phase targets and ground targets, or unknown)
   3. The Element's voltage class.
   4. For an AC and DC Circuit outage, whether the circuit is Overhead or Underground.
   5. For an AC Circuit outage, whether a Transformer is in the AC Circuit (Y/N).
   6. For a Transformer outage, whether the Transformer was connected within the AC Circuit.
   7. Whether the outage was Terminal (substation) initiated (Y/N).
   8. The outage start date and time, reported by all TOs in Greenwich Mean Time (GMT). 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. In addition a common time reference will allow REs and NERC to assign common Event IDs to Events that cross TO and RE boundaries.
   9. For Sustained Outages, the outage Duration shall be 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.
   10. An outage Cause Code. A Cause Code defines the outage cause such as lightning, equipment failure, relay mis-operation, etc.
   11. An Outage Mode. Several Outage Mode categories will be provided: Independent, Dependent, and Common.
       - An Independent Mode outage does not impact any other Elements.

[9] AC and DC Circuit data will be provided by voltage class in separate Overhead and Underground categories.
[10] Metrics are discussed in Section 4.
[11] Multi-circuit outages are recorded as an Event Type. See Section 3.d.1.

- A Dependent Mode outage involves two or more Momentary or Sustained outage Elements, one of which is the initiating outage.
- A Common Mode outage requires two or more Momentary or Sustained outages with identical Cause Codes. A Common Mode outage may initiate a subsequent Dependent outage.

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

1. The Event Type. Only five are proposed at this stage. These are shown on table below. More may be added as TADS matures.

Event Type	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 single pole of a DC Circuit with normal clearing time.
70	C	Automatic Outage of both poles of a DC Circuit with normal clearing time.
80	C	Loss of two **adjacent** AC Circuits on a multiple-circuit towerline with normal clearing time.
100	NA	Other - please describe the event

2. Whether the Event was associated with the filing of an OE-417 filing (Yes/No/Unknown), an answer applicable to US TOs only.

4. 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.

a. Given the type of data collected, several common metrics will be reported to describe the performance of each Element for the calendar reporting year:

1. Outage frequency & frequency/100 mi.[12]
2. Outage duration
3. Mean Time Between Failure -MTBF
4. Mean Time to Repair - MTTR (Sustained Outages only)
5. Median Time to Repair - MdTTR (Sustained Outages only)
6. Percent Availability
7. Percent of Elements w. zero outages
8. When possible, the standard deviation of metrics will be calculated.

b. Because planned outage data is not part of the TADS data, the definitions of MTBF and Percent Availability will be slightly overstated from industry definitions. The Appendix contains an analysis of this impact.

c. Given the richness of the data, the metrics described above 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 No., for each applicable OE-417 report, for all circuits on multi-circuit structures, and for various combinations of these. The TF has not established a comprehensive set of uniform metric calculations.

[12] Only circuits will have frequency/100 mi. calculated.

5. Data Collection, Analysis and Reporting Process

The TF recommends the process shown on the diagram on the page 8. It has three major component steps that are highlighted the large figures containing an A, B, or C. The TF has not completed discussion of the timeline for this process.

a. 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 regions only. This bundled data request is then sent from the each Regional Entity to the Transmission Owners in their region.

b. 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 data submitted by TOs and assign a common Event ID to Events that cross TO boundaries (if any). Common Events will be identified by near coincident Element outage start times or other 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 data and assign a common Event ID to Events that cross RE boundaries (if any).

c. 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 on 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.

For TADS data submitted by TOs to be comparable, consistent implementation of TADS across all TOs is critical. The TF recommends that NERC/REs take the role of training TOs (through workshops or other means) as well as auditing their collection procedures to insure consistency.

6. Next Steps

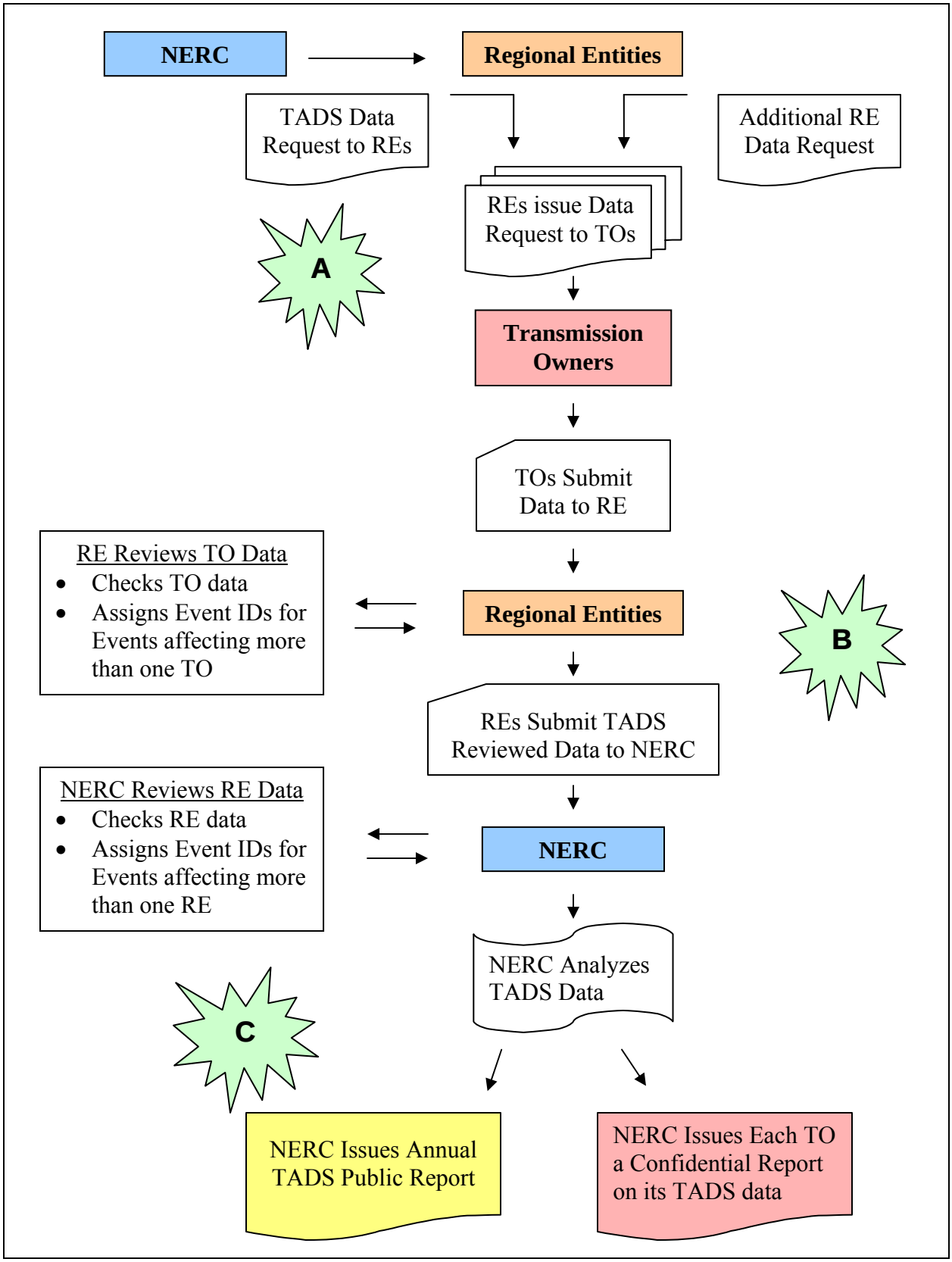
Although the TF has accomplished much in a short time, its work is not complete. The following describes the remaining schedule we envision.

TF Activity	Time Frame (2007)
Incorporate comments from the Planning Committee and identify TADS open issues requiring resolution to achieve 2008 implementation.	Late March
Review TADS with the Energy Information Administration and government users for their input.	By April 13
Evaluate alternatives for open issues and make decisions.	TF Meeting April 23-25
Complete Final Report for presentation at the Planning Committee's June meeting. All items except a draft implementation manual will be completed.	May 23
Complete draft implementation manual that will provide guidelines and examples	Mid July
Beta-test TADS with a small no. of TOs to identify implementation problems. Revise implementation manual as necessary.	September 1-30
Complete final implementation documentation.	October 31

Not shown on the schedule (because its exact timing is unknown) is the need to respond to EIA's Federal Register Notice for the re-authorization of their data collection forms. We expect this to come out in March, and NERC will have 60 days to respond. Schedule 7 on EIA Form 411 is of particular interest to the TF since it requests transmission availability data.[13]

[13] Form 411 is available at http://www.eia.doe.gov/cneaf/electricity/page/forms.html

TADS Process



Appendix: Planned Outage Data

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.[14]	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.[15] 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 included:

- ECAR
- 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

[14] 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.

[15] 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).[16] 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.

1. Percent Availability:
    a. Normal Industry Definition:

[16] 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."

[(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 Failure

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