



**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

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Order Instituting Rulemaking to
Update Rules for the Safety,
Reliability, and Resiliency of Electrical
Distribution Systems.

R.24-05-023

**SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) RESPONSE TO RULING
REQUESTING DRAFT PROPOSALS FROM RESPONDENTS AND STAKEHOLDERS
REGARDING DATA DEFINITION AND GUIDELINE ENHANCEMENTS**

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Dated: **December 13, 2024**

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TABLE OF CONTENTS

<u>Section</u>	<u>Title</u>	<u>Page</u>
I. INTRODUCTION		1
II. SCE COMMENTS ON SPECIFIC QUESTIONS TO ADDRESS		2
III. CONCLUSION.....		5
APPENDIX A SCE’S DRAFT PROPOSAL FOR DATA DEFINITIONS AND GUIDELINES		
APPENDIX B ANNUAL RELIABILITY REPORT		
APPENDIX C IEEE 1366-2022		
APPENDIX D NERC TADS		
APPENDIX E NATF DEFINITIONS		
APPENDIX F ANNUAL ELECTRIC POWER INDUSTRY REPORT (EIA 861)		

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Pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, Southern California Edison Company (SCE) submits this Response to the Administrative Law Judge's Ruling Requesting Draft Proposals From Respondents and Stakeholders Regarding Data Definition and Guideline Enhancements (ALJ Ruling), dated November 12, 2024.

I.

INTRODUCTION

SCE includes in these comments its responses to the five questions in the ALJ Ruling¹ as well as its required Data Definition and Guideline Proposal,² included as Appendix A to these comments. SCE notes its responses to the questions and Data Definition and Guideline Proposal are preliminary because several aspects of the Data Definition and Guideline require further clarification and discussions, which SCE anticipates will occur at the workshop. Once SCE obtains a better understanding of what the Commission is trying to achieve with certain aspects of the Data Definition and Guideline requirements, it can provide additional details and

¹ ALJ Ruling, pp. 7-8.

² *Id.*, pp. 8-9.

recommendations. SCE reserves the right to expand upon, modify, or supplement its comments as this proceeding advance, and the scope and issues are further developed.

II.

SCE COMMENTS ON SPECIFIC QUESTIONS TO ADDRESS

1. What enhancements and/or updates should the Commission request for utility reporting requirements and data submissions on the following areas: electric outages, circuit info, and extreme events?

It is unclear to SCE what information the Commission believes is missing from current reporting requirements and data submissions or how any additional potential electric outage, circuit info, and extreme event information would ultimately be used by the Commission. SCE would appreciate additional guidance on these topics before it can provide more specific responses.

Based on its current understanding of the Commission's intended reporting for outages, circuit information, and extreme events, SCE does not believe additional enhancements or updates to the Commission's utility reporting requirements and data submissions are necessary. SCE believes that its current requirements and submissions/reports, such as the Annual Electric Reliability Report, provide a sufficient amount of information on outages and worst performing circuits, including and excluding Major Event Days (MEDs).³ However, SCE will reconsider potential enhancements after getting a better understanding of the Commission's intentions at the workshop.

2. What thresholds or revisions to thresholds, if any, should be established to define reasonable reliability performance given weather conditions? For example, according to General Order 166, restoration time is presumed reasonable during a major outage if the event's Customer Average Interruption Index (CAIDI) is below 570 minutes.

³ It is not clear to SCE what "extreme events" means in the context of this question; however, MEDs could be considered an "extreme event."

Please see Appendix A (SCE's Draft Proposal for Data Definitions) for SCE's proposal for thresholds or revisions to thresholds to define reasonable reliability performance in light of weather conditions. SCE proposes implementing dynamic CAIDI thresholds that adjust in real-time or near real-time based on current weather data and forecasts. SCE looks forward to further discussing its proposal and considering other metrics, such as System Average Interruption Duration Index (SAIDI) or Momentary Average Interruption Frequency Index (MAIFI), in the workshops and/or technical working group meetings.

3. What data, data sets, and reporting requirements could aid the Commission in increasing the prioritization of equity for purposes of outage reporting? Examples of equity indices/data include but are not limited to: income, rent/mortgage, Medical Baseline Program customer or vulnerable customers who rely on electricity to operate life-support equipment, tools such as CalEnviroScreen, Healthy Places Index or Climate & Economic Justice Screening Tool, or others as needed.

SCE could not identify any currently-reported data, data sets or reporting requirements that it would recommend to aid the Commission in increasing the prioritization of equity in outage reporting. There are internal-only and publicly available data sets and metrics available related to either Commission customer programs (CARE, FERA, Medical Baseline, etc.) or other commonly used equity and impact variables such as income, climate resilience, etc. However, these data sets would need to be correlated to outages to geolocate and tag each utility's distribution system separately with each variable of interest in order to be able to conduct a geospatial analysis that correlates the two sets of data (equity data vs. outage data).

When SCE has previously looked at the potential for unintentional equity differences in outage occurrence or responses, no trends or patterns were found that suggested circuits serving a high percentage of low-income census tracts⁴ experienced outages that were noticeably higher in frequency than circuits in other census tracts. Further, there was no

⁴ State Department of Water Resources Disadvantaged Communities Mapping Tool's low-income data set (<https://gis.water.ca.gov/app/dacs/>).

discernible trend or pattern that suggested any disparity in the time spent to restore low-income customers compared with other customers.

SCE recommends that a discussion on this topic be held at the workshop to clearly define what problem a potential report is aiming to report on so that stakeholders can better consider potential solutions. If only an initial screening-level analysis is needed in order to identify if equity issues exist, it may be least impactful to utilize the CalEnviroscreen, Disadvantaged Vulnerable Communities, or the State Department of Water Resources Mapping Tool's census tract data set to conduct a one-time screening level analysis to determine if there appears to be any inequities, prior to considering any further analysis or reporting requirements.

4. What additional data should be shared with customers before, during, and after outages above what is currently available through customer outage portals and other customer outage communication channels? Please respond for outages for planned and unplanned events and for “blue-sky” days and specific reliability events such as Public Safety Power Shutdowns (PSPS), and outages associated with Fast Trip setting-related outages (also known as Enhanced Powerline Safety Settings, Fast Curve, and Sensitive Relay Profile), Major Event Days, etc.

At present, SCE provides pertinent details to customers before, during, and after outages whenever possible. Information related to planned outages is made available to impacted customers to give them ample opportunity to make alternative plans. SCE also provides updates on the outage until it is concluded. In the event of unplanned outages, SCE informs customers about their outage from the time it is confirmed through to restoration. On any given “blue-sky” day, SCE customers can review planned and unplanned outages across the SCE territory via SCE.com. The website, along with the mobile application and other messaging channels, provides current information during major events, storms, and Public Safety Power Shutoff (PSPS) events. SCE is committed to keeping customers reasonably informed under all conditions.

In recent years, feedback from both residential and non-residential customers on PSPS notifications suggests a need to evaluate the notification cadence to ensure customers are informed without feeling overwhelmed. Customers have indicated that the current notification cadence can be excessive. SCE is continually evaluating its approach and cadence in sharing information and providing notifications to help ensure that critical and useful information is provided in a way that meets our customers' needs and preferences while aligning with current requirements outlined by the Commission.

5. What data and reporting requirements identify impacts on environmental and social justice communities, including the extent to which data definitions for outage reporting impact the achievement of any of the nine goals of the Commission's Environmental and Social Justice Action Plan?

As mentioned in the response to Question 3, currently-reported outage variables such as outage frequency, outage length and restoration time are not associated with Environmental and Social Justice (ESJ) community locations. Therefore, to SCE's knowledge there is nothing currently available that would address this question. Further, as mentioned above, preliminary work suggests there are likely no disparities significant enough to warrant spending resources to track and review such data. Tracked outage data also does not contain information related to clean energy resources, air quality, health, climate resiliency, or workforce development opportunities. Therefore, the outage tracking data set does not appear to be a good match for tracking ESJ Action Plan goals. Other reports more closely aligned with ESJ Action Plan goals may contain more relevant data.

III.

CONCLUSION

SCE appreciates the opportunity to provide these comments and draft proposal on this Rulemaking, and asks that Commission incorporate SCE's comments and concerns.

Respectfully submitted,

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Appendix A

SCE's Draft Proposal for Data Definitions and Guidelines

SCE's Draft Proposal for Data Definitions and Guidelines

1. Proposal Summary

SCE's Proposal outlined below provides insight into existing data and reporting provided to the Commission or other entities, and well as opportunities for enhancements. This Proposal is preliminary due to several aspects of the Data Definition and Guidelines requiring further clarification and discussion, which SCE anticipates will occur at the workshop.

At this time, SCE has not identified specific modifications, changes, or enhancements to the existing data. However, SCE does propose a comprehensive framework/approach that takes into account the variability and severity of weather events, leveraging the CAIDI metric as an example.

Once SCE obtains a better understanding of what the Commission is trying to achieve with certain aspects of the Data Definition and Guideline requirements, it can provide additional details and recommendations.

2. Existing Reporting

2.1 Data/Reports on Outages and Reliability provided to the CPUC or Other Entities - Include a description of the Data/Report, Recipient, Reporting Cycle and Format

Name	Description	Recipient	Cycle	Format
Transmission Availability Data System (TADS)	Submission of transmission equipment availability and detailed information about individual outage events (TADS Reporting)	NERC	Quarterly (due 45 days after the end of the quarter)	Excel File
Annual Transmission Reliability Report	Voluntary Report – includes all data from TADS and outage details for non-BES transmission equipment	North America Transmission Forum (NATF)	Annually (due July) - Voluntary	Excel File
Electric System Reliability Annual Reports	CPUC Decision D.16-01-008 requires reporting of the previous year's electric reliability on the system and division levels	CPUC	Annually (due July)	Written Document
Annual City Reliability Reports	Reliability metrics and outage information for SCE distribution system broken down for each city, county, and tribe in SCE's service territory.	SCE Website	Annually - Voluntary	PowerPoint Presentation

Annual Electric Power Industry Report (EIA 861)	System inventories, SAIDI and SAIFI along with MED information.	US Energy Information Agency	Annually (due April)	Excel File
Sustainability Report	Public report published on SCE.com addresses SCE's plan to reach carbon neutrality by 2045 and reviews annual SAIDI, SAIFI, and CAIDI reliability metrics.	SCE Website	Annually	PDF
WMP QDR	Table 5, captures and categorizes all planned and unplanned outage events that occurred during the specified quarter.	Energy Safety	Quarterly	Excel File

2.2. Reporting to Customers – Data and information provided to customers during outages

SCE provides an interactive [Outage Map](#) to help customers quickly determine if their service address is affected by an outage, including when an outage is scheduled to start and/or estimated to end. From the SCE outage center webpage, customers can also sign up to receive alerts, get safety tips, and get quickly connected to important resources and support programs should they require additional assistance during an outage emergency. This includes SCE community resource centers and crew vehicle locations, hotel assistance, food banks, and cooling centers. The SCE outage center also provides tips for preparing for outages, and information on outage types.

2.3. Reporting to Customers – Data and information provided to customers about improvements to infrastructure servicing them.

SCE provides a link to our [Capital Improvement Plan Map](#) as a resource for our customers/stakeholders. The tool highlights key activities planned throughout our service territory and is not inclusive of all work being conducted by SCE. SCE makes every effort to refresh this tool monthly, but it may not fully reflect current information and is subject to change. Links to this map are included in the Annual City Reliability Reports available on the SCE website. Additionally, in the [About Us](#) section of the website, SCE shares information about technology advancements and projects in progress by county.

2.4. Existing Data Dictionaries (Provided as attachments)

- Annual Reliability Report [Appendix B]
- IEEE 1366-2022 [Appendix C]
- NERC TADS [Appendix D]
- NATF Definitions [Appendix E]¹
- Annual Electric Power Industry Report (EIA 861) - [Appendix F]

¹ This document is confidential. In order to minimize administrative burden to the CPUC and parties, we are not attaching the document, but we can produce or file it upon request in conformance with the CPUC's guidelines around submission of confidential materials.

3. Reporting Enhancements

3.1. Proposed modifications, changes or enhancements to the existing data and new data proposals

At this time, SCE has not identified specific modifications, changes, or enhancements to the existing data. However, SCE has reviewed the Data Variables and Data Layering specifications in Section 2.3 of the Ruling.² Table 3.1.a below identifies for each of the minimum data specifications whether they are included in an existing report and, if so, which report.

Table 3.1.a

Data Variable / Layer	In Existing Report? (Yes, No, or Partially)	If Yes or Partially, Which Report?	Notes
<i>Outage Incidents</i>			
i. Time, location, and duration of outage	Partially	• TADS • NATF • CPUC Annual Reliability Reports	TADS and NATF reporting include records for each outage with dates and durations but these are only for the transmission / substation systems and not distribution. The annual reliability report to the CPUC has dates and durations listed for distribution but for MEDs only
ii. Causes and environmental context (e.g., temperature, weather conditions, etc.)	Partially	N/A	Requires further clarification
iii. Program (e.g., Protective Equipment and Safety Device Settings, PSPS)	No	N/A	Requires further clarification
iv. Relevant reliability indices and factors to calculate these indices, such as CAIDI	Yes	• CPUC Annual Reliability Reports • Public City Reports • SCE.com • EIA 861	CPUC Annual reliability report provides the indices but for entire territory, distribution/transmission systems, and by district with and without MED days and for both planned and unplanned outages;

² Ruling, pp. 5-6.

			also includes SAIDI details for the top ten unplanned outages. City reports supply SAIDI, SAIFI, and MAIFI by city and circuit. EIA 861 reports on system inventories, SAIDI and SAIFI along with MED information.
<i>Circuits and Circuit Segments</i>			
i. Number of customers and other demographic information (e.g., MBL, tribal)	Partially	• CPUC Annual Reliability Reports • CPUC City Reports	City reports include number of customers per circuit but do not detail customer demographics. CPUC Annual reliability report has customer counts for Worst Performing Circuits (WPC) only
ii. Length of circuits / circuit segments	Partially	• TADS • NATF • CPUC Annual Reliability Report • EIA 861	TADS and NATF include inventories that include circuit miles for transmission circuits but not for distribution circuits and do not identify which segments are affected in an outage. The CPUC Annual Reliability Report includes circuit miles for the WPC circuits only. EIA 861 reports on system inventories for distribution.
iii. Characteristics of circuits, e.g. share undergrounded and operating voltage	Partially	• TADS • NATF • CPUC Annual Reliability Report	TADS and NATF include operating voltage for transmission circuits but not for distribution circuits. No underground or overhead information is shared although there are voluntary fields to share this information. SCE reports number of terminals per circuit. The CPUC Annual Reliability Report has underground and overhead percentages for WPC circuits only.

iv. Inspection and maintenance history of circuits, e.g. last maintenance date, age of critical electrical assets on the circuits or circuit segments	No	N/A	N/A
v. Lifespans and percentage(s) of Lifespans for critical electric assets on the circuits or circuit segments	No	N/A	Unclear what is being sought (SCE has age of asset information but does not have pre-defined lifespans for all assets)
vi. Relevant reliability indices and factors to calculate these indices, such as the average interruption frequency index (AIFI)	Partially	• CPUC Annual Reliability Reports • CPUC City Reports • EIA 861	CPUC Annual Reliability Report provides the following indices for SCE territory, distribution / transmission systems, and by district with and without MED days for both planned and unplanned outages (not by individual event): • SAIDI • SAIFI • MAIFI • CAIDI Also includes SAIDI details for the top ten unplanned outages. City reports supply SAIDI, SAIFI, and MAIFI by city and circuit. EIA 861 reports on system inventories, SAIDI and SAIFI along with MED information.
<i>Customer Experience</i>			
i. Number and duration of outages	No	N/A	Not currently reported on a per customer basis
ii. Types of outages, e.g., planned vs unplanned	Partially	• CPUC Annual Reliability Report	CPUC Annual Reliability Report includes district level indices of SAIDI, SAIFI, MAIFI, and CAIDI for planned and unplanned outages. Lacks historical planned outage detailed information before 2022.

iii. Number of customers experiencing 1, 4, 8 outages	No	N/A	Not currently reported
<i>Extreme Events</i>			
i. Spatial and temporal extent of events	Partially	CPUC Annual Reliability Reports	CPUC Annual Reliability Report provides information regarding MEDs only.
ii. Types of events, e.g. storm, flood, snow	No	N/A	Requires further clarification.
iii. Detail of events, e.g. heat wave defined by CalAdapt as a duration of four consecutive extreme heat days or warm nights when the daily maximum/minimum temperature is above the extreme heat threshold	No	N/A	Requires further clarification.
iv. Major Event Days (MED) or non-MED	Partially	- CPUC Annual Reliability Reports - EIA 861	CPUC Annual reliability report provides information regarding MEDs. EIA 861 reports on system inventories, SAIDI and SAIFI along with MED information.

Without a clearer understanding of what the Commission is seeking for some of the specifications, it is challenging to recommend a specific enhancement to an existing report or a new report altogether. Therefore, SCE recommends one of the goals of the workshop be for the Commission to specifically list out and describe the data fields it seeks (and explain why it seeks them) so that SCE and other stakeholders can identify whether and how they can be provided (either through existing reports, enhanced versions of existing reports, or new reports or other work product).

3.2. Data/Reports on Outages and Reliability provided to the CPUC or Other Entities

3.3. Reporting to Customers – Data and information provided to customers during outages

3.4. Reporting to Customers – Data and information provided to customers about improvements to infrastructure servicing them.

4. Proposed Thresholds for reporting

SCE proposes a comprehensive approach that takes into account the variability and severity of weather events. The goal is to help ensure that reliability performance metrics are both fair and reflective of the operational challenges posed by the different weather conditions. The framework leverages the Customer Average Interruption Index (CAIDI) as an example. SCE looks forward to exploring other metrics for consideration, such as System Average Interruption Duration Index (SAIDI) or Momentary Average Interruption Frequency Index (MAIFI), in the workshops and/or technical working group meetings.

4.1 Categorizing Weather Conditions

SCE recommends categorizing weather conditions /types of emergencies (i.e., fires, mudslides, earthquakes, landslides, etc.) into distinct levels such as mild, moderate, and severe. This categorization would be based on historical weather data and predictive models, allowing for a more nuanced understanding of the impact of weather on reliability performance. By defining specific thresholds for each category, we can make sure that performance evaluations are consistent and transparent.

4.2 Implementing Dynamic Thresholds

SCE proposes implementing dynamic thresholds that adjust in real-time or near real-time based on current weather data and forecasts. This approach allows for a more accurate assessment of reliability performance, as it accounts for the immediate conditions that crews are working under. Dynamic thresholds provide flexibility and help us tailor performance metrics to be relevant to the situation at hand.

4.3 Revising CAIDI Thresholds

The Customer Average Interruption Duration Index (CAIDI) is a critical metric for assessing reliability performance. SCE suggests introducing tiered CAIDI thresholds for different weather categories. For instance:

- Mild Weather: CAIDI < xxxx
- Moderate Weather: CAIDI < xxxx
- Severe Weather: CAIDI < xxxx

These tiered thresholds recognize the varying degrees of difficulty in restoring service under different weather conditions.

4.4 Adjusting Restoration Times

During severe weather events, it is reasonable to allow for extended restoration times due to the increased challenges, additional safety concerns, and resource constraints. SCE recommends a sliding scale for restoration time thresholds that correlates with the severity and duration of the weather event. This approach helps make sure that restoration efforts are evaluated fairly and consistently, considering the operational realities faced by utility crews.

4.5 Regular Performance Reviews

To help ensure the effectiveness of the established thresholds, SCE proposes conducting regular reviews of reliability performance data. These reviews will help identify any necessary adjustments to the thresholds based on evolving weather patterns, technological advancements, and operational capabilities. Continuous improvement is key to maintaining a robust and fair reliability performance framework.

4.6 Stakeholder Engagement

SCE recognizes the importance of engaging with stakeholders, including customers, regulatory bodies, and industry experts. Gathering feedback from these groups will help ensure that the thresholds align with expectations and best practices. Stakeholder engagement fosters transparency and builds trust in the reliability performance evaluation process.

By proposing these measures, SCE aims to create a more balanced and useful framework for evaluating reliability performance. This approach ensures that restoration efforts are reasonable and reflective of the challenges posed by varying weather conditions, ultimately enhancing the resilience and reliability of our electric utility services.

5. Proposals to Align and enhance timing of reporting cycle

At this time, SCE has not identified firm opportunities to enhance the timing of reporting cycles. However, SCE anticipates that discussion of this topic at the workshop may yield some enhancement opportunities.

6. Maintenance and Modification of the Outage Data Set

It is unclear to SCE what the Commission's intent is for this section. We look forward to further discussion and clarification at the workshop.

Appendix B

Annual Reliability Report

APPENDIX A: Definitions

Outages are defined as an interruption to electric services. The type of outages falls in 4 different categories:

1. Unplanned outages: Unplanned outages are also known as repair outages. These outages occur without warning or notification of interruption of service.
 - a. Sustained Outages: Sustained outage is a subcategory of unplanned outages where the outage duration is greater than 5 minutes.
 - b. Momentary Outages: Momentary outage is a subcategory of unplanned outages where the outage duration is equal to or less than 5 minutes.
2. Planned outages: Planned outages are also known as maintenance outages. Maintenance outages would occur with notifications prior to interruption of service.
3. Public Safety Power Shutoff (PSPS): An operational protocol that is implemented under extreme weather conditions to minimize the threat of wildfires and keep communities safe from potentially dangerous situations. These types of sustained outages are temporary and usually involve situations where high-fire areas are experiencing adverse weather or public safety is at risk.
4. Major Event Day (MED): A day in which the daily system SAIDI exceeds a threshold value of T_{MED} . For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than a threshold value are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Events are excluded based on the "2.5 beta method." Per *IEEE Standard 1366*, days are excluded from a given year's indices if their SAIDI exceeds 2.5 times the standard deviation of the natural logarithm of daily SAIDI over the previous five-year period.
 - a. T_{MED} : The calculated threshold value used to determine a Major Event Day. SCE's T_{MED} value is calculated at the beginning of each year using SCE's daily SAIDI values for the prior 5 years. SCE's T_{MED} value for 2023 was 2.15 minutes.

SAIDI: The System Average Interruption Duration Index is the amount of time on average a customer was without power in a year due to sustained interruptions (measured in minutes per customer).

$$CELIDt = \frac{\text{total number of customers experiencing sustained interruptions longer than } t}{\text{total number of customer served}}$$

SAIFI: The System Average Interruption Frequency Index is the number of times an average customer was without power in a year due to service interruptions lasting more than 5 minutes (measured in interruptions per customer).

$$\text{SAIFI} = \frac{\text{sum of total quantity of sustained customer interruptions}}{\text{total number of customer served}}$$

MAIFI: The Momentary Average Interruption Frequency Index is the number of times an average customer was without power in a year due to service interruptions lasting 5 minutes or less (measured in interruptions per customer). SCE calculates MAIFI at the individual outage event.

$$\text{MAIFI} = \frac{\text{sum of total quantity of momentary customer interruptions}}{\text{total number of customer served}}$$

CAIDI: The average time required to restore service for a sustained outage.

$$\text{CEMIn} = \frac{\text{total number of customers experiencing n or more interruptions}}{\text{sum of total quantity of sustained customer interruptions}}$$

Circuit SAIFI: The number of times an average customer was without power in a year due to service interruptions lasting more than 5 minutes (measured in interruptions per customer). Circuit reliability indices are calculated using the average number of customers on that circuit as the number of total customers served for that specific circuit.

$$\text{Circuit SAIFI} = \frac{\text{sum of total quantity of sustained customer interruptions}}{\text{average number of customers on a circuit}}$$

Circuit SAIDI: The amount of time on average a customer was without power in a year due to sustained interruptions (measured in minutes per customer). Circuit reliability indices are calculated using the average number of customers on that circuit as the number of total customers served for that specific circuit.

$$\text{Circuit SAIDI} = \frac{\text{sum of all sustained customer interruption durations}}{\text{average number of customers on a circuit}}$$

Circuit MAIFI: The Momentary Average Interruption Frequency Index is the number of times an average customer was without power in a year due to service interruptions lasting 5 minutes or less (measured in interruptions per customer). SCE calculates MAIFI at the individual outage event. Circuit reliability indices are calculated using the average number of customers on that circuit as the number of total customers served for that specific circuit.

$$\text{Circuit MAIFI} = \frac{\text{sum of total quantity of momentary customer interruptions}}{\text{average number of customers on a circuit}}$$

Circuit CAIDI: The average time required to restore service for a sustained outage for that circuit.

$$\text{Circuit CAIDI} = \frac{\text{sum of all sustained customer interruption durations}}{\text{sum of total quantity of sustained customer interruptions}}$$

Appendix C
IEEE 1366-2022

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power & Energy Society

Sponsored by the
Transmission and Distribution Committee

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std 1366™-2012
(Revision of
IEEE Std 1366-2003)

31 May 2012

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IEEE Guide for Electric Power Distribution Reliability Indices

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**Transmission and Distribution Committee
of the
IEEE Power & Energy Society**

Approved 14 May 2012

IEEE-SA Standards Board

Abstract: Distribution reliability indices and factors that affect their calculations are defined in this guide. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.

Keywords: circuits, distribution reliability indices, distribution systems, electric power, IEEE 1366, reliability indices

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Introduction

This introduction is not part of IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

This guide was originally developed in 1998 to create indices specifically designed for distribution systems. Other groups have created indices for transmission and industrial systems, but none were available for distribution. This group will continue working in this area by refining the information contained in this guide.

This guide was updated in the 2003 revision to clarify existing definitions and to introduce a statistically based definition for classification of Major Event Days. The working group created a methodology, 2.5 Beta Method, for determination of Major Event Days. Once days are classified as normal or Major Event Days, appropriate analysis and reporting can be conducted.

This 2012 revision of the guide clarified several of the definitions and introduced two new indices. The new indices are CELID-s and CELID-t, customers experiencing long interruption durations (both single and total). A section was also added to explain the investigation of catastrophic days.

Content

1. Overview.....	1
1.1 Introduction.....	1
1.2 Scope	1
1.3 Purpose	1
2. Definitions	2
3. Definitions of reliability indices.....	4
3.1 Basic factors.....	4
3.2 Sustained interruption indices	5
3.3 Load based indices	8
3.4 Other indices (momentary).....	9
3.5 Major Event Day classification.	10
4. Application of the indices	13
4.1 Sample system	14
4.2 Calculation of indices for a system with no Major Event Days.....	15
4.3 Examples.....	17
5. Information about the factors that affect the calculation of reliability indices.....	19
5.1 Rationale behind selecting the indices provided in this guide	19
5.2 Factors that cause variation in reported indices.....	19
5.3 Major Event Days and catastrophic days	19
Annex A (informative) Bibliography	21
Annex B (informative) Major event definition development	22
Annex C (informative) Internal data subset	31

IEEE Guide for Electric Power Distribution Reliability Indices

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1. Overview

1.1 Introduction

This full-use guide has been updated to clarify existing definitions, introduce two additional reliability indices, and add a discussion of Major Event Days and catastrophic days (see 5.3).

1.2 Scope

This guide identifies distribution reliability indices and factors that affect their calculation. It includes indices, which are useful today, as well as ones that may be useful in the future. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.

1.3 Purpose

The purpose of this guide is twofold. First, it is to present a set of terms and definitions which can be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities. Secondly, it is to provide guidance for new personnel in the reliability area and to provide tools for internal as well as external comparisons. In the past, other groups have defined reliability indices for transmission, generation, and

distribution but some of the definitions already in use are not specific enough to be wholly adopted for distribution. Users of this guide should recognize that not all utilities would have the data available to calculate all the indices.

2. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary: Glossary of Terms and Definitions*¹ should be consulted for terms not defined in this clause.

connected load: Connected transformer or metered demand (to be clearly specified when reporting) on the circuit or portion of circuit that is interrupted. When reporting, the report should state whether it is based on an annual peak or on a reporting period peak.

customer: A metered electrical service point for which an active bill account is established at a specific location.

customer count: The number of customers either served or interrupted, depending on usage.

distribution system: That portion of an electric system that delivers electric energy from transformation points on the transmission system to the customer.

NOTE—The distribution system is generally considered to be anything from the distribution substation fence to the customer meter. Often the initial overcurrent protection and voltage regulators are within the substation fence and are considered part of the distribution system.²

forced outage: The state of a component when it is not available to perform its intended function due to an unplanned event directly associated with that component.

interrupting device: A device to stop the flow of power, usually in response to a fault. Operation of the device can be accomplished by manual, automatic, or remotely operated methods. Examples include circuit breakers, line reclosers, line fuses, disconnect switches, sectionalizers, and/or others.

interruption: The total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system. This does not include any of the power quality issues such as: sags, swells, impulses, or harmonics. *See also:* **outage**.

interruption duration: The time period from the initiation of an interruption until service has been restored to the affected customers.

NOTE—The process of restoration may require restoring service to small sections of the system until service has been restored to all customers. See 4.3.2 for a step-restoration example. Each of these individual steps should be tracked, collecting the start time, end time, and number of customers interrupted for each step.

interruptions caused by events outside of the distribution system: Outages that occur on generation, transmission, substations, or customer facilities that result in the interruption of service to one or more customers. While generally a small portion of the number of interruption events, these interruptions can affect a large number of customers and may last for a long time.

lockout: When a reclosing interrupting device is in the open position and no further operations of that device are allowed without manual intervention.

¹ *IEEE Standards Dictionary: Glossary of Terms and Definitions* is available at <http://shop.ieee.org>.

² Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

Major Event: Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day. *See also:* **Major Event Day**.

Major Event Day (MED): A day in which the daily system System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather). Activities that occur on Major Event Days should be separately analyzed and reported.

NOTE—See Major Event Day classification in 3.5.

momentary interruption: The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device.

NOTE—Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.

momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device.

NOTE 1—Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption.

NOTE 2—If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

outage: The loss of ability of a component to deliver power.

NOTE 1—An outage may or may not cause an interruption of service to customers, depending on system configuration.

NOTE 2—This definition derives from transmission and distribution applications and does not apply to generation outages.

planned interruption: The loss of electric power to one or more customers that results from a planned outage.

NOTE 1—This derives from transmission and distribution applications and does not apply to generation interruptions.

NOTE 2—The key test to determine if an interruption should be classified as a planned or unplanned interruption is as follows: If it is possible to defer the interruption, then the interruption is a planned interruption; otherwise, the interruption is an unplanned interruption.

planned outage: The intentional disabling of a component's capability to deliver power, done at a pre-selected time, usually for the purposes of construction, preventative maintenance, or repair.

reporting period: The time period from which interruption data is to be included in reliability index calculations. The beginning and end dates and times should be clearly indicated. All events that begin within the indicated time period should be included. A consistent reporting period should be used when comparing the performance of different distribution systems (typically one calendar year) or when comparing the performance of a single distribution system over an extended period of time. The reporting period is assumed to be one year, unless otherwise stated.

step restoration: The process of restoring all interrupted customers in stages over time.

sustained interruption: Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes.

total number of customers served: The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report.

unplanned interruption: The loss of electric power to one or more customers that does not result from a planned outage.

3. Definitions of reliability indices

3.1 Basic factors

The basic factors defined below specify the data needed to calculate the reliability indices.

NOTE—The subscript ‘i’ denotes an interruption event.

CI	Customers interrupted
CMI	Customer minutes of interruption
CN	Total number of distinct customers who have experienced a sustained interruption during the reporting period
CN_(k≥n)	Total number of customers who have experienced <i>n</i> or more sustained interruptions during the reporting period
CN_(k≥S)	Total number of customers that experienced <i>S</i> or more hours duration
CN_(k≥T)	Total number of customers that experienced <i>T</i> or more hours duration
CNT_(k≥n)	Total number of customers who have experienced <i>n</i> or more sustained interruptions and momentary interruption events during the reporting period
E	Event
IM_i	Number of momentary interruptions
IM_E	Number of momentary interruption events
k	Number of interruptions experienced by an individual customer in the reporting period
L_i	Connected kVA load interrupted for each interruption event
L_T	Total connected kVA load served
N_i	Number of interrupted customers for each sustained interruption event during the reporting period
N_{mi}	Number of interrupted customers for each momentary interruption event during the reporting period

N_T	Total number of customers served for the area
r_i	Restoration time for each interruption event
T_{MED}	Major Event Day threshold

3.2 Sustained interruption indices

3.2.1 SAIFI: System Average Interruption Frequency Index

The System Average Interruption Frequency Index (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in Eq. (1).

$$SAIFI = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \quad (1)$$

To calculate the index, use Eq. (2).

$$SAIFI = \frac{\frac{\sum N_i}{N_T}}{\frac{CI}{N_T}} \quad (2)$$

3.2.2 SAIDI: System Average Interruption Duration Index

The System Average Interruption Duration Index (SAIDI) indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in minutes or hours of interruption. Mathematically, this is given in Eq. (3).

$$SAIDI = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}} \quad (3)$$

To calculate the index, use Eq. (4).

$$SAIDI = \frac{\frac{\sum r_i N_i}{N_T}}{\frac{CMI}{N_T}} \quad (4)$$

3.2.3 CAIDI: Customer Average Interruption Duration Index

The Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service. Mathematically, this is given in Eq. (5).

$$CAIDI = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}} = \frac{CMI}{CI} \quad (5)$$

To calculate the index, use Eq. (6).

$$CAIDI = \frac{\sum_i r_i N_i}{\sum_i N_i} = \frac{SAIDI}{SAIFI} \quad (6)$$

3.2.4 CTAIDI: Customer Total Average Interruption Duration Index

The Customer Total Average Interruption Duration Index (CTAIDI) represents the total time in the reporting period that average customers who actually experienced an interruption were without power. This index is a hybrid of CAIDI and is similarly calculated, except that those customers with multiple interruptions are counted only once. Mathematically, this is given in Eq. (7).

$$CTAIDI = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Distinct Customers Interrupted}} \quad (7)$$

To calculate the index, use Eq. (8).

$$CTAIDI = \frac{\sum_i r_i N_i}{CN} = \frac{CMI}{CN} \quad (8)$$

NOTE—In tallying Total Number of Customers Interrupted, each individual customer should be counted only once regardless of the number of times interrupted during the reporting period. This applies to definitions provided in 3.2.4 and 3.2.5.

3.2.5 CAIFI: Customer Average Interruption Frequency Index

The Customer Average Interruption Frequency Index (CAIFI) gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once, regardless of the number of times interrupted for this calculation. Mathematically, this is given in Eq. (9).

$$CAIFI = \frac{\sum \text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}} \quad (9)$$

To calculate the index, use Eq. (10).

$$CAIFI = \frac{\sum_i N_i}{CN} = \frac{CI}{CN} \quad (10)$$

3.2.6 ASAI: Average Service Availability Index

The Average Service Availability Index (ASAI) represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. Mathematically, this is given in Eq. (11).

$$ASAI = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}} \quad (11)$$

To calculate the index, use Eq. (12).

$$ASAI = \frac{N_T \times (\text{Number of hours/yr}) - \sum_i r_i N_i}{N_T \times (\text{Number of hours/yr})} \quad (12)$$

NOTE—There are 8 760 hours in a non-leap year and 8 784 hours in a leap year.

3.2.7 CEMI_n: Customers Experiencing Multiple Interruptions

The Customers Experiencing Multiple Interruptions Index (CEMI_n) indicates the ratio of individual customers experiencing n or more sustained interruptions to the total number of customers served. Mathematically, this is given in Eq. (13).

$$CEMI_n = \frac{\text{Total Number of Customers that experienced } n \text{ or more sustained interruptions}}{\text{Total Number of Customers Served}} \quad (13)$$

To calculate the index, use Eq. (14).

$$CEMI_n = \frac{CN_{(k \geq n)}}{N_T} \quad (14)$$

NOTE—This index is often used in a series of calculations with n incremented from a value of 1 to the highest value of interest.

3.2.8 CELID: Customers Experiencing Long Interruption Durations

The Customers Experiencing Long Interruption Durations Index (CELID) indicates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time. That time is either the duration of a single interruption (s) or the total amount of time (t) that a customer has been interrupted during the reporting period. Mathematically, the Single Interruption Duration equation is given in Eq. (15) and the Total Interruption Duration equation is given in Eq. (17).

Single Interruption Duration:

$$CELID-t = \frac{\text{Total Number of Customers that experienced } S \text{ or more hours duration}}{\text{Total Number of Customers Served}} \quad (15)$$

To calculate the index, use Eq. (16).

$$CELID-s = \frac{CN_{(k \geq S)}}{N_T} \quad (16)$$

Total Interruption Duration:

$$\text{CELID-t} = \frac{\text{Total Number of Customers that experienced T or more hours duration}}{\text{Total Number of Customers Served}} \quad (17)$$

To calculate the index, use Eq. (18).

$$\text{CELID-t} = \frac{N_{(k \geq T)}}{N_T} \quad (18)$$

3.3 Load based indices

3.3.1 ASIFI: Average System Interruption Frequency Index

The calculation of the Average System Interruption Frequency Index (ASIFI) is based on load rather than customers affected. ASIFI is sometimes used to measure distribution performance in areas that serve relatively few customers that have relatively large concentrations of load, predominantly industrial/commercial customers. Theoretically, in a system with homogeneous load distribution, ASIFI would be the same as SAIFI. Mathematically, this ASIFI is given in Eq. (19).

$$\text{ASIFI} = \frac{\sum \text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}} \quad (19)$$

To calculate the index, use Eq. (20).

$$\text{ASIFI} = \frac{\sum L_i}{L_T} \quad (20)$$

3.3.2 ASIDI: Average System Interruption Duration Index

The calculation of the Average System Interruption Duration Index (ASIDI) is based on load rather than customers affected. Its use, limitations, and philosophy are stated in the ASIFI definition in 3.3.1. Mathematically, ASIDI is given in Eq. (21).

$$\text{ASIDI} = \frac{\sum \text{Connected kVA Duration of Load Interrupted}}{\text{Total Connected kVA Served}} \quad (21)$$

To calculate the index, use Eq. (22).

$$\text{ASIDI} = \frac{\sum r_i L_i}{L_T} \quad (22)$$

3.4 Other indices (momentary)

3.4.1 MAIFI: Momentary Average Interruption Frequency Index

The Momentary Average Interruption Frequency Index (MAIFI) indicates the average frequency of momentary interruptions. Mathematically, this is given in Eq. (23).

$$\text{MAIFI} = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}} \quad (23)$$

To calculate the index, use Eq. (24).

$$\text{MAIFI} = \frac{\sum \text{IM}_i \text{N}_{mi}}{\text{N}_T} \quad (24)$$

3.4.2 MAIFI_E: Momentary Average Interruption Event Frequency Index

The Momentary Average Interruption Event Frequency Index (MAIFI_E) indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a sustained interruption. Mathematically, this is given in Eq. (25).

$$\text{MAIFI}_E = \frac{\sum \text{Total Number of Customer Momentary Interruption Events}}{\text{Total Number of Customers Served}} \quad (25)$$

To calculate the index, use Eq. (26).

$$\text{MAIFI}_E = \frac{\sum \text{IM}_E \text{N}_{mi}}{\text{N}_T} \quad (26)$$

3.4.3 CEMSMI_n: Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events

The Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events Index (CEMSMI_n) is the ratio of individual customers experiencing n or more of both sustained interruptions and momentary interruption events to the total customers served. Its purpose is to help identify customer issues that cannot be observed by using averages. Mathematically, this is given in Eq. (27).

$$\text{CEMSMI}_n = \frac{\text{Total Number of Customers Experiencing } n \text{ or More Interruptions}}{\text{Total Number of Customers Served}} \quad (27)$$

To calculate the index, use Eq. (28).

$$\text{CEMSMI}_n = \frac{\text{CNT}_{(k \geq n)}}{\text{N}_T} \quad (28)$$

3.5 Major Event Day classification

The following process—Beta Method—is used to identify Major Event Days (MED), provided that the natural log transformation of the data results closely resembles a Gaussian (normal) distribution. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. For more technical detail on derivation of the methodology, refer to Annex B.

A MED is a day in which the daily system SAIDI exceeds a threshold value, T_{MED} . The SAIDI index is used as the basis of this definition since it leads to consistent results regardless of utility size, and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine the MEDs, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.

The MED identification T_{MED} value is calculated at the end of each reporting period (typically one year) for use during the next reporting period, as follows:

- a) Collect values of daily SAIDI for five sequential years, ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
- b) Only those days that have a SAIDI/Day value will be used to calculate T_{MED} (do not include days that did not have any interruptions).
- c) Take the natural logarithm ($\ln$) of each daily SAIDI value in the data set.
- d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
- e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
- f) Compute the MED threshold, T_{MED} , using Eq. (29).

$$T_{MED} = e^{(\alpha + 2.5\beta)} \quad (29)$$

- g) Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a MED.

Activities that occur on days classified as MEDs should be separately analyzed and reported.

3.5.1 An example of using the MED definition to identify major events and subsequently calculate adjusted indices that reflect normal operating performance

The following example illustrates the calculation of the daily SAIDI, calculation of the MED threshold T_{MED} , identification of MEDs, and calculation of adjusted indices.

Table 1 gives selected data for all interruptions occurring on a certain day for a utility that serves 2 000 customers.

Table 1—Interruption data for March 18, 1994

Date	Time	Duration (min)	Number of customers	Interruption Type
Mar 18, 1994	18:34:30	20.0	200	Sustained
Mar 18, 1994	18:38:30	1.0	400	Momentary
Mar 18, 1994	18:42:00	513.5	700	Sustained

Note that although the third interruption (at 18:42:00) was not restored until the following day, its total duration counts in the day that the interruption began. Note also that SAIDI considers only sustained interruptions.

For March 18, 1994, daily SAIDI (assuming a 2 000 customer utility) is given in Eq. (30).

$$\text{SAIDI} = \frac{(20 \times 200) + (513.5 \times 700)}{2000} = 181.73 \text{ min} \quad (30)$$

One month of historical daily SAIDI data is used in the following example to calculate the MED threshold T_{MED} . Five years of historical data is preferable for this method, but printing that many values in this guide is impractical, so only one month is used to illustrate the concept. The example data is shown in Table 2.

Table 2—One month of daily SAIDI and ln(SAIDI/day) data

Date	SAIDI/day (min)	ln(SAIDI/day)	Date	SAIDI/day (min)	ln(SAIDI/day)
Dec 1, 1993	26.974	3.295	Dec 17, 1993	0.329	-1.112
Dec 2, 1993	0.956	-0.046	Dec 18, 1993	0	This day is not included in the calculations since no customers were interrupted.
Dec 3, 1993	0.131	-2.033	Dec 19, 1993	0.281	-1.268
Dec 4, 1993	1.292	0.256	Dec 20, 1993	1.810	0.593
Dec 5, 1993	4.250	1.447	Dec 21, 1993	0.250	-1.388
Dec 6, 1993	0.119	-2.127	Dec 22, 1993	0.021	-3.876
Dec 7, 1993	0.130	-2.042	Dec 23, 1993	1.233	0.209
Dec 8, 1993	12.883	2.556	Dec 24, 1993	0.996	-0.004
Dec 9, 1993	0.226	-1.487	Dec 25, 1993	0.162	-1.818
Dec 10, 1993	13.864	2.629	Dec 26, 1993	0.288	-1.244
Dec 11, 1993	0.015	-4.232	Dec 27, 1993	0.535	-0.626
Dec 12, 1993	1.788	0.581	Dec 28, 1993	0.291	-1.234
Dec 13, 1993	0.410	-0.891	Dec 29, 1993	0.600	-0.511
Dec 14, 1993	0.007	-4.967	Dec 30, 1993	1.750	0.560
Dec 15, 1993	1.124	0.117	Dec 31, 1993	3.622	1.287
Dec 16, 1993	1.951	0.668			

NOTE—The SAIDI/day for December 18, 1993 is zero, and the natural logarithm of zero is undefined. Therefore, December 18, 1993 is not considered during the analysis.

The value of α , the log-average, is the average of the natural logs, and equals -0.555 in this case.

The value of β , the log-standard deviation, is the standard deviation of the natural logs, and equals 1.90 in this example.

The value of $\alpha + 2.5\beta$ is 4.20.

The threshold value T_{MED} is calculated by $e^{(4.20)}$ and equals 66.69 SAIDI minutes per day. This value is used to evaluate the future time period (e.g., the next year).

Table 3 shows example SAIDI/day values for the first month of 1994.

Table 3—Daily SAIDI data, January 1994

Date	SAIDI/Day	Date	SAIDI/Day
Jan 1, 1994	0.240	Jan 17, 1994	5.700
Jan 2, 1994	0.014	Jan 18, 1994	0.109
Jan 3, 1994	0.075	Jan 19, 1994	0.259
Jan 4, 1994	2.649	Jan 20, 1994	1.142
Jan 5, 1994	0.666	Jan 21, 1994	0.262
Jan 6, 1994	0.189	Jan 22, 1994	0.044
Jan 7, 1994	0.009	Jan 23, 1994	0.243
Jan 8, 1994	1.117	Jan 24, 1994	5.932
Jan 9, 1994	0.111	Jan 25, 1994	2.698
Jan 10, 1994	8.683	Jan 26, 1994	5.894
Jan 11, 1994	0.277	Jan 27, 1994	0.408
Jan 12, 1994	0.057	Jan 28, 1994	237.493
Jan 13, 1994	0.974	Jan 29, 1994	2.730
Jan 14, 1994	0.150	Jan 30, 1994	8.110
Jan 15, 1994	0.633	Jan 31, 1994	0.046
Jan 16, 1994	0.434		

The SAIDI/day on January 28, 1994 (237.49) exceeds the example threshold value ($T_{MED} = 66.69$), indicating that the distribution system experienced stresses beyond that normally expected on that day. Therefore, January 28, 1994 is classified as a MED. The SAIDI/day for all other days was less than T_{MED} , indicating that normal stresses were experienced on those days.

To complete the example, indices should be calculated for two conditions:

- 1) All events included
- 2) MEDs removed

In most cases, utilities will calculate all of the indices they normally use (e.g., SAIFI, SAIDI, and/or CAIDI). For this example, only SAIDI will be shown. The SAIDI for 1994 for condition 1) above (all events included) is given in Eq. 31.

$$SAIDI = \sum \text{Daily SAIDI} = 287.35 \quad (31)$$

The SAIDI for 1994 for condition 2) above (MEDs removed), for separate reporting and analysis, is given in Eq. 32.

$$SAIDI = \sum \text{Daily SAIDI with the MEDs removed} = 49.86 \quad (32)$$

4. Application of the indices

Most utilities store interruption data in large computer databases. Some databases are better organized than others for querying and analyzing reliability data. The following subclause will show one sample partial database and the methodology for calculating indices based on the information provided.

4.1 Sample system

Table 4 shows an excerpt from one utility's customer information system (CIS) database for feeder 7075, which serves 2 000 customers with a total load of 4 MW. In this example, Circuit 7075 constitutes the “system” for which the indices are calculated. More typically, the “system” combines all circuits together in a region or for a whole company.

Table 4—Interruption data for 1994

Date	Time	Time on	Circuit	Event code	Number of customers	Load kVA	Interruption type
Mar 17	12:12:20	12:20:30	7075	107	200	800	S
Apr 15	18:23:56	18:24:26	7075	256	400	1 600	M
May 5	00:23:10	01:34:29	7075	435	600	1 800	S
Jun 12	23:17:00	23:47:14	7075	567	25	75	S
Jul 6	09:30:10	09:31:10	7075	678	2 000	4 000	M
Aug 20	15:45:39	20:12:50	7075	832	90	500	S
Aug 31	08:20:00	10:20:00	7075	1 003	700	2 100	S
Sep 3	17:10:00	17:20:00	7075	1 100	1 500	3 000	S
Oct 27	10:15:00	10:55:00	7075	1 356	100	200	S

NOTE 1—Interruption type S = sustained; M = momentary

NOTE 2—Total customers served = 2 000

The total number of customers who have experienced a sustained interruption is 3 215. The total number of customers experiencing a momentary interruption is 2 400.

Table 5—Extracted customers who were interrupted

Name	Circuit number	Date	Event code	Duration (min)
Willis, J.	7075	Mar 17, 1994	107	8.17
Williams, J.	7075	Apr 15, 1994	256	0.5
Willis, J.	7075	Apr 15, 1994	256	0.5
Wilson, D.	7075	May 5, 1994	435	71.3
Willis, J.	7075	Jun 12, 1994	567	30.3
Willis, J.	7075	Aug 20, 1994	832	267.2
Wilson, D.	7075	Aug 20, 1994	832	267.2
Yattaw, S.	7075	Aug 20, 1994	832	267.2
Willis, J.	7075	Aug 31, 1994	1003	120
Willis, J.	7075	Sep 3, 1994	1100	10
Willis, J.	7075	Oct 27, 1994	1356	40

Table 6—Interruption device operations

Record number	Device	Date	Time	Number of operations	Number of operations to lockout
1	Brk 7075	Apr 15	18:23:56	2	3
2	Recl 7075	Jul 6	09:30:10	3	4
3	Brk 7075	Aug 2	12:29:02	1	3
4	Brk 7075	Aug 2	12:30:50	2	3
5	Recl 7075	Aug 2	13:25:40	2	4
6	Recl 7075	Aug 25	08:00:00	2	4
7	Brk 7075	Sep 2	04:06:53	2	3
8	Recl 7075	Sep 5	11:53:22	3	4
9	Brk 7075	Sep 8	15:25:10	1	3
10	Recl 7075	Oct 2	17:15:19	1	4
11	Recl 7075	Nov 12	00:00:05	1	4

From Table 6, it can be seen that there were eight circuit breaker operations that affected 2 000 customers. Each of them experienced eight momentary interruptions. There were 12 recloser operations that caused 750 customers to experience 12 momentary interruptions. Some of the operations occurred during one reclosing sequence. To calculate the number of momentary interruption events, count only the total number of reclosing sequences. In this case, there were five circuit breaker events (records 1, 3, 4, 7, and 9) that affected 2 000 customers. Each of them experienced five momentary interruption events. There were six recloser events (records 2, 5, 6, 8, 10, and 11) that affected 750 customers, and each of them experienced six momentary interruption events.

4.2 Calculation of indices for a system with no Major Event Days

The equations in 3.5, and definitions in Clause 2, should be used to calculate the annual indices (see Eq. (33) through Eq. (46), below). In the example below, the indices are calculated by using the equations in 3.2 and 3.4 using the data in Table 4 and Table 5, assuming there were no MEDs in this data set.

$$\text{SAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{2000} = 1.61 \quad (33)$$

$$\text{SAIDI} = \frac{(8.17 \times 200) + (71.3 \times 600) + (30.3 \times 25) + (267.2 \times 90) + (120 \times 700) + (10 \times 1500) + (40 \times 100)}{2000} = 86.11 \text{ min} \quad (34)$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{86.110}{1.6075} = 53.57 \text{ min} \quad (35)$$

To calculate CTAIDI and CAIFI, the number of customers experiencing a sustained interruption is required. The total number of customers affected (CN) for this example can be no more than 2 000. Since only a small portion of the customer information table is shown, it is impossible to know CN; however, it is likely that not all of the 2 000 customers on this feeder experienced an interruption during the year. An arbitrary number of customers, 1 800, will be assumed for CN (for your calculations, actual information should be used) since the interruption on September 3 shows that at least 1 500 customers have been interrupted during the year.

$$CTAIDI = \frac{(8.17 \times 200) + (71.3 \times 600) + (30.3 \times 25) + (267.2 \times 90) + (120 \times 700) + (10 \times 1500) + (40 \times 100)}{1800} = 95.68 \text{ min} \quad (36)$$

$$CAIFI = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{1800} = 1.79 \quad (37)$$

$$ASAI = \frac{8760 \times 2000 - (8.17 \times 200 + 600 \times 71.3 + 30.3 \times 25 + 267.2 \times 90 + 120 \times 700 + 10 \times 1500 + 40 \times 100) / 60}{8760 \times 2000} = 0.999836 \quad (38)$$

$$ASIFI = \frac{800 + 1800 + 75 + 500 + 2100 + 3000 + 200}{4000} = 2.12 \quad (39)$$

$$ASIDI = \frac{(800 \times 8.17) + (1800 \times 71.3) + (75 \times 30.3) + (500 \times 267.2) + (2100 \times 700) + 3000(6) + 200 \times 40}{4000} = 444.69 \quad (40)$$

CTAIDI, CAIFI, CEMI_n, CELID-s, CELID-t, and CEMSMI_n require detailed interruption information for each customer. The database should be searched for all customers who have experienced more than n interruptions that last longer than five minutes. Assume n is chosen to be five. In Table 5, customer J. Willis experienced seven interruptions in one year, and it is plausible that other customers also experienced more than five interruptions, both momentary and sustained.

For this example, assume arbitrary values of 350 for $CN_{(k \geq n)}$, 90 for $CN_{(k \geq S)}$, 40 for $CN_{(k \geq T)}$, and 750 for $CNT_{(k \geq n)}$. The number of interrupting device operations is given in Table 6 and is used to calculate MAIFI and MAIFI_E. Assume the number of customers downstream of the recloser equals 750. These numbers would be known in a real system.

$$CEMI_5 = \frac{350}{2000} = 0.175 \quad (41)$$

$$CELID-s(4) = \frac{90}{2000} = 0.045 \quad (42)$$

$$CELID-t(6) = \frac{40}{2000} = 0.02 \quad (43)$$

$$MAIFI = \frac{8 \times 2000 + 12 \times 750}{2000} = 12.5 \quad (44)$$

$$MAIFI_E = \frac{5 \times 2000 + 6 \times 750}{2000} = 7.25 \quad (45)$$

$$CEMSMI_5 = \frac{750}{2000} = 0.375 \quad (46)$$

Using the above sample system should help define the methodology and approach to obtaining data from the information systems and help calculate the indices.

4.3 Examples

This subclause illustrates two concepts—momentary interruptions and step restoration—through the use of examples.

4.3.1 Momentary interruption example

To better illustrate the concepts of momentary interruptions and sustained interruptions and the associated indices, consider Figure 1 and Eq. (45) through Eq. (47). Figure 1 illustrates a circuit composed of a circuit breaker (B), a recloser (R), and a sectionalizer (S).

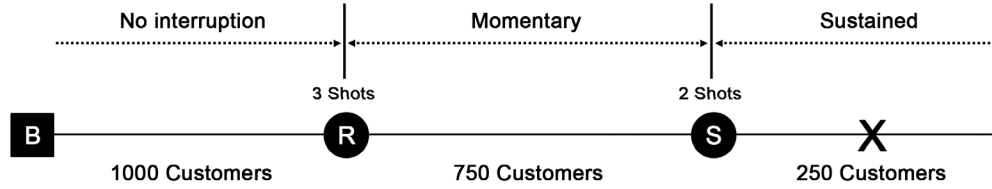


Figure 1—Sample system two

For this scenario, 750 customers would experience a momentary interruption event (two momentary interruptions), and 250 customers would experience a sustained interruption. Calculations for SAIFI, MAIFI, and MAIFI_E on a feeder basis are shown in Eq. (47) through Eq. (49) below. Notice that the numerator of MAIFI is multiplied by two because the recloser took two shots, however, MAIFI_E is multiplied by one because it counts only the fact that a series of momentary events occurred.

$$\text{SAIFI} = \frac{250}{2000} = 0.125 \quad (47)$$

$$\text{MAIFI} = \frac{2 \times 750}{2000} = 0.75 \quad (48)$$

$$\text{MAIFI}_E = \frac{1 \times 750}{2000} = 0.375 \quad (49)$$

4.3.2 Step restoration example

The following case illustrates the step restoration process. A feeder serving 1 000 customers experiences a sustained interruption. Multiple restoration steps are required to restore service to all customers. Table 7 shows the times of each step, a description and associated customers interrupted, and minutes they were affected in a timeline format.

Table 7—Example for a feeder serving 1 000 customers with a sustained interruption

Time from initial fault (min)	Description	Customers remaining interrupted	Customers restored
—	The initial fault occurs, the feeder breaker opens, and all 1 000 customers are interrupted. Switches are opened along the feeder.	1 000	—
45	The feeder breaker is closed, but only 500 customers are restored.	500	500
60	Through closing a switch, an additional 300 customers are restored.	200	800
70	An additional incident occurs which causes the feeder breaker to open, interrupting the 800 customers previously restored.	1 000	—
90	The feeder breaker is closed, and restores 800 customers.	200	800
120	Permanent repairs are completed and the remaining 200 customers are restored. The outage event is concluded.	—	1 000
Totals		N/A	1 800

Figure 2 illustrates the example described in Table 7. Note that both the block of 500 customers and the block of 300 customers experience two interruptions during this event.

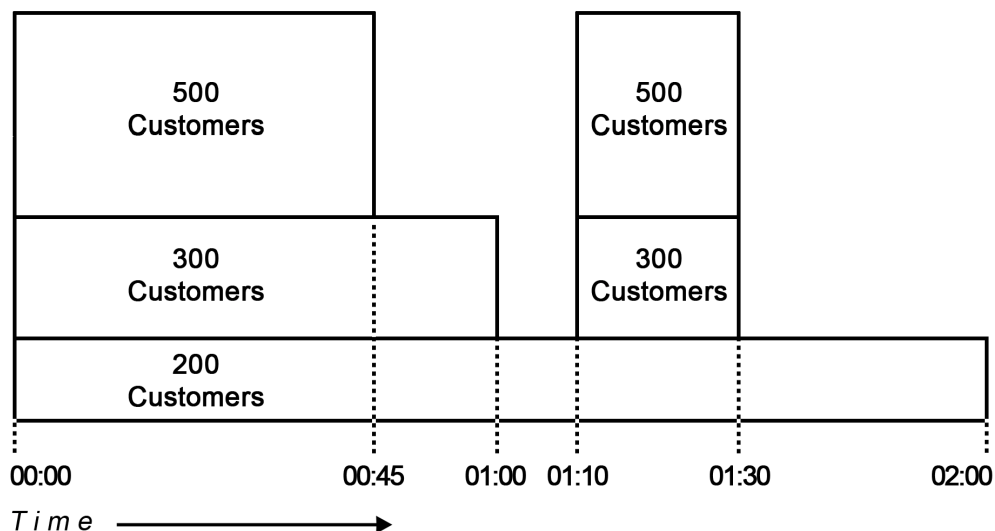


Figure 2—Step restoration time chart

Table 8 enumerates the CI and CMI for the example.

Table 8—Restoration steps for the example

Time	Interruption duration (min)	CI	CMI
00:00-00:45	45	500	22 500
00:00-01:00	60	300	18 000
01:10-01:30	20	800	16 000
00:00-02:00	120	200	24 000
	Total	1 800	80 500

Example SAIFI = $1\,800/1\,000 = 1.8$ interruptions

Example CAIDI = $80\,500/1\,800 = 44.7$ min

Example SAIDI = $80\,500/1\,000 = 80.5$ min

5. Information about the factors that affect the calculation of reliability indices

5.1 Rationale behind selecting the indices provided in this guide

One view of distribution system performance can be garnered through the use of reliability indices. To adequately measure performance, both duration and frequency of customer interruptions must be examined at various system levels. The most commonly used indices are SAIFI, SAIDI, CAIDI, and ASAI, which all provide information about average system performance. Many utilities also calculate indices on a feeder basis to provide more detailed information for decision making. Averages give general performance trends for the utility; however, using averages will lead to loss of detail that could be critical to decision making. For example, using system averages alone will not provide information about the interruption duration experienced by any specific customer. It is difficult for most utilities to provide information on a customer basis. This group believes the tracking of specific details surrounding interruptions, rather than averages, may be accomplished by improving tracking capabilities. To this end, the working group has included not only the most commonly used indices, but also indices that examine performance at the customer level (e.g., CEMI_n and the CELIDs).

5.2 Factors that cause variation in reported indices

Many factors can cause variation in the indices reported by different utilities. Some examples are differences in:

- Level of automated data collection
- Geography
- System design
- Data classification (e.g., Are major events in the data set? Planned interruptions?)

To ensure accurate and equitable assessment and comparison of absolute performance and performance trends over time, it is important to classify performance for each day in the data set to be analyzed as either day-to-day or MED. Not performing this critical step can lead to false decision making because MED performance often overshadows and disguises daily performance. Interruptions that occur as a result of outages on customer-owned facilities, or loss of supply from another utility, should not be included in the index calculation.

5.3 Major Event Days and catastrophic days

When using daily SAIDI and the 2.5β method, there is an assumption that the distribution of the natural log values will most likely resemble a Gaussian distribution, namely a bell-shaped curve. As companies have used this method, a certain number of them have experienced large-scale events (such as hurricanes or ice storms) that result in unusually sizable daily SAIDI values. The events that give rise to these particular days, considered “catastrophic events,” have a low probability of occurring. However, the extremely large daily SAIDI values may tend to skew the distribution of performance toward the right, causing a shift of the average of the data set and an increase in its standard deviation. Large daily SAIDI values caused by catastrophic events will exist in the data set for five years and could cause a relatively minor upward shift in the resulting reliability metric trends. While significant study was undertaken to develop objective methods for identifying and processing catastrophic events (in order to eliminate the noted effect on the reliability trend), the methods that were developed, in order to be universally applied, caused for many

utilities, catastrophic events to occur far too often to accept as being reasonable. In addition, the elimination of catastrophic events from the calculation of the major event threshold caused, in some utilities, a rather large increase of days identified as MEDs in the following five years. It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results.

Annex A

(informative)

Bibliography

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this standard. Reference to these resources is made for informational use only.

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³ IEEE publications are available from The Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (<http://standards.ieee.org/>).

Annex B

(informative)

Major event definition development

B.1 Justification and process for development of the 2.5 β methodology

A statistical approach to identifying MEDs was chosen over the previous definitions because of the difficulties experienced in creating a uniform list of types of major events, and because the measure of impact criterion (i.e., percent of customers affected) required when using event types resulted in non-uniform identification. The statistical methodology should more fairly identify major events for all utilities. Some key issues had to be addressed in order to consider this work successful. These issues include:

- Definition must be understandable and easy to apply.
- Definition must be specific and calculated using the same process for all utilities.
- Must be fair to all utilities regardless of size, geography, or design.
- Entities that adopt the methodology will calculate indices on a normalized basis for trending and reporting. They will further classify the MEDs separately and report on those days through a separate process.

Daily SAIDI values are preferred to daily Customer Minutes of Interruption (CMI) values for MED identification because the former permits comparison and computation among years with different numbers of customers served. Consider the merger of two utilities with the same reliability and the same number of customers. CMI after the merger would double, with no change in reliability, while SAIDI would stay constant.

Daily SAIDI values are preferred to daily SAIFI values because SAIDI values are a better measure of the total cost of reliability events, including utility repair costs and customer losses. The total cost of unreliability would be a better measure of the size of a major event, but collection of this data is not practical.

The selected approach for setting the MED identification threshold, known as the “Two Point Five Beta” (2.5 β) method (since it is using the log-normal SAIDI values rather than the raw SAIDI values), is preferred to using fixed multiples of standard deviation (e.g., “Three Sigma”) to set the identification threshold because the former results in more uniform MED identification among utilities with different sizes and average reliabilities. The β multiplier of 2.5 was chosen because, in theory, it would classify 2.3 days per year as major events. If significantly more days than this are identified, they represent events that have occurred outside the random process that is assumed to control distribution system reliability. The process and the multiplier value were evaluated by a number of utilities with different sized systems from different parts of the United States and found to correlate reasonably well to current major event identification results for those utilities. A number of alternative approaches were considered. None was found to be clearly superior to the 2.5 β method.

When a major event occurs that lasts through midnight (for example, a six hour hurricane which starts at 9:00 p.m.), the reliability impact of the event may be split between two days, neither of which would exceed the T_{MED} and therefore be classified as a MED. This is a known inaccuracy in the method, which is accepted in exchange for the simplicity and ease of calculation of the method. The preferred number of years of data (five) used to calculate the MED identification threshold was set by trading off between the desire to reduce statistical variation in the threshold (for which more data is better) and the desire to see the

effects of changes in reliability practices in the reported results, and to limit the amount of data which must be archived.

B.1.1 Remarks

To generate the example data used in 3.5.1, values of α and β were taken from an actual utility data set, and then daily SAIDI/day values were artificially generated using a log normal distribution with these values of α and β . The daily SAIDI values were then adjusted to illustrate all aspects of the calculation (e.g., a day in Table 2 was assigned a SAIDI value of zero, and a day in Table 3 was assigned a SAIDI value higher than the computed threshold).

This annex provides a technical description and analysis of the 2.5β method of identifying MEDs in distribution reliability data. The 2.5β method is a statistical method based on the theory of probability and statistics. Fundamental concepts such as *probability distribution* and *expected value* are highlighted in italics when they are first used and provided with a short definition. An undergraduate probability and statistics textbook can be consulted for definitions that are more complete.

B.2 2.5β method description

See 3.5 of this guide for the detailed procedure for identifying MEDs. The short version is presented here. A threshold on daily SAIDI is computed once a year as follows:

- a) Assemble the five most recent years of historical values of SAIDI/day. If less than five years of data is available, use as much as is available.
- b) Discard any day in the data set that has a SAIDI/Day of zero.
- c) Find the natural logarithm of each value in the data set.
- d) Compute the average (α , or Alpha) and standard deviation (β or Beta) of the natural logarithms computed in step a).
- e) Compute the threshold $T_{MED} = \exp(\alpha + 2.5 * \beta)$.
- f) Any day in the next year with $SAIDI > T_{MED}$ is a MED.

B.3 Random nature of distribution reliability

The reliability of electric power distribution systems is a *random process*, that is, a process that produces random values of a specific *random variable*. A simple example of a random process is rolling a die. The random variable is the value on the top face of the die after a roll, which can have integer values between one and six.

In electric power distribution system reliability, the random variables are the reliability indices defined in this guide. These are evaluated on a daily or yearly basis and take on values from zero to infinity.

B.4 Choice of SAIDI to identify Major Event Days

Four commonly used reliability indices are:

- a) System Average Interruption Duration Index (SAIDI)
- b) System Average Interruption Frequency Index (SAIFI)

- c) Customer Average Interruption Duration Index (CAIDI)
- d) Average Service Availability Index (ASAI)

These indices are actually measures of unreliability, as they increase when reliability becomes worse.

An ideal measure of unreliability would be customer cost of unreliability—the dollar cost of power outages to a utility’s customers. This cost is a combination of the initial cost of an outage and accumulated costs during the outage. Unfortunately, the customer cost of unreliability has so far proven impossible to estimate accurately. In contrast, the reliability indices above are routinely and accurately computed from historical reliability data. The ability of an index to reflect customer cost of unreliability indicates the best one to use for MED identification.

Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. Thus, a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI. Because CAIDI is a value per customer, it does not reflect the size of outage events. Therefore, SAIDI best reflects the customer cost of unreliability, and is the index used to identify MEDs. SAIDI in minutes/day is the random variable used for MED identification.

The use of CMI per day was also considered. Like SAIDI, CMI is a good representation of customer cost of unreliability. In fact, SAIDI is just CMI divided by the number of customers in the utility. The number of customers can vary from year to year, especially in the case of mergers, and multiple years of data are used to find MEDs. Use of SAIDI accounts for the variation in customer count, while use of CMI does not. Therefore, SAIDI is preferred.

B.5 Probability distribution of distribution system reliability

B.5.1 Probability density functions and probability of exceeding a threshold value

MEDs will be days with larger SAIDI values. This suggests the use of a threshold value for daily SAIDI. The threshold value is called T_{MED} . Days with SAIDI greater than T_{MED} are MEDs. As the threshold increases, there will be fewer days with SAIDI values above the threshold. The relationship between the threshold and the number of days with SAIDI above the threshold is given by the *probability density function* of SAIDI/day.

The probability density function gives the probability that a specific value of a random variable will appear. For example, for a six-sided die, the probability that a one will appear in a given roll is one-sixth, and the value of the probability density function of one is one-sixth for this random process.

The probability that a value greater than one will occur is the sum of the probability densities for all values greater than one. Since each value has a probability density of one-sixth for the example, this sum is simply five-sixths. As the threshold increases, the probability decreases. For example, for a threshold of four, there are only two values greater than four, and the probability of rolling one of them is two-sixths, or one-third.

In the die rolling example, the random variable can have only discrete integer values. SAIDI/day is a continuous variable. In this case, the sum is replaced by an integral. The probability p that any given day will have a SAIDI/day value greater than a threshold value T is the integral of the probability density function from the threshold to infinity as shown in Eq. (B.1):

$$p(\text{SAIDI} > T) = \int_T^{\infty} \text{pdf}(\text{SAIDI}) d\text{SAIDI} \quad (\text{B.1})$$

Graphically, the probability is the area under the probability density function above the threshold, as shown in Figure B.1.

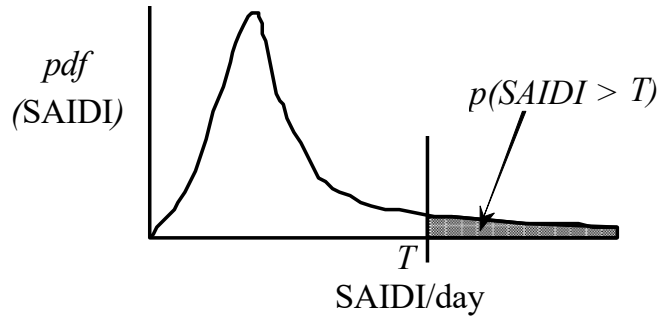


Figure B.1—The area under the probability density of function pdf (SAIDI)

If any given day has a probability p of being a MED, then the *expected value* [see Eq. (B.2)] of the number of MEDs in a year is the probability multiplied by the number of days in a year, as shown in Eq. (B.2):

$$E(MED / year) = 365 \cdot p(SAIDI > T_{MED}) \quad (B.2)$$

For example, if $p = 0.1$, then the expected number of MEDs in a year is 36.5. This does not mean that exactly 36.5 MEDs will occur. The actual number will vary due to the randomness of the process.

Using the die rolling example, the probability of getting a six in any roll is one-sixth. Therefore, the expected number of sixes in six rolls is one. However, if the die is rolled six times, there could be six sixes, or zero sixes, or any number in between. As the number of trials goes up, the number of sixes will approach one-sixth of the number of rolls, but for small numbers of rolls, there will be some variation from the expected value.

B.5.2 Gaussian, or normal, distribution

The expected number of MEDs per year can be computed for any given threshold if the shape of the probability density function is known. The shape of the probability density function is called the *probability distribution*. Specific types of shapes have specific names. The most well known is the *Gaussian distribution*, also called the *normal distribution*, or bell curve, shown in Figure B.2.

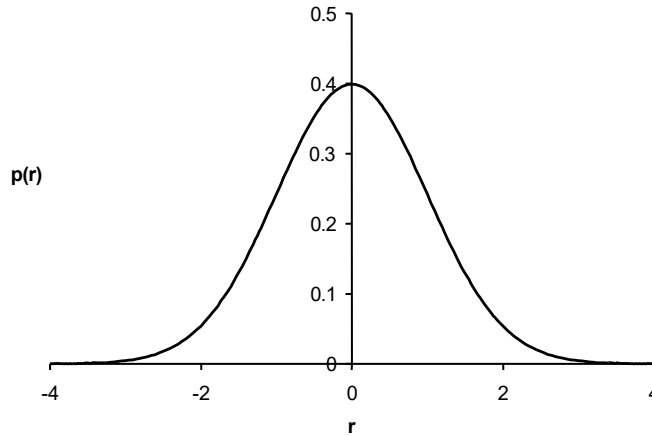


Figure B.2—Gaussian, or normal, probability distribution

The Gaussian distribution is completely described by its *mean*, or average value, (μ or Mu) and its *standard deviation* (σ or Sigma). The average value is at the center of the distribution (at 0 on the x -axis in Figure B.2), and the standard deviation is a measure of the spread of the distribution.

An important property of the Gaussian distribution is that the probability of exceeding a given threshold is a function of the number of standard deviations the threshold is from the mean. Eq. (B.3) expresses this concept in mathematical terms:

$$T_{MED} = \mu + n\sigma \quad (B.3)$$

The threshold is n standard deviations greater than the mean, and the probability of exceeding the threshold, $p(\text{SAIDI} > T_{MED})$, is a function only of n , and not of the mean and standard deviation. Values for this function are found in tables in the backs of probability textbooks and in, for example, standard spreadsheet functions. Table B.1 gives the probability of exceeding the threshold for different number of standard deviations n .

Table B.1—Probability of exceeding a threshold for the Gaussian distribution

n	p
1	0.15866
2	0.02275
3	0.00135
6	9.9×10^{-10}

B.5.3 Three sigma

The term *three sigma* is often used loosely to designate a rare event. It comes from the Gaussian probability distribution. As Table B.1 shows, the probability of exceeding a threshold that is three standard deviations more than the mean is 0.00135, or about one and one-half tenths of one percent. If daily SAIDI had a Gaussian probability distribution, it would be relatively easy to agree on a three sigma definition for the MED threshold, T_{MED} . SAIDI does not have a Gaussian distribution. It has approximately a log-normal distribution.

B.6 Log-normal distribution

The random variable in the Gaussian distribution has a range from $-\infty$ to ∞ . In real life, many quantities, including distribution reliability, can only be zero or positive. This causes the probability distribution to skew, bunching up near the zero value and having a long tail to the right. The degree of skew depends on the ratio of mean to standard deviation. When the standard deviation is small compared to the mean, the log-normal distribution looks like the Gaussian distribution, as shown in Figure B.3(b). When it is large compared to the mean, it does not, as shown in Figure B.3(a). Daily reliability data usually has standard deviation values far larger than the mean.

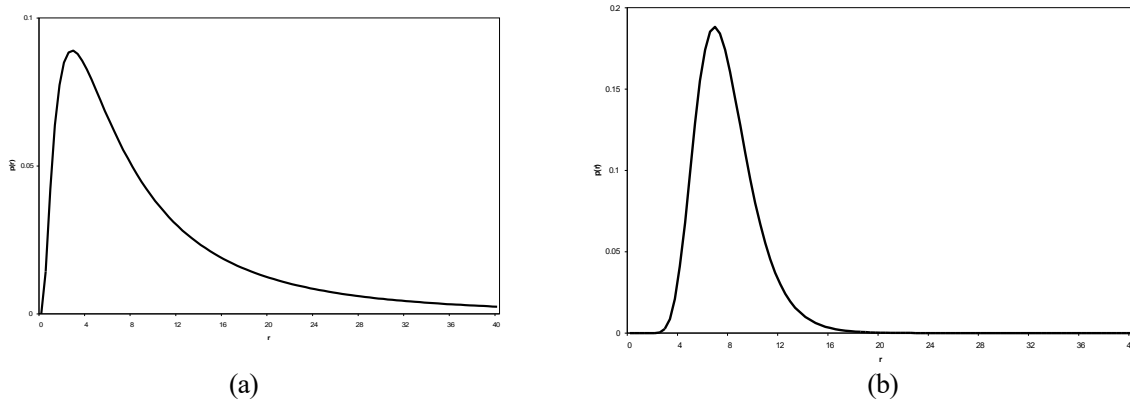


**Figure B.3—Log-normal distributions: (a) Mean less than standard deviation
(b) Mean greater than standard deviation**

The usual way of determining if a set of data has a log-normal probability distribution is to take the natural logarithm of each value in the data set and examine the histogram. If the histogram looks like a Gaussian distribution, then the data has a log-normal distribution. Figure B.4 shows a histogram of the natural logs of daily SAIDI data for an anonymous utility. The histogram is approximately normally distributed, so the data is approximately log-normally distributed. Roughly a dozen utility data sets have been examined, and all are approximately log-normally distributed. No non-log-normally distributed utility data has so far been found. In addition, Monte Carlo simulation models of the distribution reliability process produce log-normally distributed data. Therefore, utility daily reliability is approximately log-normally distributed.

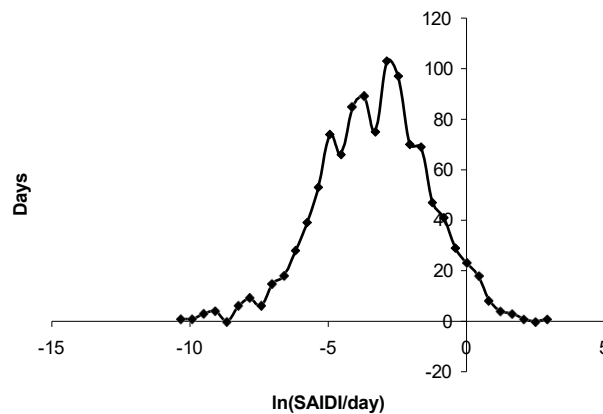


Figure B.4—Histogram of the natural logs of three years of daily SAIDI data from anonymous utility two supplied by the Distribution System Design Working Group

A consequence of the log-normality of daily reliability data is that the three sigma conditions no longer hold. In particular, the probability of exceeding a given threshold is no longer independent of the values of the average and standard deviation of the distribution. This means that using a method such as three sigma would result in significantly different numbers of MEDs for utilities with different average values of reliability, or with different standard deviation values. This seems inequitable.

Fortunately, the logarithms of log-normal data have a Gaussian distribution. If the average of the logarithms of the data is called α , or Alpha, and the standard deviation of the logarithms of the data is called β , or Beta, then α and β are the mean and standard deviation of a Gaussian distribution, and a threshold on the log of the data can be set that is independent of the values of α and β . Eq. (B.4) and Eq. (B.5) show these concepts mathematically.

$$\ln(T_{MED}) = \alpha + k\beta \quad (B.4)$$

$$T_{MED} = \exp(\alpha + k\beta) \quad (B.5)$$

The probability of exceeding T_{MED} is a function of k , just as it was a function of n in the Gaussian example. Table B.2 gives these probabilities as well as the expected number of MEDs for various values of k .

Table B.2—Probability of exceeding T_{MED} as a function of multiples of β

k	p	MEDs/yr
1	0.15866	57.9
2	0.02275	8.3
2.4	0.00822	3.0
2.5	0.00621	2.3
3	0.00135	0.5
6	9.9×10^{-10}	3.6E-07

B.6.1 Why 2.5?

Given an allowed number of MEDs per year, a value for k is easily computed. However, there is no analytical method of choosing an allowed number of MEDs/year. The chosen value of $k = 2.5$ is based on consensus reached among Distribution Reliability Working Group members on the appropriate number of days that should be classified as MEDs. As Table B.2 shows, the expected number of days for $k = 2.5$ is 2.3 MEDs/year. In practice, the experience of the committee members, representing a wide range of distribution utilities, was that more than 2.3 days were usually classified as MEDs, but that the days that were classified as MEDs were generally those that would have been chosen on qualitative grounds. The performance of different values of k were examined, and consensus was reached on $k = 2.5$.

B.7 Fairness of the 2.5β method

It is likely that reliability data from different utilities will be compared by utility management, public utilities commissions, and other interested parties. A fair MED classification method would classify, on average, the same number of MEDs per year for different utilities.

The two basic ways that utilities can differ in reliability terms are in the mean and standard deviation of their reliability data. Differences in means are attributable to differences in the environment between utilities, and differences in operating and maintenance practices. Differences in standard deviation are mostly attributable to size. Larger utilities have inherently smaller standard deviations.

As discussed above, using the mean and standard deviation of the logs of the data (α and β) to set the threshold makes the expected number of MEDs depend only on the multiplier and thus should classify the same number of MEDs for large and small utilities, and for utilities with low and high average reliability.

This is not the case for using the mean and standard deviation of the data without taking logarithms first. The expected number of MEDs varies with the mean and standard deviation. This variation occurs because of the log-normal nature of the reliability probability distribution.

Experience with the 2.5β method has shown that it is better than using mean and standard deviation, but it is not perfect. The number of MEDs identified per year is significantly higher than expected, and the average number of MEDs varies somewhat from utility to utility, with size affecting the value. These effects appear because the probability distribution of distribution system reliability is only approximately log-normal. Significant differences appear in the right hand tail of the distribution, which in general contains more probability than a perfect log-normal distribution. This “fat tail” effect accounts for the larger-than-predicted number of identified MEDs. The effect of utility size is less clearly understood.

Despite these issues, the 2.5β method of MED identification is much closer to the ideal fair process than using a Gaussian distribution, using the heuristic definitions that preceded it, or any other method proposed to date. It has been carefully tested and has been broadly accepted by the utilities in the Distribution Design Working Group and many other utilities and regulators that have adopted this guide.

B.8 Five years of data

From a statistical point of view, the more data used to calculate a threshold, the better. However, the random process producing the data changes over time as the distribution system is expanded and operating procedures are varied. Using too much historical data would suppress the effects of these changes.

The addition of another year of data should have a low probability of changing the MED classification of previous years. A result from order statistics gives the probability that the k th largest value in m samples will be exceeded f times in n future samples. It is given in Eq. (B.6):

$$P_{f|m,k,n} = \frac{k}{n+k-f} \frac{\binom{m}{k} \binom{n}{f}}{\binom{n+m}{n+k-f}} \quad (\text{B.6})$$

For example, if $M = 3$ years of data, then $m = 1\,095$ samples. If $f = 3$ MEDs/year, then the largest non-MED is the $k = 1\,095 - 9 = 1\,086^{\text{th}}$ ordered sample. The probability of $f = 3$ days in the next year of $n = 365$ samples exceeding the size of the largest non-MED is found from the equation to be 0.194 (19.4%). In Figure B.5, p is plotted against M for several values of f .

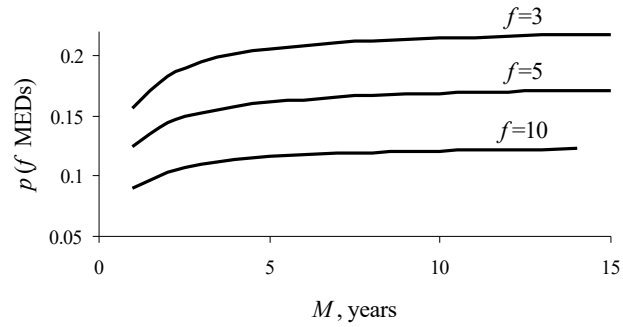


Figure B.5—Probability of exactly f new MEDs in the next year of data using M years of historical data

The consensus of the Design Working Group members was that five years was the appropriate amount of data to collect. The group felt that the distribution system would change enough to invalidate any extra accuracy from more than five years of data.

Annex C

(informative)

Internal data subset

C.1 Calculation of reliability indices for subsets of data for internal company use

Reliability performance can be assessed for different purposes. It may be advantageous to calculate reliability indices without planned interruptions in order to review performance during unplanned events. In another case, it may be advantageous to review only sustained interruptions. Assessment of performance trends and goal setting should be based on normal event days (neglecting the impact of MEDs). Utilities and regulators determine the most appropriate data to use for reliability performance monitoring. When indices are calculated using partial data sets, the basis should be clearly defined for the users of the indices. At a minimum, reliability indices based on all collected data for a reporting period and analyzed as to normal versus MED classifications should be provided. Indices based on subsets of collected data may be provided as specific needs dictate.

Appendix D

NERC TADS

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Availability Data System

Data Reporting Instructions

Effective: January 2024

RELIABILITY | RESILIENCE | SECURITY



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Table of Contents

Preface	iv
Introduction	v
Background.....	v
Who Must Report	v
What Will Be Reported.....	v
Chapter 1: Data Transmittal and Format	1
OATI and webTADS.....	1
Transmitting TADS Data Securely by E-mail	1
Data Confidentiality.....	1
Chapter 2: Data Collection Forms	3
Multiple-Owner Element Forms.....	4
Form 2.1: Multiple-Owner AC and DC Circuits	4
Form 2.2: Multiple-Owner AC/DC Back-to-Back Converter.....	6
Chapter 3: Element Inventory Data Forms	7
Form 3.1: AC and DC Inventory Data	7
Form 3.2: Transformer Detailed Inventory Data	10
Form 3.3: AC/DC BTB Converter Inventory Data	10
Form 3.5: AC Multi-Circuit Structure Miles	11
Form 3.6: Common Corridors	12
Chapter 4: Detailed Automatic Forms	13
Forms 4.1-4.4: Detailed Automatic Outage	13
Chapter 5: TADS Event Forms	15
Form 5.0: Event ID Codes.....	15
NERC Multiple Utility Event ID Code Creation.....	16
Cascading Tolerance	16
Event Type Numbers.....	16
Non-TADS Element Outages	17
Event Type Number 13 versus Event Type Number 11	17
Event Description.....	17
Event Analysis Guidelines	18
Event Type Number Determination.....	18
Example of an Event with Normal Clearing	18
Example of an Event with Normal Clearing beyond the NCCBS	18

Examples of an Event Type Number 49:.....	19
Example of an Event Type Number 90	20
Chapter 6: Detailed Non-Automatic Outage Data	21
Forms 6.1-6.4	21
Outages That Continue Beyond the End of the Year	21
Long Duration Outages	22
Appendix A: Definitions.....	23
Appendix B: Inventory Data Calculation and Entry.....	44
Appendix C: Detailed Automatic Outage Data Examples	48
Appendix D: Frequently Asked Questions.....	68
Appendix E: Metrics	82
Appendix F: Revision History.....	83

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Introduction

Background

Transmission Availability Data Systems (TADS) Data Reporting Instructions (DRI) were developed to assist TO personnel in reporting information to NERC's TADS reporting application. These instructions detail the procedures, schedule, and format to follow when reporting data.

Who Must Report

Reporting of transmission performance and inventory data is mandatory for all NERC registered TOs. TADS outage data is due 45 days after the end of each calendar quarter.

The following describe reporting requirements for different TO situations:

1. TOs that do not own any TADS Elements are not required to submit any other TADS data for the reporting calendar year even if they subsequently become owners of TADS Elements during that calendar year. However, a TO may voluntarily report data for the year that the TADS Elements are added.
2. A non-reporting TO that becomes unregistered during a calendar year is no longer subject to any TADS reporting requirements. However, if a reporting TO becomes unregistered during a reporting calendar year, it has either (i) retired all its TADS Elements or (ii) sold all its TADS Elements. In case (ii), the new TO shall assume the reporting obligation of the unregistered TO for the entire calendar year. This will ensure that all TADS Elements continue to have their data reported.

What Will Be Reported

Inventory and performance data will be collected for all Bulk Electric System (BES) Elements which fall into one of the four categories below:

1. AC Circuits (Overhead and Underground)
2. Transformers with ≥ 100 kV secondary voltage
3. AC/DC Back-to-Back Converters
4. DC Circuits (Overhead and Underground)

Table I.1 lists the type of outages which are collected by voltage class.

Table I.1: TADS Outage Collection by Voltage Class				
Voltage Class	Automatic Outages		Non-automatic Outages	
	Sustained	Momentary	Planned	Operational
0-199 kV	Yes	No	No	No
200 kV and Above	Yes	Yes	No	Yes

The Outage Reporting Reference Guide located in **Figure I.1** below can be used to determine whether and Element outage is TADS-reportable.

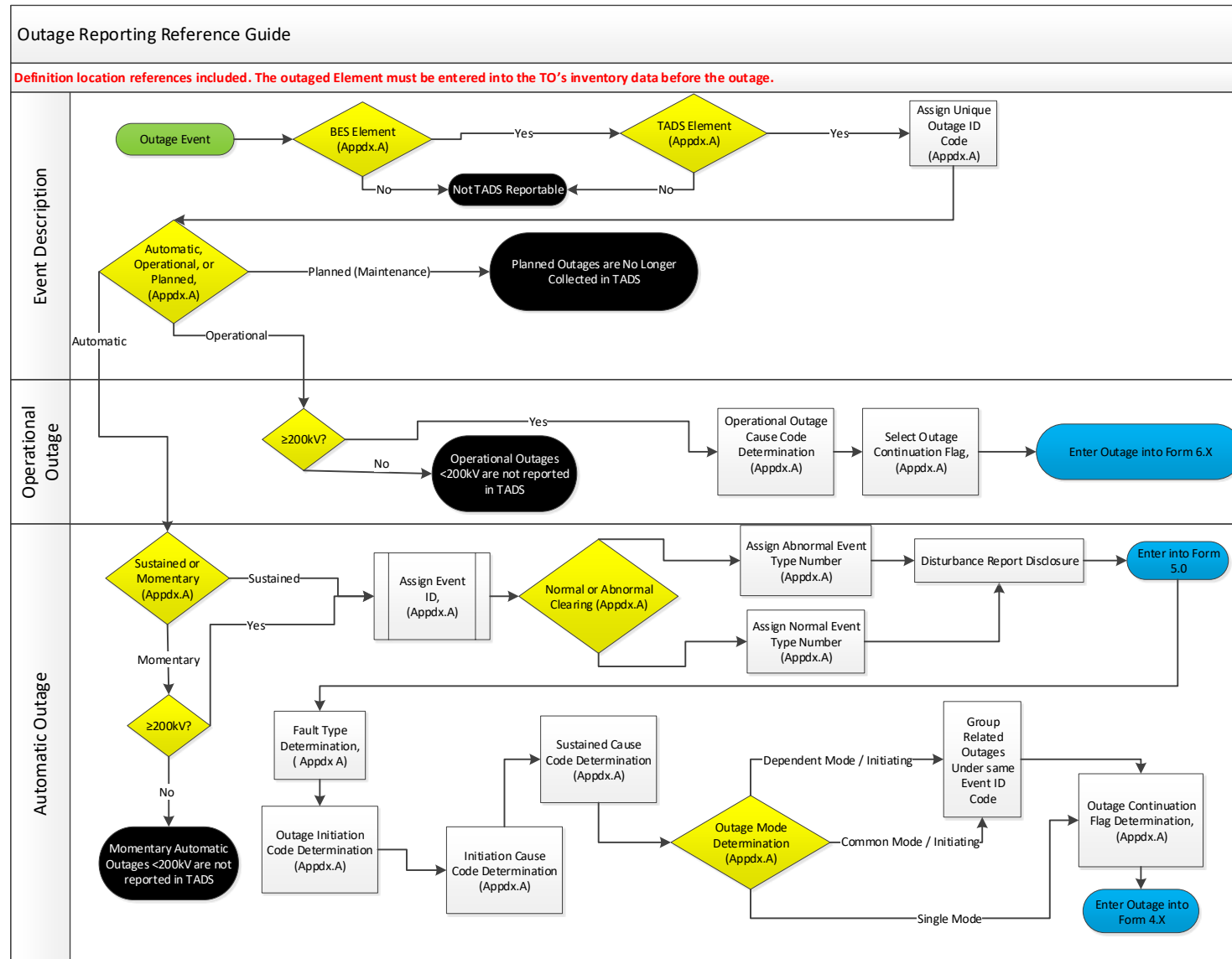


Figure I.1: Outage Reporting Reference Guide

Chapter 1: Data Transmittal and Format

OATI and webTADS

NERC contracted with Open Access Technology International, Inc. (OATI) to develop a software data system named “webTADS” to support several processes, including:

- Data entry
- Data error checking
- Data management
- Data analysis and reporting

The webTADS system allows TOs to directly enter their data or have it bulk-uploaded from XML files, which are created from the data entered into the TADS Reporting Workbook posted on the TADS website.¹ Each version of the workbook is assigned a number, and TOs should use the latest version of the workbook to ensure their data will be accepted by webTADS.

Regional Entities are the point of contact for TADS data submittals, and they prescribe and supervise the data entry process for TOs within their Region.

1. All Regions require TOs to input data directly into webTADS. Through webTADS, Regional Entities will have access to the data for TOs within their Region so that they can review that data.
2. WECC is collecting additional data beyond that required by TADS. For convenience, this data can be entered into webTADS and is considered voluntary.

Transmitting TADS Data Securely by E-mail

E-mail is primarily used by TOs to transmit corrections to data that must be entered by a Regional Entity coordinator or NERC staff when webTADS data entry is closed to TOs. If an entity (TO, Regional Entity, or NERC) has its own critical infrastructure protection (CIP) procedure for transmitting confidential information by e-mail, that procedure should be followed. If those procedures are not yet developed, the following process should be followed:

1. Password-protect the document to be transmitted and send it via e-mail to the recipient. Do not include the password in this e-mail.
2. In a second separate e-mail, send the password to the recipient of the document.

Data Confidentiality

Under NERC’s confidentiality policy (Section 1500 of NERC’s Rules of Procedures)², the entity claiming that information is confidential must state the category under which such information qualifies as confidential.

For practicality, certain data has been judged as confidential because it contains critical energy infrastructure information (CEII) while other information is not confidential. A list of the data considered confidential can be found in the TADS Reporting Workbook under the tab labeled “Form 1.2 TO Info”. A TO may change NERC’s default confidentiality classification by sending an e-mail to the NERC project manager – see the TADS Program Contact’s information on the TADS website.

¹ <https://www.nerc.com/pa/RAPA/tads/Pages/default.aspx>

² https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20190125.pdf

If a TO wants non-confidential data to be made confidential, the TO must indicate the category or categories defined in Section 1501 in which the data falls. See Section 1502 of the *Rules of Procedure*.

CEII is defined by Federal Energy Regulatory Commission (FERC) rules as follows:³

1. Critical energy infrastructure information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
 - a. Relates details about the production, generation, transportation, transmission, or distribution of energy;
 - b. Could be useful to a person in planning an attack on critical infrastructure;
 - c. Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
 - d. Does not simply give the general location of the critical infrastructure.
2. Critical infrastructure means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

Regional and NERC annual public performance reports will show aggregated confidential information of many TOs. In doing so, no particular TOs data should be identifiable. However, these reports will not inadvertently release confidential information by the display of Regional or NERC information from which a TOs confidential information could be ascertained. For example, if the TO in a Region is the only owner of assets at a particular voltage, the metrics on that data would not be released if the TOs name and its confidential information could be identified, unless the TO agrees to such a release. If a particular TOs metrics could be identified in a report, the TO will be asked to voluntarily allow reporting of its metrics while keeping other aspects of its data confidential. By “other aspects of its data”, other TADS data, such the date of an outage or the substations that identify the circuit outage, are meant. Those inputs allow an RE or NERC to determine whether outages of different TOs are a single Event. These requests will be addressed on a case-by-case basis.

³ <https://www.ferc.gov/legal/ceii-foia/ceii.asp>

Chapter 2: Data Collection Forms

Information collected in webTADS is organized by data forms, one for each type of data being entered. Each of the tabs in the TADS Reporting Workbook corresponds to one of these data forms. The 18 forms are listed below in [Table 2.1](#) and written instructions for completing each form is contained in this chapter.

When a TADS-reportable outage occurs:

1. The outaged Element should first be entered into the TO's inventory data using forms 3.1 - 3.6
2. Next an event record is created using form 5.0
3. Finally, the outage information is entered using forms 4.1 - 4.4 or 6.1 - 6.1.

Table 2.1: TADS Data Forms	
Form	Title
1.1	Non-Reporting Transmission Owner Statement
1.2	Reporting Transmission Owner Information
2.1	Multiple-Owner AC and DC Circuits
2.2	Multiple-Owner AC/DC Back-to-Back Converters
3.1	AC and DC Circuit Detailed Inventory Data
3.2	Transformer Detailed Inventory Data
3.3	AC/DC Back-to-Back Converter Detailed Inventory Data
3.5	AC Multi-Circuit Structure Miles
3.6	Common Corridors (WECC TOs Only; Voluntary)
4.1	AC Circuit Detailed Automatic Outage Data
4.2	DC Circuit Detailed Automatic Outage Data
4.3	Transformer Detailed Automatic Outage Data
4.4	AC/DC Back-to-Back Converter Detailed Automatic Outage Data
5.0	ID Code and Event Type Number Data
6.1	AC Circuit Detailed Non-Automatic Outage Data
6.2	DC Circuit Detailed Non-Automatic Outage Data
6.3	Transformer Detailed Non-Automatic Outage Data
6.4	AC/DC Back-to-Back Converter Detailed Non-Automatic Outage Data

Each data form has a common layout:

1. A TO who does not own any TADS Elements is referred to as a "non-reporting TO." Those TOs must submit Form 1.1 to the RE. A TO owning TADS Elements is referred to as a "reporting TO." On Form 1.2, which is required for a reporting TO, one portion requests the TOs name, its NERC ID number, the name of its RE, its country, and the reporting calendar year. This information is input once on Form 1.2 and linked to subsequent forms. If a TO owns TADS Elements in different Regions and/or different countries, it must complete separate TADS submittals to for each Region and country.
2. The column letters and sometimes the row numbers for each form are used as references in the instructions. TOs may add additional rows as needed. Many columns have drop-down menus that correspond to defined choices. For example, all Cause Codes are in a drop-down menu and provide the TO the choice among the *defined* Cause Codes only.
3. To keep the form format and column letter designation the same within a form type, the unused columns are hidden from view. Therefore, column letter designations will not be in sequence when a column has been hidden.

Appendix C contains examples to assist the TO in *completing* Forms 3.1-3.5, which contain detailed Element inventory data. Form 3.6 is voluntary for all TOs and only applies to WECC TOs. **Appendix D** contains examples to assist the TO in completing Forms 4.1-4.4, which contain detailed Element Automatic Outage data.

Multiple-Owner Element Forms

These forms are used to ensure that only one TO takes on the TADS reporting responsibility for multiple-owner Elements for all Automatic and Non-Automatic outages. However, if a TO has less than 100% ownership interest in such Elements, each TO must enter this Element on Form 2.1 or 2.2. These multiple entries should be coordinated by the TOs involved. This list of such Elements should also include any multiple-owner Element that was in-service for at least part of the reporting period.

Each such Element and its associated multiple-owner Element Identifier (Column I below) should be listed on Form 2.x. The coordinated entries should indicate which single TO will take reporting responsibility for Forms 3, 4, 5 and 6. The single TO designated as the Reporting TO (Column G-H below) must include that Element within their detailed inventory on the appropriate Form 3.x. The same Reporting TO must enter the Element's outages on their Form 4 and 6. The calculated metrics are based on the reported inventory and outages. Selecting a single TO to become the Reporting TO for these inventory and outage forms will avoid duplication of outage and inventory reporting. The other TOs who are multiple owners must be aware that they should not report to TADS on that Element. In addition to the names of all multiple owners, their registered NERC ID (or NERC assigned pseudo ID) of the designated reporting representative is also required to be entered on Form 2.x.

If a TO owns 100% of an Element, the reporting responsibility of that Element belongs to the TO. Do not enter the Element on Forms 2.1 or 2.2. For 100% owned ac circuits, communication among the TOs who own the ac substations that bound the circuit is expected for the purpose of identifying data related to the cause of the outages which the reporting TO must supply.

Forms 2.x are submitted twice for each reporting year:

1. In December of the year prior to the reporting calendar year.
2. During Quarter 4 data reporting and the detailed inventory update.

The first Form 2.x submission in December confirms who is the reporting TO. The reporting TO should internally collect the multiple owner outage information starting on January 1. WebTADS official data entry may occur later in the year. However, the multiple owner outage information should be collected by the designated reporting TO starting January 1. The second submission reflects any additions or retirements of Elements that are covered by these forms.

Among all of the owners for a particular Element, they must agree on the Element ID to be entered in Column I. Only the TO declared to be the reporting TO on Form 2.x can use that Element ID. If one of the non-reporting TO owners also enters that Element ID for an Outage, the Outage will be rejected as an error when they complete Form 4.x or Form 6.x. Therefore, Form 2.x must be marked as complete prior to final completion of Form 4.x and Form 6.x. When Form 4.x and Form 6.x are marked complete, software error checks are performed on each outage to confirm that the declared Element ID on Form 2.x has not been used by one of the wrong multiple owners, declared on Form 2.x.

Form 2.1: Multiple-Owner AC and DC Circuits

The characteristics of each multiple-owner circuit are input on this form (one circuit per row). TOs must mutually agree on who should report outage and inventory information (on Forms 3, 4, 5 and 6) of the multiple-owner circuit information for TADS and which other owners should not report. Do not enter circuits that you do not partially own.

For Multiple-Owner AC and DC Circuits form fields. See [Table 2.2](#).

Table 2.2: Multiple-Owner AC and DC Circuits Form Fields

Column	Form 2.1 Descriptor
None	Questions 1 and 2 in the top of the form ask whether there were any additions of multiple-owner circuits during the reporting year and if so, whether those changes were incorporated into the response. These questions apply to the second submittal only, and appropriate “NA” responses are provided as an answer associated with a first submittal.
A	The type of circuit (AC or DC), input from a drop-down menu, describes the main characteristic of the Element.
B	From – Substation or Terminal Name. The alphanumeric code designating one of the Substation Names for an AC Circuit or one of the Terminal Names for a DC Circuit. If the Element has more than 3 Terminals, only list the first 3 Terminals.
C	To – Substation or Terminal Name. The alphanumeric code designating a second Substation Name for an AC Circuit or a second Terminal Name for a DC Circuit.
D	To2 – Substation or Terminal Name. The alphanumeric code designating a third Substation Name for an AC Circuit or a third Terminal Name for a DC Circuit.
E	The Voltage Class of the Element, input from a drop-down menu. The 400-599 kV Voltage Class can only be used if “AC” is selected in column A, and the 400-499 kV and 500-599 kV Voltage Classes can only be selected if “DC” is selected in column A. Other Voltages Classes (200-299 kV and 600-799 kV) can be used for either AC or DC Circuits. Data that does not conform to this requirement will be rejected and an error notice provided.
F	Underground or Overhead. This Element characteristic is input from a drop-down menu. See the definition of Overhead and Underground in Appendix A .
G-H	The NERC ID number and name of the TO with TADS outage reporting responsibility for the multiple-owner circuit.
I	The reporting TOs Element Identifier. This is a required data entry. The multiple owners of this Element shall also use the same Element Identifier on their Form 2.x for this Element. However, only one TO can be designated as the reporting TO for a given set of multiple-owners using the given Element ID. Only the Reporting TO should enter the Element Identifier of Multiple-Owner Elements on their Series 3 forms.
J-AD	The NERC ID numbers and name of the TOs that have an ownership interest in the Element. Up to ten owner names are provided. One of the TOs must be the TO with TADS reporting responsibility input in columns G-H. Among the multiple-owners, only the reporting TO can input the above Column I Element ID for reported outages on their Form 4.x and Form 6.x. The other multiple owners are not permitted to use the above Column I Element ID for outages reported on their Forms 4.x or Form 6.x.

Form 2.2: Multiple-Owner AC/DC Back-to-Back Converter

The characteristics of each multiple-owner AC/DC Back-to-Back Converter are input on this form (one Element per row). This form is *not* to be used for AC/DC Back-to-Back Converters owned 100% by a single TO.

Table 2.3: Multiple-Owner AC/DC Back-to-Back Converters

Column	Form 2.2 Descriptor
None	Questions 1 and 2 in the top of the form ask whether there were any additions of multiple-owner AC/DC BTB Converters during the reporting year and if so, whether those changes were incorporated into the response. These questions apply to the second submittal only, and appropriate “NA” responses are provided as an answer associated with a first submittal.
A	Converter Station Name. The alphanumeric code designating the converters name.
B	Reporting TOs NERC ID.
C	Reporting TOs Name.
D	The reporting TOs Element Identifier. This is a required data entry. The multiple owners of this Element shall also use the same Element Identifier on their Form 2.x for this Element. However, only one TO can be designated as the reporting TO for a given set of multiple-owners using the given Element ID. Only the reporting TO should enter the Element Identifier of Multiple-Owner Elements on their Series 3 forms.
E	The AC Circuit Voltage Class, input from a drop-down menu, on one side of the converter.
F	The AC Circuit Voltage Class, input from a drop-down menu, on the other side of the converter.
G-AE	The NERC ID numbers and names of the TOs that are multiple owners of the Element. Up to four owner names are provided. One of the TOs must be the TO with TADS reporting responsibility input in column G-H.

Chapter 3: Element Inventory Data Forms

Inventory data for each Entity is carried over from year to year and acts as a living snapshot of an Entity's system in the field. This data is updated on a quarterly basis to account for system reconfigurations, retirements, and new Elements being placed in service. When entering an outage into webTADS, the first step is to enter the outaged Element into the TADS inventory data. If the Element already exists in TADS, then the user can then proceed to complete the Event and Outage data forms.

Form 3.1: AC and DC Inventory Data

Table 3.1 records the detailed inventory details for AC and DC Circuit Elements.

Table 3.1: AC Circuit and DC Circuit Detail Inventory Form (* Indicates Mandatory Fields)		
Column	Form 3.1 Field Name	Form 3.1 Descriptor
A	Unique Element Identifier*	A TO defined unique Element Identifier. Element Identifiers cannot be reused in any future reporting period for a different Element. If there are multiple owners of the Element, those TOs must agree on the Element Identifier.
B	Voltage Class*	The Element's Voltage Class: AC Circuit= phase-to-phase DC Circuit= phase-to-return The 400-599 kV Voltage Class can only be used if "AC" is selected in column C, and the 400-499 kV and 500-599 kV Voltage Classes can only be selected if "DC" is selected in column C. Data that does not conform to this requirement will be rejected and an error notice provided.
C	Circuit Type*	ACO = Overhead AC Circuit Element ACC = Underground AC Circuit Element DCO = Overhead DC Circuit Element DCC = Underground DC Circuit Element
D-F	From Bus, To Bus, and Tertiary Bus*	Data that provides a description of the physical location of the Element terminals. Terminals are those buses on the Element, behind which exist power sources. In general, these terminals will comprise the set of locations that need to open to clear faults on the Element. Buses connected to the Element that serve only load, without power sources available behind them are not considered terminals. AC Circuit = AC Substation Names (3 max)
G	Circuit Miles*	The Circuit Mileage of the Element. For TADS purposes, a DC Circuit is assumed to have 2 poles. For example, a one mile-long, DC tower line that carries two DC poles would equate to two Circuit Miles.
H	Number of Terminals*	The number of terminals that the Element connects to.

Table 3.1: AC Circuit and DC Circuit Detail Inventory Form
 (* Indicates Mandatory Fields)

Column	Form 3.1 Field Name	Form 3.1 Descriptor
I	Conductors per Phase	The number of conductors on the Element per Phase.
J	Overhead Ground Wire	The number of overhead ground wires on the Element.
K	Insulator Type	The type of insulator used on at least 80% of the Element. If multiple types are used such that at least 80% of the Element does not comprise one type, selected "Mixed". CEP = Ceramic Post CES = Ceramic Suspension POP = Polymer Post POS = Polymer Suspension GLS = Glass Suspension MXD = Mixed OTH = Other
L	Cable Type	The type of cable used on the Element. SWD = Solid with conduit SND = Solid with no conduit OWD = Oil filled with conduit OND = Oil filled with no conduit GWD = Gas filled with conduit GND = Gas filled with no conduit.
M	Structure Materials	The type of structure materials used on at least 80% of the Element. If multiple types are used such that at least 80% of the Element does not comprise one type, selected "Mixed". AL = Aluminum CN = concrete FG = fiberglass ST = steel WD = wood CM = composite OT = other MX = mixed.
N	Structure Types	The type of structure materials used on at least 80% of the Element. If multiple types are used such that at least 80% of the Element does not comprise one type, selected "Mixed". DLC = Double Lattice Column HFR = H Frame KFR = K Frame LAT = Lattice Tower SPG = Single Pole Guyed SPU = Single Pole Un-guyed

Table 3.1: AC Circuit and DC Circuit Detail Inventory Form
(* Indicates Mandatory Fields)

Column	Form 3.1 Field Name	Form 3.1 Descriptor
		DOP = Double Pole SLC = Single Lattice Column YTY = Y Type OTH = Other MXD = Mixed
O	Circuits per Structure	The number of circuits per structure on the Element.
P	Terrain	The type of structure materials used on at least 80% of the Element. If multiple types are used such that at least 80% of the Element does not comprise one type, selected "Mixed". If multiple types are applicable, pick the type the most influences outages. CO = Coastal DS = Desert MT = Mountains FR = Forest UR = Urban PR = Prairie MX = Mixed
Q	Elevation	Enter the range of elevation that the circuit traverses. 1 = less than 2000 feet 2 = 2001 to 4000 feet 3 = 4001 to 6000 feet. 4 = 6001 to 8000 feet 5 = 8001 to 10000 feet 6 = 10001 to 12000 feet 99 = elevation varies more than 2000 feet
R	Change/Reconfiguration Date*	Enter the date (mm/dd/yyyy) that the Element last changed or the initial in-service date.
S	Retirement Date*	If applicable to the Element, the date the Element became out-of-service.
T	Precursor Element Identifier*	The Unique Element Identifier that precedes the Element. This is used to maintain a parent/child relationship as Elements are modified.
U	BES Exempted Flag*	If the Element was reported in a prior reporting year and is now no longer considered within the BES, this flag should be TRUE. Also, the retirement date should be set to the date that the Element was Exempted from the BES.

Form 3.2: Transformer Detailed Inventory Data

Table 3. records the detailed inventory details for Transformer Elements. The inventory details should be updated with the fourth quarter reporting. If entering an outage on a circuit not in the inventory detail, the identifier should be entered to allow validation of the Element.

Table 3.2: Transformer Detail Inventory Form (* Indicates Mandatory Fields)		
Column	Form 3.2 Field Name	Form 3.2 Descriptor
A	Unique Element Identifier*	A TO defined unique Element Identifier. Element Identifiers cannot be reused in any future reporting period for a different Element. If there are multiple owners of the Element, those TOs must agree on the Element Identifier.
B	Located at (AC Substation Name)*	The substation name where the transformer is located.
C	High-Side Voltage Class*	The Transformer Primary-Side's Voltage Class.
D	Low-Side Voltage Class*	The Transformer Secondary's Voltage Class
E	Phasing	The phasing of the Transformer. Single = Composed of a single 3-Phase bank transformer Single Phase of 3-Phase Bank = Composed of 3 single phase transformers
F	Three Phase Rating	The rating, in MVA, of the Transformer (all 3-phases combined).
G	Change/Reconfiguration Date*	Enter the date (mm/dd/yyyy) that the Element last changed or the initial in-service date. For transformers in general, the initial transformer in-service date would be used. If the change involves replacing the transformer with a new transformer (or transformers), then that would constitute a new Element.
H	Retirement Date*	If applicable to the Element, the date the Element became out-of-service.
I	Precursor Element Identifier*	The Unique Element Identifier that precedes the Element. This is used to maintain a parent/child relationship as Elements are modified.
J	BES Exempted Flag*	If the Element was reported in a prior reporting year and is now no longer considered within the BES, this flag should be TRUE. Also, the retirement date should be set to the date that the Element was Exempted from the BES.

Form 3.3: AC/DC BTB Converter Inventory Data

Table 3. records the detailed inventory details for AC/DC Back-to-Back Converter Elements. The inventory details should be updated with the fourth quarter reporting. If entering an outage on a circuit not in the inventory detail, the identifier should be entered to allow validation of the Element.

Table 3.3: AC/DC Back to Back Converter Detail Inventory Form
 (* Indicates Mandatory Fields)

Column	Form 3.3 Field Name	Form 3.3 Descriptor
A	Unique Element Identifier*	A TO defined unique Element Identifier. Element Identifiers cannot be reused in any future reporting period for a different Element. If there are multiple owners of the Element, those TOs must agree on the Element Identifier.
B	Converter Name*	The substation name where the AC/DC BTB Converter is located.
C	Voltage Class*	The AC/DC BTB Converter's Voltage Class.
D	Change/Reconfiguration Date*	Is when the element was placed in-service. If this is unknown, use the January 1 of the current year you are reporting. If the element is altered/reconfigured in a way that would change its rating or voltage characteristics, then that date would be entered here.
E	Retirement Date*	If applicable to the Element, the date the Element became out-of-service.
F	Precursor Element Identifier*	The Unique Element Identifier that precedes the Element. This is used to maintain a parent/child relationship as Elements are modified.
G	BES Exempted Flag*	If the Element was reported in a prior reporting year and is now no longer considered within the BES, this flag should be TRUE. Also, the retirement date should be set to the date that the Element was Exempted from the BES.

Form 3.5: AC Multi-Circuit Structure Miles

For TOs located outside of WECC: In contrast to the detailed inventory in Forms 3.1, 3.2 and 3.3, AC Multi-Circuit Structure Miles are collected on a summary basis.

For TOs located inside of WECC: Form 3.5 is a summary form that uses Form 3.6 Common Corridors to populate the data. Please fill out Form 3.6, and this form will auto-populate.

For TOs outside of WECC: Form 3.5 should be completed and should not fill out the Form 3.6 Common Corridors form.

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

All DC Circuits are assumed to have two circuits per structure; therefore, for each DC Circuit Voltage Class, the Multi-Circuit Structure Miles is one-half of the total Circuit Miles.

Table 3.5⁴: AC Multi-Circuit Structure Miles

Column	Form 3.5 Descriptor
None	Questions 1 and 2 ask whether the coordination requested below for AC Multi-Circuit Structure Miles Inventory Data has taken place among TOs that report separate circuits on common structures.
	AC Multi-Circuit Structure Miles Inventory Data

⁴ Table 3.4 excluded to better align with TADS form numbers.

Table 3.5⁴: AC Multi-Circuit Structure Miles

Column	Form 3.5 Descriptor
	Appendix 8 has an example that illustrates the data requirements for columns B-K for Multi-Circuit Structure Miles. - Note: Multi-circuit structures that are occupied by <i>only one circuit</i> do not contribute to the tabulation of Multi-Circuit Structure Miles. Appendix D illustrates how to make this calculation for an annual submittal. For common structures that carry circuits owned by different TOs, TOs are expected to coordinate with one another on their reporting of Multi-Circuit Structure Miles to ensure no double counting occurs. As an example, suppose two circuits owned by different TOs occupy common structures for 10 miles. For this section, the combined number of Multi-Circuit Structure Miles reported by the TOs should not exceed 10. We do not want each TO to report 10 miles since that would double count the miles for the Region.
A	AC multi-circuit structure Voltage Class. Note the “Mixed Voltage” class. This class applies to multi-circuit structures that have two TADS AC Circuits of different voltages (e.g., 230 kV and 345 kV) on the same structure. A structure is not considered a multi-circuit structure for TADS reporting unless it has two or more TADS AC Circuit Elements. Therefore, a structure with a 230 kV and a Non-BES 69 kV AC Circuit does not contribute to the tabulation of Multi-Circuit Structure Miles.
B	NOT APPLICABLE
C	The number of Multi-Circuit Structure Miles in the Voltage Class associated with AC Circuits reported by the TO at the end of the reporting year. This includes AC Circuits that are multiple-owner circuits that are reported by the TO. If you have no multi-circuit structures in a particular Voltage Class, a blank is the default entry in columns C, F, G, J, and K.
D-E	NOT APPLICABLE
F	The number of Multi-Circuit Structure Miles added in the Voltage Class associated with AC Circuits reported by the TO.
G	The equivalent number of Multi-Circuit Structure Miles added.
H-I	NOT APPLICABLE
J	The number of Multi-Circuit Structure Miles removed in the Voltage Class associated with AC Circuits reported by the TO.
K	The equivalent number of Multi-Circuit Structure Miles removed.
L	NOT APPLICABLE
M	This is a calculated value for the equivalent annual number of Multi-Circuit Structure Miles for the reporting year. Note that column J is not used; it is requested as a “sanity check” for column K.
N-Q	NOT APPLICABLE

Form 3.6: Common Corridors

The Common Corridor form, Form 3.6, is voluntary and only applicable to WECC entities. WECC TOs should use the established Common Corridor definitions to populate the form.

Chapter 4: Detailed Automatic Forms

Forms 4.1-4.4: Detailed Automatic Outage

These forms contain data for each Automatic Outage of an Element, both Sustained and Momentary, and do not have row numbers. Since each line represents an outage and each outage has a unique Outage ID Code, this code is used to identify each outage entry.

Since there is so much similarity between the columns, all descriptors will be provided once, using the generic term of “Element” instead of AC Circuit, Transformer, etc.

[Appendix D](#) provides many examples illustrating the completion of the various Form 4.x series.

Table 4.1: Data for Elements That Had an Automatic Outage

Column	Forms 4.1-4.4 Descriptor
A	The Outage ID Code assigned to the outage. This is assigned by the TO. See Appendix A for the definition of Outage ID Code. For any given TO, over multiple years, webTADS requires the TO entered Form 4.x Outage ID to be used only once on an Automatic Outage (on Form 4.x).
B	The Event ID Code associated with the outage. This is assigned by the TO on Form 5.0. See Appendix A for the definition of Event ID Code. The Event ID Code used on Form 4.x must be pre-defined on Form 5.0.
C	A TO defined unique Element Identifier. See column A in Table 3.1 for details.
The descriptions that follow use defined terms that the TO should become familiar with. Definitions of defined terms are located in Appendix A and they will not be repeated here. Most data fields have drop-down menus. They each describe various facets of the outage.	
D	The Fault Type (if any) for each circuit Outage, input from a drop-down menu.
E	The Outage Initiation Code, input from a drop-down menu.
F	The Outage Start Time. This may be local time or UTC time. WebTADS will offer a choice of time zones, with UTC being the default. This applies whether the data is entered directly into webTADS or bulk-uploaded via XML files (created either from an Excel workbook or directly by the TO). WebTADS will convert all non-UTC times to UTC and store the time as UTC within webTADS. The use of UTC will allow related outages occurring on Elements reported by different Transmission Owners to be linked. For Outages occurring on Elements that cross quarters, TOs should, in the first quarter, extend the length of the Outage to the end of the first quarter. In subsequent quarters, the Outage length should be extended until the end of the reporting year. Refer to the instructions in Section 4.1, below, for outages that continue beyond the end of the reporting calendar year.
G	The Outage Time Zone. The Time Zone of the reported Outage.
H	The Outage Duration expressed as hours and minutes. Momentary Outages will enter a “0” (zero). A zero entry in column M tells the reviewer that the outage was Momentary. See instructions in Section 4.1 below for outages that continue beyond the end of the reporting year. Note that the format is a text field and requires a colon (“:”) be entered between the hours and minutes. Enter 860 hours and 20 min. as 860:20. <i>If the colon is absent, the entry will be interpreted as “hours.”</i> If the Outage Duration exceeds the number of hours remaining in the year (based upon the Outage

Table 4.1: Data for Elements That Had an Automatic Outage

Column	Forms 4.1-4.4 Descriptor
	Start Time), the data will be rejected and an error notice provided. If the previous entry of “860:20” were entered as 86020, it would be read as 86,020 hours and rejected.
I	The Initiating Cause Code, input from a drop-down menu. All Outages must supply an Initiating cause code.
J	The Sustained Cause Code, input from a drop-down menu. This only applies to Sustained Outages. For Momentary Outages, enter “NA-Momentary.”
K	The Outage Mode, input from a drop-down menu.
L	The Outage Continuation Flag described whether the outages started and ended within the reporting year or not. The flag is explained in a footnote on the data form as well as in Appendix A where the term is fully defined. Outages that span across quarters in the same year should not use this flag. Instead, TOs should update the outage duration during each quarter until the outage ends.

Chapter 5: TADS Event Forms

Form 5.0: Event ID Codes

Single TADS Outages and every set of related TADS Outages are assigned to a TADS Event. An Event is a transmission incident that results in the Sustained or Momentary Outages of one or more Elements. If multiple Outages are associated to the same Event ID, they should occur within one minute of each other. The purpose of a TADS Event is to identify related Outages, if applicable. To accomplish this, TOs create their specific TADS events in TADS Form 5.0 and assign these Events to each associated TADS Outage. Specifically TOs assign their own Event ID Codes and associated Event Type Numbers. The table below describes the data collected for each TADS Event:

Table 5.1: Form 5.0 Field Descriptions

Column	Form 5.0 Descriptor
A	The Event ID Code associated with one or more outages. This is assigned by the TO. See Appendix A for the definition of Event and Event ID Code. For a given TO the same Event ID Code cannot be defined more than once on Form 5.0. The TO cannot define the same code again on Form 5.0 in any subsequent year.
B	The Event Type No. This is a descriptor of the Event. The table on Form 5.0 shows the permitted entries, which are in a drop-down menu. Note that if Event Type Number 11 is selected, the Outage Mode on Forms 4.1, 4.2, or 4.3 (column K) must be "Single Mode Outage." Table 2.9 and Table 2.10 show the possible Event Type Numbers. See Appendix A for the definitions of Normal Clearing, NCCBS, Abnormal Clearing, Delayed Fault Clearing, SPS or RAS, and Event Type Number. A consistent set of definitions is necessary to determine the Event Type Number to be entered in Column B.
C	<u>Optional input:</u> Provide a brief description of the Event's outage(s) for any Event ID Code. Please limit the description to 500 characters or less.
D	This field indicates whether a EOP-004 disturbance report was filed that was associated with the Event, with the choices contained in a drop-down menu (Yes, or No). TOs should speak with their Regional Entity Coordinator if they are unsure whether a particular transmission event had a disturbance report filed. For example, a TO will know which Region its facilities reside (Region ID), but the TO should also know the associated Balancing Authority (BA) identified by a BA ID. Since the posted information is available in an Excel file, a TO should first sort by its Region and BA to determine if any of its Events had a possible disturbance report associated with it. If no disturbances were reported for the TOs Region and BA, then the TO should answer "No." If some disturbances were reported, the TO should then examine the disturbance start and end dates and times on the posted information and compare them to the start and end dates and times associated with the individual outages associated with an Event ID. If this comparison shows that the TOs Event outage times are not inside any disturbance report time windows, then the TO should answer "No." On the other hand, if a disturbance time interval and an Event time interval overlap, the column with the "Event Description" may provide enough information to determine whether the TO should answer "Yes."

NERC Multiple Utility Event ID Code Creation

NERC Multiple Utility (NMU) Event ID Codes are special Event ID Codes that correlate multiple related Outages involving more than one TO that require more than one TO to report into the same Event ID Code. As part of the TADS program, TOs shall identify related multiple-TO Outages by using a single NMU Event ID Code. In contrast, related Outages occurring within only a single TO's territory are to be coded with the same Event ID Code created by that TO.

When a TADS Event involves related Outages impacting multiple TOs, each Outage shall use the same NMU Event ID Code. The TO on whose system the outage was initiated is responsible for creating the NMU Event ID Code. Once the NMU Event ID code is created, the responsible TO shall communicate the NMU Event ID to all involved TOs each of whom shall use that NMU Event ID for the group of Outages in the Event.

To create an NMU Event ID Code within webTADS, TOs should change the filter from their company to NERC within Form 5.0. Then, the TO creates an NMU TADS Event using the relevant interface buttons. WebTADS will automatically assign a new NMU Event ID for all involved TOs to use in their Outages for that Event.

Cascading Tolerance

If multiple Outages are associated to the same Event ID, they should occur within one minute of each other. If Outages are entered that are more than one minute apart, the Company user will receive an import warning message. An override must be requested in order for the Outages to be accepted as valid. When a Company user receives the tolerance warning message, a button labeled 'Request Override' is displayed at the bottom of the form page. When the 'Request Override' button is pressed, an email is sent to the Company user, NERC and the Regional contact. The Regional contact will then login and approve the override. This will change the read only field 'Extended Cascading Tolerance' on Form 5.0 from the default of No to Yes.

Event Type Numbers

Every TADS event is defined an Event Type Number to describe the general circumstances of the outage. A classification of the Event as Normal and Abnormal Clearing initially divides the Event Type Numbers. Then, Events with Normal Clearing are subdivided by the number of involved Elements, involvement of a bus section or common structure involvement. Abnormally Clearing Events are subdivided by the classification of breaker failure, dependability-based protection system misoperations, or security-based protection system misoperations.

Table 5.2: Event Type Number Descriptions: Events with Normal Clearing

Event Type No.	Description
05	Single bus section fault or failure resulting in one or more Automatic Outages.
06	Single internal circuit breaker fault resulting in one or more Automatic Outages.
11	Automatic Outage of a single Element not covered by Event Type Numbers 05 and 06.
13	Automatic Outage of two or more Elements within one Normal Clearing Circuit Breaker Set (NCCBS).
31	Automatic Outages of two or more TADS adjacent AC Circuits or DC Circuits on common structures. To qualify as Event Type Number 31 the Automatic Outages must be the direct result of the circuits occupying common structures.
49	Automatic Outage(s) with Normal Clearing not covered by Event Type Numbers 05 through 31 above.

All of the above Event Type Numbers, 05 to 49, are Events with Normal Clearing. For further explanations and examples regarding the determination of the proper Event Type Numbers, see Appendix A definitions for Normal Clearing, NCCBS, Abnormal Clearing, Delayed Fault Clearing, Special Protection System (SPS) or Remedial Action Scheme (RAS), and Event Type Number. These Event Type Numbers apply only when the Automatic Outages are the

result of Protection Systems and controls disconnecting the Elements that are expected to be automatically disconnected for a single event. In contrast, the term Abnormal Clearing is for an Event when Normal Clearing did not occur.

Table 5.3: Event Type Number Descriptions: Events with Abnormal Clearing

Event Type No.	Description
60	Breaker Failure: One or more Automatic Outages with Delayed Fault Clearing due to a circuit breaker being stuck, slow to open or failure to interrupt current.
61	Dependability (failure to operate): One or more Automatic Outages with Delayed Fault Clearing due to the failure of a composite protection scheme under either... a. failure to initiate the isolation of a faulted power system Element as designed, or within its designed operating time, or In the absence of a fault, failure to operate as intended within its designed operating time. (Item b is a very rare type of event.)
62	Security (unintended operation): One or more Automatic Outages caused by improper operation (e.g. overtrip) of a Protection System resulting in isolating one or more TADS Elements it is not intended to isolate, either during a fault or in the absence of a fault.
90	Automatic Outage(s) with Abnormal Clearing not covered by Event Types 60 through 62 above.

All of the above Event Type Numbers, 60 to 90, are Events with Abnormal Clearing. For further explanations and examples regarding the determination of the proper Event Type Numbers, see [Appendix A](#) definitions for Normal Clearing, NCCBS, Abnormal Clearing, Delayed Fault Clearing, SPS or RAS, and Event Type Number.

Non-TADS Element Outages

Please note: Event Type Number 11 (Automatic Outage of a single Element) is intended to include a single Automatic Outage resulting from one or more non-TADS Element outages. This type of Event should not be entered as Event Type Number 49 other Normal Clearing. If the Element outage results from one or more non-TADS Element outages, the Outage Initiation Code (Form 4) should be entered as “Dependent Mode”.

Event Type Number 13 versus Event Type Number 11

Event Type Number 13 is similar to Event Type Number 11 except a total of two or more Element outages occur within one NCCBS. By keeping type 13 separate from type 11, statistical granularity can be maintained in the annual report.

If two or more Automatic Outages occur (within one NCCBS) which result from one or more non-TADS Element outages, Event Type Number 13 should be entered and the Outage Initiation Code (Form 4) should be entered as “Dependent Mode” on each Automatic Outage. If two or more Automatic Outages occur outside of the Normal Clearing Circuit Breaker Set, do not enter Event Type Number 13. See the Event Analysis Guideline below.

Event Description

An optional event description may be entered on Form 5.0 in the Description column. In general for Event Type Numbers 05 to 31 (Normal Clearing), and Event Types 60 to 62 (Abnormal Clearing) a description is not needed but may be entered. However, for Event Type Number 49 (other Normal Clearing) or 90 (other Abnormal Clearing), entering a description of the Event would be helpful. Such a description, although not mandatory, would provide further clarification of these Events.

Event Analysis Guidelines

When using the revised Event Type Numbers, to reduce the amount of analysis labor required in determining the Event Type code numbers, the following systematic process contains a sample of logical questions and answers to determine the appropriate Event Type Number to be entered on Form 5.0. Several examples are included in this Instruction Manual with both the given Automatic Outage (Form 4.x) attributes and after using the Steps below, the appropriate determination of Event Type (Form 5.0). Data entries for each scenario are shown in tables along with each scenario. While not all possible situations could be covered, the examples are complete enough to illustrate Event Type determination.

The process below assumes that all Automatic Outage information required for completion of Form 4.x have already been collected and are available to the user. The user should be familiar with the TADS definitions in [Appendix A](#) for: Normal Clearing, NCCBS, Abnormal Clearing, Delayed Fault Clearing, SPS or RAS, Event, Event ID Code, and Event Type Number. Form 4.x data and associated event analysis are necessary for the determination of the Event Type number to be entered on Form 5.0. Event Type analysis should not begin until a complete set of Automatic Outages associated with each Event is ready for entry on Form 4.x including their associated event identification (Event ID) code.

The analysis Steps below are intended to reduce the labor resources to complete the determination of Event Type for entry on Form 5.0. The steps below will not reduce the labor needed to determine the Form 4 data to be entered for each Automatic Outage. This is a guideline and exceptions can be made as deemed necessary to determine the appropriate Event Type. It is anticipated that the overwhelming majority of Automatic Outages (2 of every 3 outages) will be a simple Normal Clearing of a single Element Automatic Outage which did not result from a bus outage or internal circuit breaker fault. For such cases, no additional resources will be necessary to determine the Event Type. Only Steps N1 and N3.1 below will be needed to determine the Event Type Number.

Event Type Number Determination

Begin at Step N1 with a set of one or more Automatic Outages entered on Form 4.x that has a unique Event ID Code. Follow the process until an Event Type Number for each Event is determined.

Step N1 - Normal Clearing determination

Did Abnormal Clearing occur? (Refer to examples below.)

- Yes – Proceed with Step A1 – Abnormal Clearing below.
- No – Proceed with Step N1 – Normal Clearing.

Example of an Event with Normal Clearing

For a given Event ID and its associated Automatic Outages, an Event which results from one or more unintended circuit breaker operations or unintended delayed clearing should be coded as Abnormal Clearing. Abnormal Clearing, per Section B definition, is the outage of a TADS Element that does not conform with Normal Clearing. For example, any unintended circuit breaker operations which occur beyond the NCCBS and results in a total of two or more Automatic Outages should be categorized as Abnormal Clearing.

Example of an Event with Normal Clearing beyond the NCCBS

SPS or RAS may normally trip additional 100 kV or above circuit breakers beyond the NCCBS. For a given Event ID and its associated Automatic Outages, an Event which results from one or more expected SPS or RAS normal operations should be coded as Normal Clearing.

Step N2 - Screen for Event Type Numbers 05 and 06

- If one or more Automatic Outages were the result of a Bus Section fault or failure, enter Event Type Number 05.

- If one or more Automatic Outages were the result of a single internal circuit breaker fault, enter Event Type Number 06.
- If not Event Type Number 05 or 06, then proceed with Step N3 below.

Step N3 – Screen for Event Type Numbers 11 and 13

- N3.1) If the Outage Mode Code was “Single Mode Outage”, enter Event Type Number 11.
- N3.2) For an Event ID with a total of two or more Automatic Outages that occur within one NCCBS, enter Event Type Number 13. The Outage Mode Codes on Form 4.x should be “Dependent Mode Initiating Outage” or “Dependent Mode Outage”.

If not Event Type Number 11 or 13, then proceed with Step N4 below.

Note: for a given Event ID code, each Automatic Outage on Form 4.x has one of the following Outage Mode Codes.

- Single Mode Outage
- Dependent Mode Initiating Outage
- Dependent Mode Outage
- Common Mode Outage
- Common Mode Initiating Outage

Step N4 – Screen for Event Type Number 31

- If two or more Automatic Outages of TADS adjacent AC Circuits or DC Circuits were the direct result of the Elements occupying common structures, enter Event Type Number 31.
- If not Event Type Number 31, then proceed with Step N5 below.

Step N5 – Screen for Event Type Number 49 – Other Normal Clearing

- If the Event included other Normal Clearing not covered by Event Type Number 05 to 31, enter Event Type Number 49.

Examples of an Event Type Number 49:

Event Type Number 49 includes, but is not limited to, Normal Clearing of two or more NCCBS. For example, an airplane crash causes Automatic Outages of two AC Circuits on a common right-of-way. Both circuits trip as expected with Normal Clearing. Event Type Number 49 should be used for such an event.

Event Type Number 49 also includes additional Automatic Outages with Normal Clearing that are initiated by SPS, RAS, Under Voltage Load Shedding (UVLS), Under Frequency Load Shedding (UFLS), etc.

Step A1 - Abnormal Clearing

- Did Abnormal Clearing occur? (Refer to examples in Step N1.)
 - Yes – Proceed with Step A2.
 - No – Return to Step N1.

Step A2 – Screen for Event Type Number 60; Breaker Failure

- Among the relay targets associated with this Event, did a breaker failure relay operation occur for one or more circuit breakers? Did this time-delayed relay operate as intended? If the answer to both of these questions is yes, enter Event Type Number 60. If one or more Automatic Outages experienced Delayed Clearing due to one or more circuit Breaker Failures (BF), enter Event Type Number 60. If the BF relay scheme did not operate as intended, go to Step A3 below.

Such delayed clearing examples include, but are not limited to, a circuit breaker being stuck, or slow to open, or failure to interrupt current. Such failures usually cause a circuit BF time-delayed relay to operate. Therefore, a BF relay target also occurs.

- If not Event Type Number 60, then proceed with Step A3 below.

Step A3 – Screen for Event Type numbers 61 and 62; Dependability or Security Failures

- Dependability (failure to operate); If one or more Automatic Outages experienced delayed clearing due to a Dependability failure to operate, enter Event Type Number 61.

A Dependability failure includes, but is not limited to, a failure of the Composite Protection System to:

- initiate the isolation of a faulted power system Element, or
- failure to operate within its designed operating time, or
- Failure to operate as intended for non-fault conditions within its designed operating time.
- Security (false or undesirable operations): If one or more Automatic Outages are caused by a Security failure, enter Event Type Number 62.

A Security failure includes improper operation of a Protection System (or its controls):

- in absence of a fault on the power system TADS Element, or
- during a fault it is not designed to protect.
- If not Event Type Number 60, 61 or 62 then proceed with Step A4 below.

Step A4 – Screen for Event Type Number 90; Other Abnormal Clearing

- If the Event included other Abnormal Clearing not covered by Event Type Number 60, 61 or 62, enter Event Type Number 90.

Example of an Event Type Number 90

Event Type Number 90 includes, but is not limited to, additional Automatic Outages with Abnormal Clearing that are initiated by SPS, RAS, UVLS, UFLS, etc. It also includes Abnormal Clearing of multiple faults or failures that are not covered by Event Type Number 60 to 62.

For additional examples for determining the Event Type Number for Normal Clearing and Abnormal Clearing Events, see [Appendix D](#) – Detailed Automatic Outage Data examples.

Chapter 6: Detailed Non-Automatic Outage Data

Forms 6.1-6.4

These forms contain data for *each* Non-Automatic Operational Outage of an Element and do not have row numbers. Since each line represents an outage and each outage has a unique Outage ID Code, this code is used to identify outage entry.

Table 6.1: Data for Elements That Had a Non-Automatic Outage

Column	Forms 6.1-6.4 Descriptor
A	The Outage ID Code assigned to the outage. This is assigned by the TO. See Appendix A for the definition of Outage ID Code. For any given TO, over multiple years, webTADS requires the TO entered Form 6.x Outage ID to be used only once on a Non-Automatic Outage (on Form 6.x).
B	A TO defined unique Element Identifier. Element Identifiers cannot be reused in any future reporting period for a different Element. If there are multiple owners of the Element, those TOs must agree on the Element Identifier.
C	Non-Automatic Outage Type. Please refer to Appendix A for the definition of Non-Automatic Outage Types.
The descriptions that follow use defined terms that the TO should become familiar with. They will not be repeated here. Most data fields have drop-down menus. They each describe various facets of the outage.	
D	The Outage Start Time. This may be local time or UTC time. WebTADS will offer a choice of time zones, with UTC being the default. This applies whether the data is entered directly into webTADS or bulk-uploaded via XML files (created either from an Excel workbook or directly by the TO). WebTADS will convert all non-UTC times to UTC and store the time as UTC within webTADS. The use of UTC will allow related outages occurring on Elements reported by different Transmission Owners to be linked. See instructions Section 4.1 below for outages that continue beyond the end of the reporting calendar year.
E	The Outage Time Zone. The Time Zone of the reported Outage.
F	The Outage Duration expressed as hours and minutes. Momentary Outages will enter a “0” (zero) in this field since we round to the nearest minute. A zero entry in column M tells the reviewer that the outage was Momentary. See instructions in Section 4.1 below for outages that continue beyond the end of the reporting year. Note that the format is a text field and requires a colon (“:”) be entered between the hours and minutes. Enter 860 hours and 20 min. as 860:20. <i>If the colon is absent, the entry will be interpreted as “hours.”</i> If the Outage Duration exceeds the number of hours remaining in the year (based upon the Outage Start Time), the data will be rejected and an error notice provided. If the previous entry of “860:20” were entered as 86020, it would be read as 86,020 hours and rejected.
G	The Operational Cause Code, input from a drop-down menu. This only applies to Operational Outages.
H	The Outage Continuation Flag described whether the outages stated and ended within the reporting year or not. The flag is explained in a footnote on the data form as well as in Appendix A where the term is fully defined.

Outages That Continue Beyond the End of the Year

Although data may be entered in local time, each TADS calendar year is equivalent to a UTC calendar year. Therefore, in the Eastern Time zone, the TADS calendar year begins on December 31 of the prior year at 7:00 p.m. Eastern Time. In the Pacific Time zone, the TADS calendar year begins on December 31 of the prior year at 4:00 p.m. Pacific Time. If an outage begins in a reporting calendar year and continues beyond the end of the year (December 31), the calculation of a total Outage Duration is not possible. In this case, the following process will be observed.

1. Two separate Outage Durations will be input.
 - a. For the reporting year when the outage started, the TO inputs the Outage Start Time and calculates an Outage Duration from the Outage Start Time until the end of the reporting calendar year. The Outage Continuation Flag is input as “1.” See [Appendix A](#) for a complete description of this flag.
 - b. For the next reporting year, the Outage Continuation Flag is input as “2” and the same Event ID Code (defined on the prior year Form 5.0) will be entered. The Outage Start Time is equal to January 1, 00:00 UTC of that reporting year. Each year the Outage ID code can be a duplicate of the Outage ID associated to the prior year’s Event ID or it can be unique. However, the same prior year Event ID Code should be used. If the outage is concluded in that reporting year, an Outage Duration is calculated from the Outage Start Time. If the outage continues to the subsequent reporting year, the Outage Duration is entered as 8760:00, or 8784:00 for a leap year. The Outage Continuation Flag is input as “2.”
 - c. Most outages that are not concluded by the end of a reporting year will conclude in the next reporting year. However, an outage may span three or more reporting years. This process described in “b.” above continues until the outage ends. The same Event ID Code (defined on Form 5.0 in the first year) is used for all subsequent years.
2. For purposes of calculating metrics, the metrics in the first reporting year will reflect the outages in that year for frequency calculations. However, the Outage Duration will be split between reporting years as described above, and any outages with Event ID Codes from the prior year will not be counted towards the frequency calculation in subsequent years. An outage with a Continuation Flag equal to “2” is ignored in the frequency calculations. However, such an outage is included in the calendar year duration calculations.

Long Duration Outages

Treat long-term outages as follows:

1. If the equipment were to return to service at some date in the future, the outage reported in each reporting year and the continuation flag would be marked as noted in the section above.
2. If the equipment is going to be retired, then the outage would be marked as complete on the day of the decision and the Element Inventory would be marked as retired on the day of the decision.
3. If the equipment returns to service for one minute or more and then is removed for long-term repairs, the outage is completed and the outage converted to a planned outage. Planned outages are not reportable to TADS.

Appendix A: Definitions

TADS Population Definitions

Element

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

1. AC Circuits (Overhead and Underground)
2. Transformers⁵
3. AC/DC Back-to-Back Converters
4. DC Circuits (Overhead and Underground)

A TADS reportable Element may also be referred to as a “TADS Element” in the DRI. They have the same meaning.

A non-TADS Element is one of the four types of Elements listed above that does not qualify within the BES definition.

Protection System

The NERC Glossary of Terms used in NERC Reliability Standards defines Protection System as follows:

- Protective Relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

For coding outages as protection system equipment see the definition of the cause code failed protection system equipment.

AC Circuit

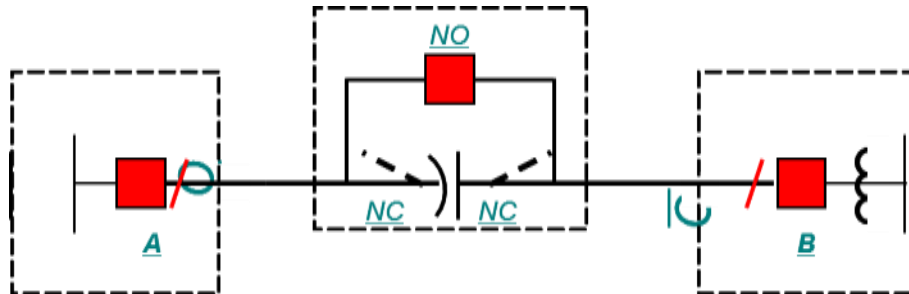
A set of AC overhead or underground three-phase conductors that are bound by AC Substations. Radial circuits which are BES Elements are to be included in AC Circuits.

The boundary of an AC Circuit extends to the transmission side of an AC Substation. A circuit breaker, Transformer, and their associated disconnect switches are not considered part of the AC Circuit, but they are defined, instead, as part of the AC Substation.

The AC Circuit includes the conductor, transmission structure, joints and dead-ends, insulators, ground wire, and other hardware. In addition, the AC Circuit includes in-line switches used to sectionalize portions of the AC Circuit as well as series compensation (capacitors and reactors) that is within the boundaries of the AC Circuit even if these ‘in-line’ devices are within an AC Substation. If these devices are not within the AC Circuit boundaries, they are not part of the AC Circuit but instead are part of the AC Substation.

⁵ Generator step-up units are not included in TADS-reportable Transformers.

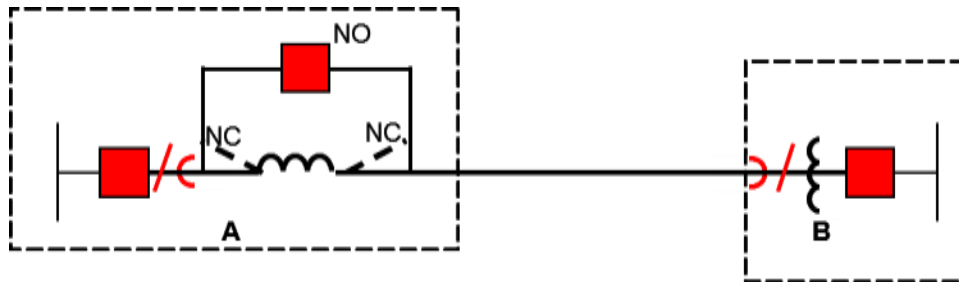
The diagrams on the next several pages explain this concept. The red arcs define the AC Circuit boundaries.⁶ In [Figure A.1](#), the series capacitor, bypass circuit breaker, and numerous disconnect switches are in a fenced AC Substation that is within the boundaries of the AC Circuit itself. When the series capacitor is connected and the bypass breaker is open, the capacitor and its disconnect switches are part of the AC Circuit. When the bypass breaker is closed, the bypass breaker and its disconnect switches (not shown) are part of the AC Circuit.



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

Figure A.1

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



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

Figure A.2

⁶ To simplify future diagrams, disconnect switches may not be shown.

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

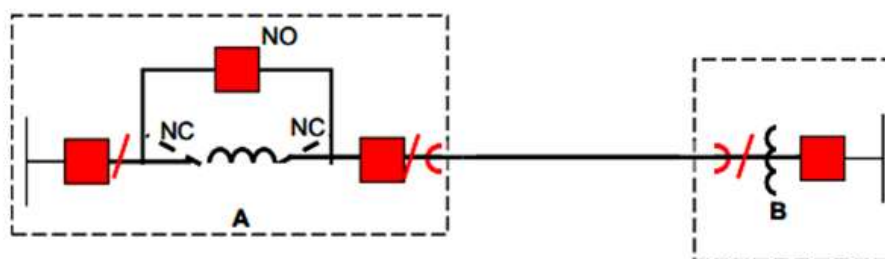


Figure A.3

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.

Terminal

Terminals are those buses on the Element, behind which exist power sources. In general, these terminals will comprise the set of locations that need to open to clear faults on the Element. Buses connected to the Element that serve only load, without power sources available behind them are not considered terminals.

AC Substation

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

AC/DC Terminal

A terminal that includes all AC and DC equipment needed for DC operation such as PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors and DC filters. On the AC side, an AC/DC Terminal is normally bound by AC breakers at the AC Substation bus where it is connected. On the DC side, it is bound by DC converters and filters. Protection System equipment is not part of the DC Terminal.

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.

DC Circuit

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

Overhead Circuit

An AC or DC Circuit that is not an Underground Circuit. A cable conductor AC or DC Circuit inside a conduit that 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.

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.

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. In addition, a one mile-long, common-trenched, double-AC Circuit Underground duct bank that carries two three-phase circuits would equate to two Circuit Miles.

Multi-Circuit Structure Mile

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

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

Voltage Class

For BES Elements only, the following voltages classes will be used for reporting purposes:

1. 0 – 99 kV⁷
2. 100 – 199 kV
3. 200 – 299 kV
4. 300 – 399 kV
5. 400 – 599 kV
6. 400 – 499 kV*
7. 500 – 599 kV*
8. 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 to the transformer’s secondary voltage. Voltages are operating voltages.

Generator Lead Lines

Generator leads are defined as the three phase connection from the primary side of the GSU to the first fault interrupting device. Regardless of length, these Elements are considered part of the Generating Equipment and are not reportable to TADs in either outages or inventory.

⁷ Only Elements within the BES would be included in this Voltage Class. For consistency with the other Voltage Classes, the TADS Reporting Workbook refers to this Voltage Class as 0 – 99 kV, but the term “Less than 100 kV (BES Only)” is equivalent.

*Only DC Circuits are applied to these voltage classes.

TADS Population Outage Definitions

Automatic Outage

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

Momentary Outage

An Automatic Outage with an Outage Duration less than one (1) minute. If the circuit recloses and trips again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered as two outages. Only 200kV and above Elements have reportable momentary outages.

Sustained Outage⁸

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

Non-Automatic Outage

An outage that results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State. Includes outages caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities.

Planned Outage

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

Operational Outage

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

In-Service State

An Element that is energized and connected at all its terminals to the system for at least one minute. Examples of reportable AC Circuit and Transformer Automatic Outages are illustrated below. An exclusion example is demonstrated in [Figure A.7](#) on page 29.

In [Figure A.4](#), AC Circuit A is bound by the disconnect switches (not shown)⁹ of two breakers, and Transformer A is bound by a breaker and a disconnect switch. AC Circuit B is bound by a breaker and a disconnect switch, and Transformer B is bound by a breaker and a disconnect switch. A 230 kV bus fault opens the green breakers. The TADS Transformers each report an outage. AC Circuit A reports an outage, but AC Circuit B does not. It is defined by the

⁸ The TADS definition of Sustained Outage is different from the NERC *Glossary of Term Used in Reliability Standards* definition of Sustained Outage that is presently only used in FAC-003-1. The glossary defines a Sustained Outage as: "The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." The definition is inadequate for TADS reporting for two reasons. First, it has no time limit that would distinguish a Sustained Outage from a Momentary Outage. Second, for a circuit with no automatic reclosing, the outage would not be "counted" if the TO has a successful manual reclosing under the glossary definition.

⁹ For simplification, disconnect switches may not be show in some figures. When a circuit breaker or Transformer disconnect switch define an AC Circuit boundary, we may just refer to the circuit breaker and the Transformer as defining the boundary without reference to their disconnect switches.

breaker on the left and the disconnect switch on the right. Since the breaker associated with AC Circuit B did not experience an automatic operation, it was not outaged because the disconnect switch on the AC Circuit B side of Transformer B remains connected. It remains connected at all its terminals by the breaker and the disconnect switch.

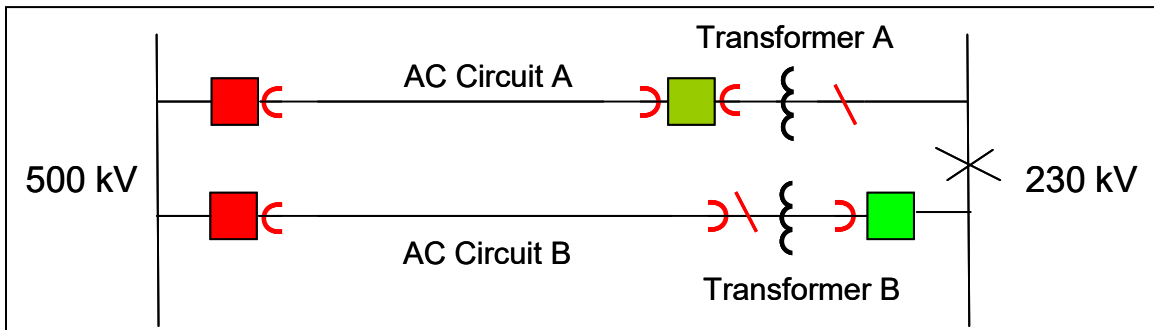


Figure A.4

In [Figure A.5](#), a similar situation exists except that the Transformers are not reportable since their secondary voltages are less than 100 kV. The AC Circuit outages are reportable exactly the same as in [Figure A.4](#); however, the Transformer outages are not reportable because Transformer B is not a BES Element.

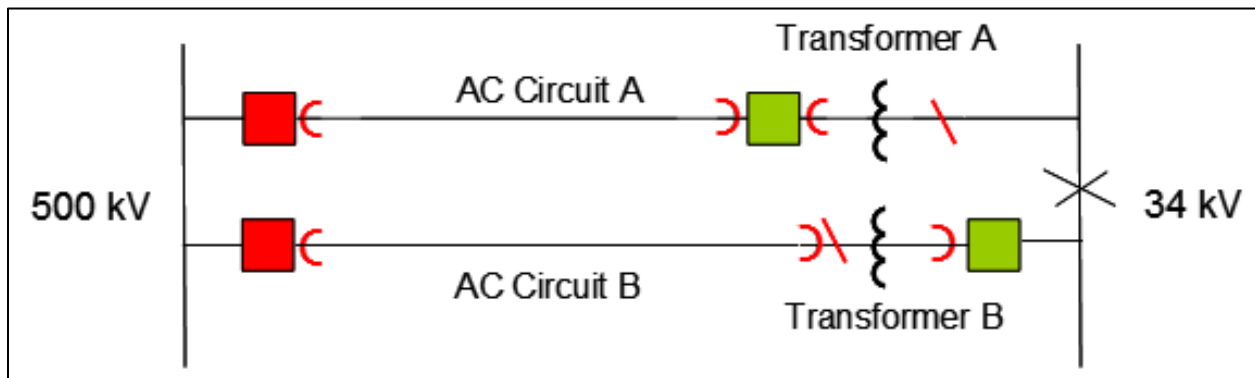


Figure A.5

In [Figure A.6](#), AC Circuit 22, the only source connecting AC Substations A and B, has a fault. As a result, AC Circuits 84 and 88 are de-energized but remain connected at all their terminals. Three outages are reported: circuits 22, 84 and 88. None of them meets the In-Service State requirement of being energized *and* connected at all their terminals.

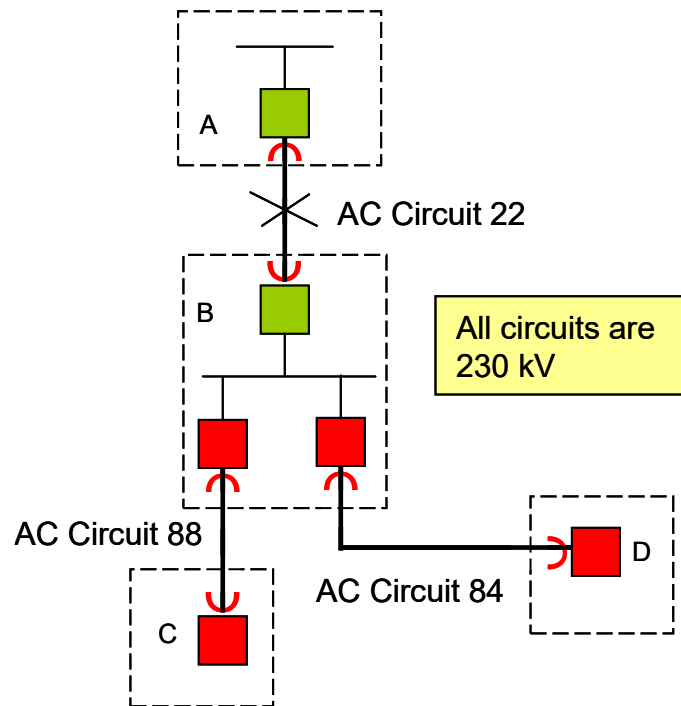


Figure A.6

Multi-Terminal AC Circuit with Tapped Transformer and Shared Breaker Exception

An exception that an Element be “connected at all its terminals” to be considered in an In-Service State is provided for a multi-terminal AC Circuit with a Transformer on one terminal that shares a breaker with the circuit.

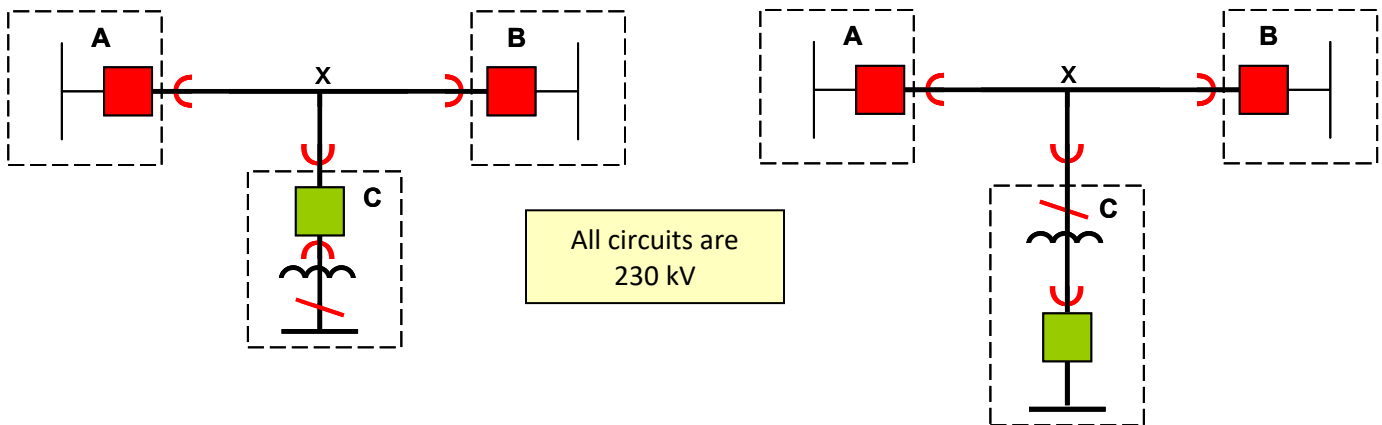


Figure A.7

Figure A.8

In both **Figures A.7** and **A.8**, the AC Circuit is bounded by AC Substations “A,” “B,” and “C” as indicated by the red arcs. Each Transformer’s boundaries are the red disconnect switch and the red arc before the breaker. Note that the Transformer in either figure may *or* may not be a reportable Element (i.e., one with a secondary voltage ≥ 100 kV).

Assume that each Transformer is out of service because of the operation of its associated breaker (indicated in green). In [Figure A.7](#), the AC Circuit would normally be considered out of service since the breaker at AC Substation C, which is shared by the AC Circuit and the Transformer, is open. Nevertheless, if all other portions of the AC Circuit are in service, the entire AC Circuit is considered to be in an In-Service State even if the Transformer is out of service. Because TADS does not recognize partial outage states, the multi-terminal exception, above, was developed to avoid

overstating the outage contribution of a multi-terminal configuration of this type. In [Figure A.78](#), the AC Circuit does not share the open breaker, and the AC Circuit remains connected. Thus, the exception does not apply in this case since the AC Circuit is connected at all its terminals even though the Transformer is out of service.

Substation, Terminal, or Converter Name

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

TO Element Identifier

An alphanumeric name that the TO must enter to identify the Element which is outaged (e.g., a circuit name). This identifier must be unique and consistent from year to year.

Outage Start Time

The date (mm/dd/yyyy) and time (hhhh:mm), rounded to the minute, that the Automatic Outage or Non-Automatic Outage of an Element started. Outage Start Time may be expressed in Coordinated Universal Time (UTC) or in local time.

Outage Duration

The amount of time from the Outage Start Time to when the Element is returned to its pre outage configuration In-Service State as define above. Outage Duration is expressed as hours and minutes, rounded to the nearest minute. Momentary Outages are assigned a time of zero Outage Duration.

Outage Continuation Flag

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

Table A.1: Outage Continuation Flags

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

Outage Identification (ID) Code

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

Normal Clearing

The NERC Glossary of Terms definition of Normal Clearing is:

“A Protection System¹⁰ operates as designed, and the fault is cleared [by the NCCBS, defined below] in the time normally expected with proper functioning of the installed Protection System” [clarification added in brackets].

For TADS purposes, Normal Clearing also includes a Protection System operating as designed for a non-fault condition where an Automatic Outage occurs as expected with proper functioning of the installed Protection System. The

¹⁰ This definition is in the current NERC *Glossary of Terms Used in Reliability Standards*. Although the term “protection system” is not capitalized in the *Glossary*, we have capitalized it here because we believe it has the same meaning.

Normal Clearing definition applies to the opening of circuit breakers. Subsequent automatic reclosing by the Protection System is not included in the Normal Clearing period.

An example of a Normal Clearing event where the reclosing did not function properly would be if an AC Circuit is struck by lightning (with no damage to the equipment), and the Protection System clears the fault as designed (Normal Clearing). However, the Protection System automatic reclosing equipment fails to re-energize the AC Circuit. It was expected that the breakers would reclose and return the line to an In-Service State. Even though the Protection System failed to reclose properly, the above sequence of events is still an example of Normal Clearing as defined above. The Initiating Cause Code would be “Lightning”, and the Sustained Cause Code would be “AC Substation.”

Normal Clearing Circuit Breaker Set (NCCBS)

The set of circuit breakers that would open to isolate a fault on a given Element under Normal Clearing.

For each Element by design, a given set of circuit breakers trip in order to interrupt fault current (if a fault occurred on the Element). In general, this set of circuit breakers may be determined by examining an Elementary single line diagram of the circuit that includes the TADS defined Element. Please note when this given set of circuit breakers open, two or more Elements may change to a not In-Service State and therefore become reportable Automatic Outages. In such a case, these Outages are reportable as one Event, and the same Event ID should be used for each of the Outages.

For example, see the above [Figure A.78](#). For purposes of this example, the 230 kV AC Circuit is tapped by a 230 kV/69 kV transformer, which has a low side 69 kV circuit breaker. However, as shown on [Figure A.78](#), the transformer does not have a high side 230 kV circuit breaker. In such a case, the NCCBS for this TADS 230 kV AC Circuit includes the 69 kV circuit breaker as part of the expected Normal Clearing if a fault occurs on the TADS Element. The three circuit breakers shown on [Figure A.78](#) are the NCCBS including the 69 kV circuit breaker.

Abnormal Clearing

The outage of a TADS Element that does not conform with Normal Clearing in all aspects.

For a given Event ID and its associated Automatic Outages, an Automatic Outage that results from one or more unintended BES Element circuit breaker operations outside the NCCBS should be categorized as Abnormal Clearing.

Example Event ID 17A: See the above [Figure A.6](#). The NCCBS for “AC Circuit 22” is circuit breaker A and circuit breaker B. During an event where an Automatic Outage of “AC Circuit 22” occurs, if 230 kV circuit breaker D also trips, the Automatic Outage of “AC Circuit 84” is the result of Abnormal Clearing. Since one of the Automatic Outages is the result of Abnormal Clearing, Event ID 17A is an Abnormal Clearing event.

Example Event ID 17B: On the contrary, during an event where an Automatic Outage of “AC Circuit 22” occurs ([Figure A.6](#)), if the 69 kV circuit breaker C on [Figure A.78](#) also trips, the 230 kV/69 kV transformer outage is not a reportable Automatic Outage. Since the only Automatic Outage is “AC Circuit 22” and it is the result of Normal Clearing, Event ID 17B is a Normal Clearing event.

Improper operation of Protection System automatic reclosing is not considered Abnormal Clearing. Reclosing is a separate function and occurs after circuit breaker clearing.

Delayed Fault Clearing is considered Abnormal Clearing. See definition below.

Delayed Fault Clearing

Fault clearing consistent with correct operation of a breaker failure Protection System and its associated breakers, or of a backup Protection System with an intentional time delay.

Example Event ID 18A: See Figure A.6. For the purpose of this example, the correct operation of the Protection System for “AC Circuit 22” normally clears both circuit breakers A and B in less than four cycles. However, if the primary Protection System fails (no primary relay targets) and the backup Protection System operates (with an intentional time delay relay target) then this Automatic Outage includes Delayed Fault Clearing. Since the Automatic Outage includes Delayed Fault Clearing, Event ID 18A is an Abnormal Clearing event.

Special Protection System (SPS) or Remedial Action Scheme (RAS)

“An automatic Protection System designed to detect abnormal or predetermined system conditions and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.”

The above definition is from the NERC Glossary of Terms. As designed, a SPS or RAS may normally trip additional circuit breakers beyond the NCCBS. For a given Event ID and its associated Automatic Outages, an Event which results from one or more expected SPS or RAS normal operations should be categorized as Event Type Number 49 (Other Normal Clearing). Abnormal SPS or RAS operations should be categorized as Event Type Number 90 (Other Abnormal Clearing).

Event

An Event is a transmission incident that results in the Automatic Outage (Sustained or Momentary) of one or more Elements. These Outages typically occur within one minute of each other.

Event Identification (ID) Code

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

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

Event Type Number

A code that describes the type of Automatic Outage(s) that occurred.

Two tables are provided for Event Type Numbers that fall into two distinct categories.

Normal Clearing: This table applies under two conditions:

1. When a fault has occurred, and the Element is isolated under Normal Clearing.
2. When a fault has not occurred, but the Element is isolated by the proper operation of the Protection System. For example, a circuit breaker may be opened due to the detection of circuit breaker low gas pressure, causing the Protection System to operate. Alternatively, the Protection System due to high oil temperature may isolate a Transformer. Both of these events are categorized as Normal Clearing.

Abnormal Clearing: This table applies under two conditions:

1. When a fault has occurred, and the Element is isolated under Abnormal Clearing.

- When a fault has not occurred, but the Element is isolated by the failure or unintended operation of the Protection System.

An example of Abnormal clearing would be when a low gas pressure sensor, part of the Protection System, provides an incorrect sensor reading and causes the Protection System to operate when it would not otherwise have operated. Since the sensor and its controls are part of the Protection System, its operation is abnormal (not proper). The isolation of the Element was due to the Protection System's improper operation of a protection sensor. Since an Automatic Outage was due to Abnormal Clearing, the event is categorized as Abnormal Clearing.

Another example of Abnormal Clearing is caused by an improper relay setting (either during design or by misapplication) that causes an unintended outage of one or more Elements.

Table A.2: Event Type Number Descriptions: Events with Normal Clearing¹

Event Type No.	Description
05	Single bus section fault or failure resulting in one or more Automatic Outages.
06	Single internal circuit breaker fault resulting in one or more Automatic Outages ² .
11	Automatic Outage of a single Element not covered by Event Type Numbers 05 and 06.
13	Automatic Outage of two or more Elements within one NCCBS.
31	Automatic Outages of two or more TADS adjacent AC Circuits or DC Circuits on common structures. To qualify as Event Type Number 31 the Automatic Outages must be the direct result of the circuits occupying common structures ³ .
49	Automatic Outage(s) with Normal Clearing not covered by Event Type Numbers 05 through 31 above ⁴ .

Table A.3: Event Type Number Descriptions: Events with Abnormal Clearing⁵

Event Type No.	Description
60	Breaker Failure: One or more Automatic Outages with Delayed Fault Clearing due to a circuit breaker being stuck, slow to open or failure to interrupt current.
61	Dependability (failure to operate): One or more Automatic Outages with Delayed Fault Clearing due to failure of a single Protection System (primary or secondary backup) under either of these conditions: - failure to initiate the isolation of a faulted power system Element as designed, or within its designed operating time, or - In the absence of a fault, failure to operate as intended within its designed operating time. (Item b is a very rare type of event.)
62	Security (unintended operation): One or more Automatic Outages caused by improper operation (e.g. overtrip) of a Protection System resulting in isolating one or more TADS Elements it is not intended to isolate, either during a fault or in the absence of a fault.
90	Automatic Outage(s) with Abnormal Clearing not covered by Event Types 60 through 62 above ⁶ .

Notes:

- Event Type Numbers 05 to 49 are Events with Normal Clearing. These Event Type Numbers apply only when the Automatic Outages are the result of Protection Systems and controls disconnecting the Elements that are

expected to be automatically disconnected for a single event. Normal Clearing is defined in the NERC *Glossary of Terms Used in Reliability Standards*:

2. *"A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."*

An internal breaker fault means a breaker failing internally. This creates a system fault, which must be cleared by protection on both sides of the breaker.

3. As stated in the TADS definition of Multi-Circuit Structure Mile:
"... If a line section contains two or more Multi-Circuit Structures which form one or more multi-circuit spans, the total span length can be measured, and the associated mileage should be reported in the 'Multi-Circuit Structure Mile' total inventory. If multiple circuits are connected to only one common structure, that structure should be ignored for outage and inventory mileage purposes."
4. Event Type Number 49 also includes Automatic Outage(s) initiated by normal operation of a Special Protection System (SPS) or Remedial Action Scheme (RAS). SPS (a.k.a. RAS) are defined in the NERC Glossary of Terms. For convenience, this SPS definition has also been added to [Appendix A](#).
5. Event Type numbers 60 to 90 are Events with Abnormal Clearing. These Event Type numbers apply when Normal Clearing (see Note 1) does not occur for any one or more Automatic Outage associated with the Event.
6. Event Type 90 also includes Automatic Outage(s) initiated by abnormal operation of a Special Protection System (SPS) or Remedial Action Scheme (RAS).

Event Type No. 11 and 13 Examples

1. For example, suppose a 500 kV AC Circuit is outaged and results in a tapped 500/230 kV Transformer outage due to Normal Clearing. This is an example of Event Type #13.
2. If the Transformer in the previous example had been a 500/69 kV Transformer, the Transformer would not be an Element and, therefore, only the AC Circuit outage would be reported in TADS. This is an example of Event Type #11.

Event Type No. 31 Examples

To qualify for an Event Type No. 31, the outages must be a direct result of the circuits occupying common structures. These characteristics will generally apply.

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

These are examples of Events that are Event Type No. 31:

1. A tornado outaged two 230kV AC Circuits on common structures. In this example, the outages are Element-Initiated and Common Mode. This is an Event Type No. 31 because the loss of both circuits was directly related to them being on the same structures.
2. On one 230kV AC Circuit, a conductor breaks (outaging the circuit), and the conductor swings into a second 230kV AC Circuit on common structures. The first circuit outage is Element-Initiated and Dependent Mode Initiating; the second circuit outage is Other-Element Initiated and Dependent Mode. This is an Event Type No. 31 because the second circuit's outage was a result of it being on common structures with the first circuit.

These Events are not an Event Type No. 31:

1. Two 230kV AC Circuits on common structures are outaged due to a bus fault in the AC Substation where the circuits terminate. Both outages are AC Substation-Initiated and Common Mode. Because the outages are not a result of the two circuits being on common structures, it is not an Event Type No. 31. It is an Event Type No. 05.
2. Two 230kV AC Circuits are on common structures and terminate at the same bus. Lightning strikes one of the 230kV circuits, but the breaker fails to open due to a failure of a relay to operate properly. The second circuit, which is connected to the same bus, is outaged because of the failure of first circuit's breaker to open. The first outage is an Element-Initiated and Dependent Mode Initiating; the second outage is Protection System-Initiated and Dependent Mode.

(Note: the relay is excluded as part of an AC Substation, making the Outage Initiation Code "Protection System-Initiated" and not "AC Substation-Initiated.") Because the outages are not a result of the two circuits being on common structures, it is not an Event Type No. 31. It is an Event Type No. 61.

Fault Type

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

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

The term "associated with" could be broadly interpreted to mean any fault, no matter how remote, which results in an Automatic Outage of an Element. This is not intended. Therefore, the following guide is to be used for reporting Fault Type. This guide uses the Outage Initiation Codes described in Section C below.

If an Element has an Automatic Outage and its Outage Initiation Code is:

- "Element-Initiated," report the Fault Type from one of the five above.
- "Other Element-Initiated," report "No fault" as the Fault Type for the outage since a Fault Type will be reported for the other Element that initiated the outage.
- Either "AC Substation-Initiated" or "AC/DC Terminal Initiated," report Fault Types from 2-5 above ONLY if a fault occurred on AC equipment that is within the BES. Otherwise, report "No fault" if a fault did not occur OR if a fault occurred, but it occurred on AC equipment outside of the BES (generally less than 100 kV).
- "Other Facility-Initiated," or "Protection System-Initiated," report "No fault" as the Fault Type.

The Fault Type for each Element outage may be determined from recorded relay targets or by other analysis. TOs should use the best available data to determine (1) whether a fault was associated with the outaged Element and, if so, (2) what type of fault occurred.

Relay targets are not a foolproof method to determine the Fault Type; however, they may be the best available data to determine Fault Type. Relay targets should be documented as soon as practical after a fault and the targets re-set to prepare for the next fault. If a single fault results in several Element outages, the protective relay targets associated

with each Element indicate the Fault Type for that Outage. An Element whose relays did not indicate a fault should be reported as “No fault.”

Example 1

A 500 kV AC Circuit experiences a single phase-to-ground fault on the Element, outaging the Element. The AC Circuit outage also results in an outage of a 500 kV/230 kV Transformer that is connected to the 500 kV circuit. The Transformer did not experience a fault. The AC Circuit’s Outage Initiation Code would be “Element-Initiated” and its Fault Type would be “Single P-G fault.” The Transformer’s Outage Initiation Code would be “Other Element-Initiated” and its Fault Type would be “No fault.” See bullets “a.” and “b.” above.

Example 2

A 500 kV AC Circuit trips when its relays operate due to a Protection System misoperation for a single phase-to ground fault on a 500 kV/69 kV Non- BES Transformer. The AC Circuit’s “Outage Initiation Code” should be entered as “Protection System-Initiated” because it initiated on the Protection System, which misoperated. The AC Circuit outage fault type should be reported as “No fault.” It does not matter if the fault was on the 500 kV or 69 kV side of the Transformer for this example. See bullet “d.” above. Note that the Transformer outage will not be reported since it is not a TADS Element.

Outage which has more than one Fault Type

An Element outage may have occurred due to multiple reclosing and tripouts prior to lockout (Sustained Outage) of the Element. In such a case during each reclosure, different relay targets may have been initiated. The fault type may not have stayed the same during each reclosure. Many relay targets do not have a recorded time stamp. Therefore, the type of fault during each reclosure may not be known. It is recognized that the resulting list of relay targets is not a foolproof method to determine the Fault Type. However, the TO should use their best judgment on the type of fault encountered from a dynamic stability point of view.

Guidelines

The worst type of fault for dynamic stability is generally the above type 4 – “Phase-to-phase-to-ground (P-P-G), 3P or 3P-G fault”. If both Phase and Ground targets have been recorded without time stamps and are the only information available, the TO should use their best judgment whether item 4 above should be reported as the Fault Type.

A lower impact fault on dynamic stability is the above item 2 – “Phase-to-phase fault (P-P)”. The least impact fault is generally the above item 3 - “Single phase-to-ground fault (P-G)”. It is recognized that a P-G type of fault may produce the highest single-phase fault current. However, for TADS purposes the Fault Type chosen, based on TO best judgment of what occurred, should represent the worst impact on system dynamic stability. This guideline can be clarified by the following Example:

Example 4a - Assume the following actual situation occurred at the site:

A 230 kV AC circuit trips at both terminals due to a long horizontal antenna wire contacting the line. A bright arc occurs from one phase along the antenna wire to the grounded antenna mast. The bright arc disappears. Within a few seconds, the antenna wire melts and whips across two phases. After 15 seconds, a bright arc occurs from one phase to the second phase. The arc does not travel to the antenna mast. The bright arc disappears. The AC conductor is not badly damaged, and the conductor has returned to an energized condition. No one reports the above fireworks to the local utility.

Utility knowledge of the above event:

A momentary outage occurred on 230 kV AC Circuit X-Y:

Both terminals X and Y initially tripped. After 15 seconds, terminal X auto-reclosed and tripped. After 15 more seconds, terminal X auto-reclosed and held. After 5 more seconds, terminal Y auto-reclosed and held. Therefore, the circuit was returned to an in-service state in 35 seconds.

The utility did not have sequence of events or fault recorders at Substation X or Substation Y. From the utility office, a relay technician dials-in to each substation to read the relay target information at generation Substation X and system Substation Y. The recorded protective Relay Targets are: Instantaneous “Ground” current relay target at both terminals X and Y (with no timestamp on the relay targets). Terminal X also has an instantaneous “Zone 1 Phase” relay target (with no time stamp). No other information is available.

It is recognized that perfect information is not always available to the Utility. In such a case, the Fault Type reported in TADS should be type 4 – “Phase-to-phase-to-ground (P-P-G), 3P, or 3P-G fault” which would indicate the worst type of fault, generally, for system stability.

Example 4b - 10 years later, the above event occurs again. However, within that 10-year period digital relays with time stamped Relay Targets have been installed.

The protective relay targets reported are: Instantaneous “Ground” current relay target (at time equal zero) at generation Substation X and system Substation Y. [No Phase relay target at time zero.] Substation X also has an instantaneous “Zone 1 Phase” relay target (at time equal 15 seconds). [No additional “Ground” targets at time equal 15 seconds.] With the new timestamp information, the fault impact on dynamic stability can now be properly reported. Based on the timestamp information, the Fault Type reported in TADS should be type 2 – Phase-to-Phase fault (P-P). For this example, analysis showed that the initial Single Phase to Ground fault had less impact. The actual fault type was not type 4 Phase-to-phase-to-ground (P-P-G).

Relay targets are not a foolproof method to determine the Fault Type; however, they may be the best available data to determine Fault Type. In all cases, the TADS outage should use the applicable Fault Type that is determined.

Outage Initiation Codes

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

Element-Initiated Outage

An Automatic Outage of a TADS Element that is initiated on or within the TADS Element that is outaged. (Note: Only used for TADS Element.)

Other Element-Initiated Outage

An Automatic Outage of a TADS Element that is initiated by another TADS Element and not by the TADS Element that is outaged. (Note: Only used for TADS Element.)

AC Substation-Initiated Outage

An Automatic Outage of a TADS Element that is initiated on or within AC Substation facilities. (Note: By the definition of “AC Substation” in Section A, Protection System Equipment is not part of the AC Substation; it is therefore included in “Protection System-Initiated Outage.” Only used for TADS Element.)

AC/DC Terminal-Initiated Outage

An Automatic Outage of a TADS Element that is initiated on or within AC/DC Terminal facilities. (Note: By the definition of “AC/DC Terminal” in Section A, Protection System Equipment is not part of the DC Terminal; it is therefore included in “Protection System-Initiated Outage.” Only used for TADS Element.)

Protection System-Initiated Outage

An Automatic Outage of a TADS Element that is initiated on or within the Protection System. (Note: This includes Automatic Outages due to the failure of a Protection System Element initiated by protection equipment (including, but not limited to incorrect protection settings, wiring errors, miscoordination, Protection System related Human Error, etc.) causing the protection system to misoperate. Only used for TADS Element.)

Other Facility-Initiated Outage

An Automatic Outage that is initiated on or within other facilities. “Other facilities” include any facilities not includable in any other Outage Initiation Code. (Note: Only used for non-TADS Element.) Mode code is always “Dependent Mode Outage”.

Outage Initiation Code Examples

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

Outage Mode Codes

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

Single Mode Outage

An Automatic Outage of a single Element that occurred independent of any other Automatic Outages (if any).

Dependent Mode Initiating Outage

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

Dependent Mode Outage

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

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).

Common Mode Initiating Outage

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

Dependent Mode and Common Mode Outage Examples

- **Example 1** - A Dependent Mode Outage involves two or more outages, but one of the outages can be a non-TADS Element outage. Therefore, not all Dependent Mode Outages will have an associated Dependent Mode Initiating Outage. If the initiating outage is one of the four defined Elements, that outage will be a Dependent Mode Initiating Outage, and the resulting second Element outage will be a Dependent Mode Outage. For

example, suppose a 500 kV AC Circuit is outaged because of a 500/230 kV Transformer outage. The AC Circuit outage is a Dependent Mode Outage, and the Transformer outage is a Dependent Mode Initiating Outage. However, if an outage is not initiated by an Element, it will not have an associated Dependent Mode Initiating Outage. If the Transformer in the previous example had been a 345/68 kV Transformer and the AC Circuit a 345 kV circuit, the Transformer would not be an Element and, therefore, the AC Circuit outage would not have an associated Dependent Mode Initiating Outage. The AC Circuit outage would be classified as a Dependent Mode Outage since it was the result of a non-TADS Element outage.

- **Example 2** - A Common Mode Outage involves two or more outages, but unlike a Dependent Mode Outage, all outages must be Elements. In addition, one outage must not cause the other outage(s) to occur; i.e., the outages are not consequences of each other. In addition, they must occur nearly simultaneously.
 - As an example, suppose that lightning strikes two AC Circuits in the same right of way (but not necessarily on a common structure) and both circuits are outaged nearly simultaneously. Assume no further outages occur. Both are Common Mode Outages.
 - Now assume the same scenario with a slight difference: one AC Circuit clears normally, the second AC Circuit does not, and there is a circuit breaker failure, resulting in the outage of two additional AC Circuits. The first AC Circuit outage is a Common Mode Outage. The second AC Circuit outage is a Common Mode Initiating Outage, with the two additional AC Circuit outages both being Dependent Mode Outage (if it had only been one additional outage it would also have been Dependent Mode).

Automatic Outage Cause Code Types

Initiating Cause Code

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

Sustained Cause Code

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

Initiating and Sustained Cause Code Examples

- **Example 1** - Suppose a lightning strike on an AC Circuit that should have cleared normally becomes a Sustained Outage because of breaker failure. “Lightning” is the Initiating Cause Code and “Failed AC Substation Equipment” is the Sustained Cause Code.
- **Example 2** - Wind causes galloping on a conductor resulting in a circuit lockout. Several hours pass before the circuit can be patrolled to determine whether there was any damage. After patrolling, no damage was found, and the circuit was successfully re-energized. “Weather, excluding lightning” is the Initiating Cause Code as well as the Sustained Cause Code.
- **Example 3** - A Tornado passes through and fails a wood pole structure bringing it to the ground. The line is outaged for 57 hours before it can be returned to an in-service state. Weather, excluding lightning, is the initiating cause code and Failed AC Circuit Equipment is the Sustained Cause Code.

How to interpret “contributed to the longest duration”

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

longest duration. However, if the circuit breaker was repaired before the conductor, then “Failed AC Circuit Equipment” is the Sustained Cause Code.

Automatic Outage Cause Codes

The Automatic Outage Cause Code describes the cause with respect to location on the power system it occurred. (See Outage Initiation Code for location on the power system)

Weather, excluding lightning

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

Lightning

Automatic Outages caused by lightning.

Environmental

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

Contamination

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

Foreign Interference

Automatic Outages caused by foreign interference from such objects including 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 when falling conductors from another line cause a fault and result in an outage.

Foreign Interference is not due to an error by a utility employee or contractor. Categorize these as “Human Error.”

Fire

Automatic Outages caused by fire or smoke.

Physical Security Incident¹¹

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

Accidental acts initiated by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner should still be cause coded as “Human Error”.

Cyber Security Incident

A malicious act that causes an outage on a TADS reportable Element by disrupting the operation of a cyber-system. This includes incidents such as security perimeters being compromised through electronic means.

Failed AC Substation Equipment

Automatic Outages caused by the failure of AC Substation, i.e., equipment “inside the substation fence” including Transformers and circuit breakers but not Protection System equipment as it is not part of the AC Substation. Refer to the definition of “AC Substation.”

¹¹ This was previously known as Vandalism, Terrorism or Malicious Acts. It was changed to Physical Security Incident starting with 2024 reporting year to separate outages caused by a Cyber Security Incident.

For TADS reporting when an instrument transformer failure results in a BES fault on the primary system it should be reported as failed AC substation equipment.

Failed AC/DC Terminal Equipment

Automatic Outages caused by the failure of AC/DC Terminal equipment, i.e., equipment “inside the terminal fence” including PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors, and DC filters but not Protection System equipment as it is not part of the DC Terminal. Refer to the definition of “AC/DC Terminal.”

Failed Protection System Equipment

Automatic Outages caused by the failure of devices which are part of a Protection system as defined in the NERC Glossary of Terms. Includes any relay and/or control misoperations, *except* those that are caused by incorrect relay or control settings that do not coordinate with other protective devices. Categorize these as “Human Error”.

Automatic Outages caused by the failure of a protective device which is not part of the NERC defined Protection system should be coded as Failed AC Substation Equipment and NOT Failed Protection System Equipment.

For TADS reporting when an instrument transformer has a failure on the secondary system it should be reported as failed protection system equipment.

Failed AC Circuit Equipment

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

Failed DC Circuit Equipment

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

Vegetation

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

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

Outages that fall under the exclusions should be reported under another Cause Code and not the Vegetation Cause Code. Instances where the Initiating Cause Code is not Vegetation, the Sustained Cause Code would also not be Vegetation.

Vegetation outages reported under FAC-003-X would be expected to be reported with the Vegetation Cause Code in TADS.

Power System Condition

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

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. In addition, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported in this category.

Unknown

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

Other

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

Operational Outage Cause Codes**Emergency**

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

System Voltage Limit Mitigation

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

System Operating Limit Mitigation, excluding System Voltage Limit Mitigation

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

System Operating Limit:

The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

1. Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
2. Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
3. Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
4. System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits).

Do not include actions in the last category (System Voltage Limits) since this is included in the previous “System Voltage Limitation” code.

Human Error

Use for manual switching errors and any operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities.

- **Example 1** - An employee intends to open breaker 1 to outage circuit A. However, he operates the wrong control handle and opens breaker 3 and outages circuit B.
- **Example 2** - An employee is testing a relay and, as a result, unintentionally operates a breaker, placing the circuit into a not In-Service State. This would also include interruptions when an electrician is working in the switchhouse and accidentally shorts out a circuit and trips a breaker.

Other Operational Outage

Use for Operational Outages for reasons not included in the above list.

Appendix B: Inventory Data Calculation and Entry

The following examples demonstrate a calculation method that can be used to complete the TADS inventory spreadsheet data for detailed inventory reporting and summary Multi-Circuit Structure Mile reporting. Also, these methods are applicable in calculating Equivalent: DC Circuit Mileage, Number of DC Circuits, Number of Transformers and Number of AC/DC Back to Back Converters. Conceptually, equivalent measurements are defined as the measure multiplied by the percent of the year that the Element was able to be in an In-Service State.

The TADS Working Group acknowledges that other calculation methods can be utilized to complete the inventory spreadsheet. Every reporting Entity must determine the method that is best for their organization.

Equivalent Circuit Mileage

Conceptually, equivalent measurements are defined as the measure multiplied by the percent of the year that the Element was able to be in an In-Service State. For Circuit Mileage, this is defined as:

$$\text{Equivalent Circuit Mileage} = \text{Element Circuit Mileage} \times \frac{\text{Days In Service} + \text{Days in Outage}}{\text{Total Days in Reporting Year}}$$

For example, a 5-mile circuit commissioned on midnight March 1 with no outages would have $5.0 \text{ Circuits} \times (306.00 + 0.00)/365.00 \approx 4.19$ Equivalent AC Circuit Miles for the entire year. DC Circuit Elements are calculated similarly. To increase accuracy, fractional days may be used to take into account the circuit commissioning time. If taking into account the fractional days from the beginning of a reporting year, count from January 1 at 00:00:01 UTC for the beginning of the year. For the end of the year, count to December 31 at 23:59:59 UTC.

Equivalent Number of Elements

Conceptually, equivalent measurements are defined as the measure multiplied by the percent of the year that the Element was able to be in an In-Service State. For Number of Elements, this is defined as:

$$\text{Equivalent Number of Elements} = \text{Element Number of Elements} \times \frac{\text{Days In Service} + \text{Days in Outage}}{\text{Total Days in Reporting Year}}$$

For example, a circuit commissioned on midnight March 1 with no outages would have $1.0 \text{ Circuits} \times (306.00 + 0.00)/365.00 \approx 0.84$ Equivalent AC Circuits for the entire year. A similar calculation is performed for DC Circuit Elements.

To increase accuracy, fractional days may be used to take into account the circuit commissioning time. If you are using the fractional days from the beginning of a reporting year, the count would begin on January 1 at 00:00:01 UTC. For the end of the year, count to December 31 at 23:59:59 UTC.

Inventory Data Entry Examples

In [Figure B.1](#) below, System A needs to be reported in webTADS. The entire system is 345 kV, and it consists of multiple AC Circuits added and removed throughout the year. It is assumed that all of the original circuits were placed in-service on January 1, 2013. Also, a temporary substation is added and then removed in order to perform maintenance on circuit DF1 during the year. This will need to be accounted for in the detailed inventory as it changes both Element identifiers and mileages.

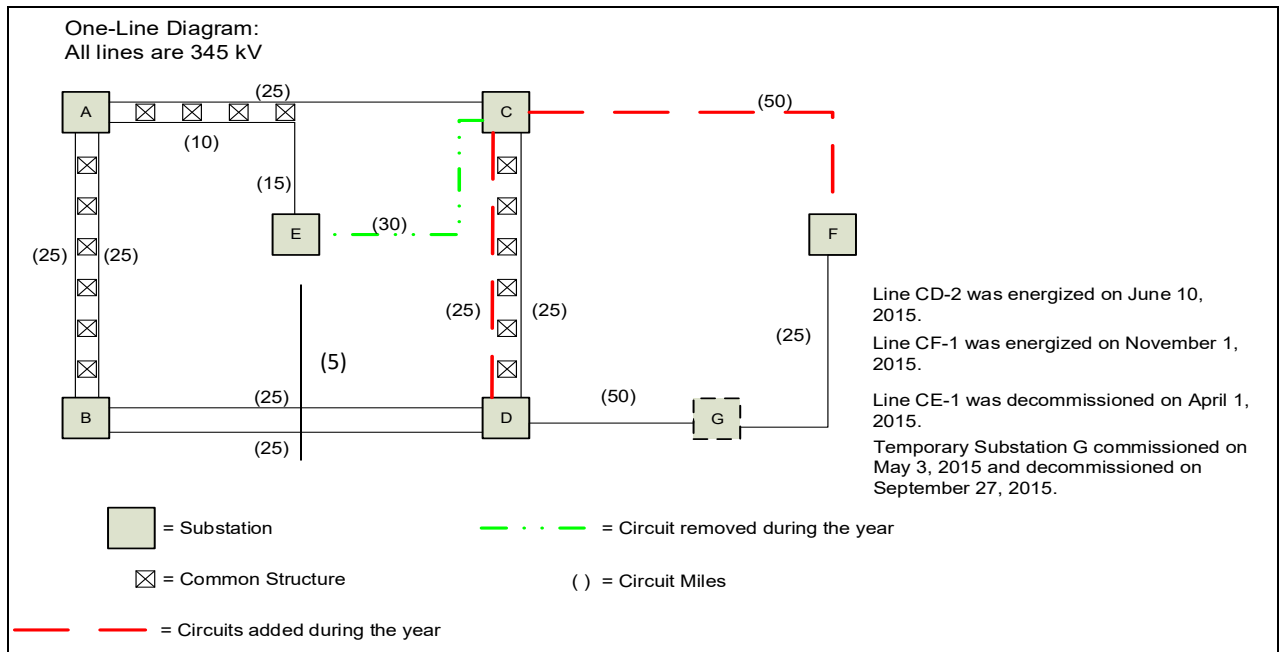


Figure B.1: System A One-line Diagram

As System A contains only AC Circuits, the inventory will be entered into TADS using Form 3.1 [Table B.1](#) below shows the required data fields which must be provided to enter the example system into the TOs inventory data.

Table B.1: Form 3.1 Detailed AC & DC Ckt Inventory Data

Unique Element Identifier	Voltage Class	Circuit Miles	Number of Terminals	Change / Reconfiguration Date	Retirement Date	Precursor Element	From Bus	To Bus	Tertiary Bus
AB1	300-399 kV	25	2	1/1/2013			A	B	
AB2	300-399 kV	25	2	1/1/2013			A	B	
AE1	300-399 kV	25	2	1/1/2013			A	E	
AC1	300-399 kV	25	2	1/1/2013			A	C	
BDE1	300-399 kV	30	3	1/1/2013			B	D	E
BD2	300-399 kV	25	2	1/1/2013			B	D	
CD1	300-399 kV	25	2	1/1/2013			C	D	
CE1	300-399 kV	30	2	1/1/2013			C	E	
DF1	300-399 kV	75	2	1/1/2013			D	F	

Adding and Splitting Circuits

On 5/3/2015, temporary substation G is commissioned which splits line DF1 into DG1 and FG1. This is followed by circuit CD2 going in-service on 6/10/2015.

A new entry is added to Form 3.1 to account for circuit CD2. Then the entry for circuit DF1 is modified to indicate a Retirement Date of 5/3/2015 to account for the temporary substation G. Finally, two additional entries are made to include the new circuits DG1 and FG1. The Precursor Element field is populated for the two new circuits to indicate they were the result of splitting a previous line. These changes are shown in [Table B.2](#) below.

Table B.2: Form 3.1 Detailed AC & DC Ckt Inventory Data

Unique Element Identifier	Voltage Class	Circuit Miles	Number of Terminals	Change / Reconfiguration Date	Retirement Date	Precursor Element	From Bus	To Bus	Tertiary Bus
CD2	300-399 kV	25	2	6/10/2015			C	D	
DF1	300-399 kV	75	2	1/1/2013	5/3/2015		D	F	
DG1	300-399 kV	50	2	5/3/2015		DF1	D	G	
FG1	300-399 kV	25	2	5/3/2015		DF1	F	G	

Deleting a Substation

On 7/19/2015, temporary substation G is removed. This results in circuits DG1 and FG1 combining back onto one continuous circuit. In order to maintain the change history, this circuit must be given a new Element Identifier and it cannot be the same ID which was used before temporary substation G was commissioned. In [Table B.3](#) below, Form 3.1 is modified to add a Retirement Date of 7/19/2015 for circuit DG1 and FG1. The combined circuit DF1_2 is added and the Precursor Element field is populated with the previous line segments which now make up the new circuit.

Table B.3: Quarter 1 2015 Form 3.1 TADS Inventory Entry

Unique Element Identifier	Voltage Class	Circuit Miles	Number of Terminals	Change / Reconfiguration Date	Retirement Date	Precursor Element	From Bus	To Bus	Tertiary Bus
DG1	300-399 kV	50	2	5/3/2015	7/19/2015	DF1	D	G	
FG1	300-399 kV	25	2	5/3/2015	7/19/2015	DF1	F	G	
DF1_2	300-399 kV	75	2	7/19/2015		DG1, G1	D	F	

AC Multi-Circuit Structure Miles Calculation Example - Form 3.5

As shown in [Table B.4](#) below, 85 would be entered into the column titled “Multi-Circuit Structure Miles (End of Year)” for System A.

Table B.4: Form 3.5 Multi-Circuit Structure Miles Calculations (Elements at the end of the year)

Element Identification	Multi-Circuit Structure Miles
AB1 and AB2	25
AC1 and AE1	10
CD1 and CD2	25
BDE1 and BD2	25
Total Structure Miles	85

For System A, 25 would be entered into the column titled “No. of Multi-Circuit Structure Miles for Circuits Added”.

For System A, 14.04 would be entered into the column titled “Equivalent Annual No. of Multi-Circuit Structure Miles for Circuits Added”.

Table B.5: Multi-Circuit Structure Miles Calculations (Elements added during the year)			
Element Identification	Multi-Circuit Structure Miles	Number of Days from In-Service date to the end of the reporting year	Equivalent Multi-Circuit Structure Miles
CD1 and CD2	25	205	14.04
Total Equivalent Structure Miles added during the year			14.04

- 25 Structure Miles (205 days in service during the year/365 days in year) = 14.04

A similar calculation would be performed for Multi-Circuit Structure Miles for Circuits Removed during a reporting year.

TADS Element on a common structure with a non-BES Element

In this situation, AC Circuit CF was placed on a common structure with an existing non-BES, 69 kV circuit. For TADS, this common structure situation shall not be included in the Multi-Circuit Structure Mile calculation. For TADS, you are only to report those Multi-Circuit Structure Miles where two or more TADS Elements share a common structure. Non-BES Elements are not considered TADS Elements.

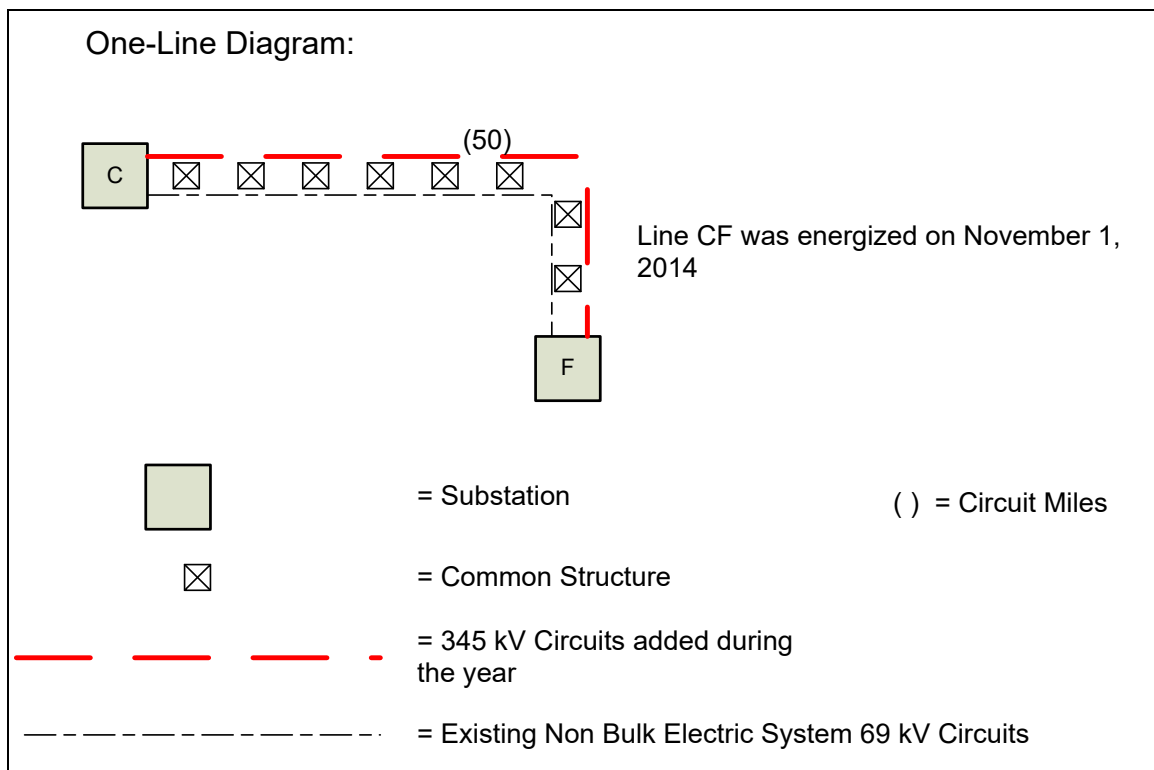


Figure B.1: Example B One-line Diagram

Appendix C: Detailed Automatic Outage Data Examples

The following examples illustrate several AC Circuit Automatic Outage scenarios accompanied by (in most cases) a Transformer Automatic Outage scenario. Data entries for Form 4.1, Form 4.2 and Form 5.0 with the appropriate data entries for the reportable outages are provided. While not all possible situations could be covered, the examples are complete enough to help with outage interpretation.

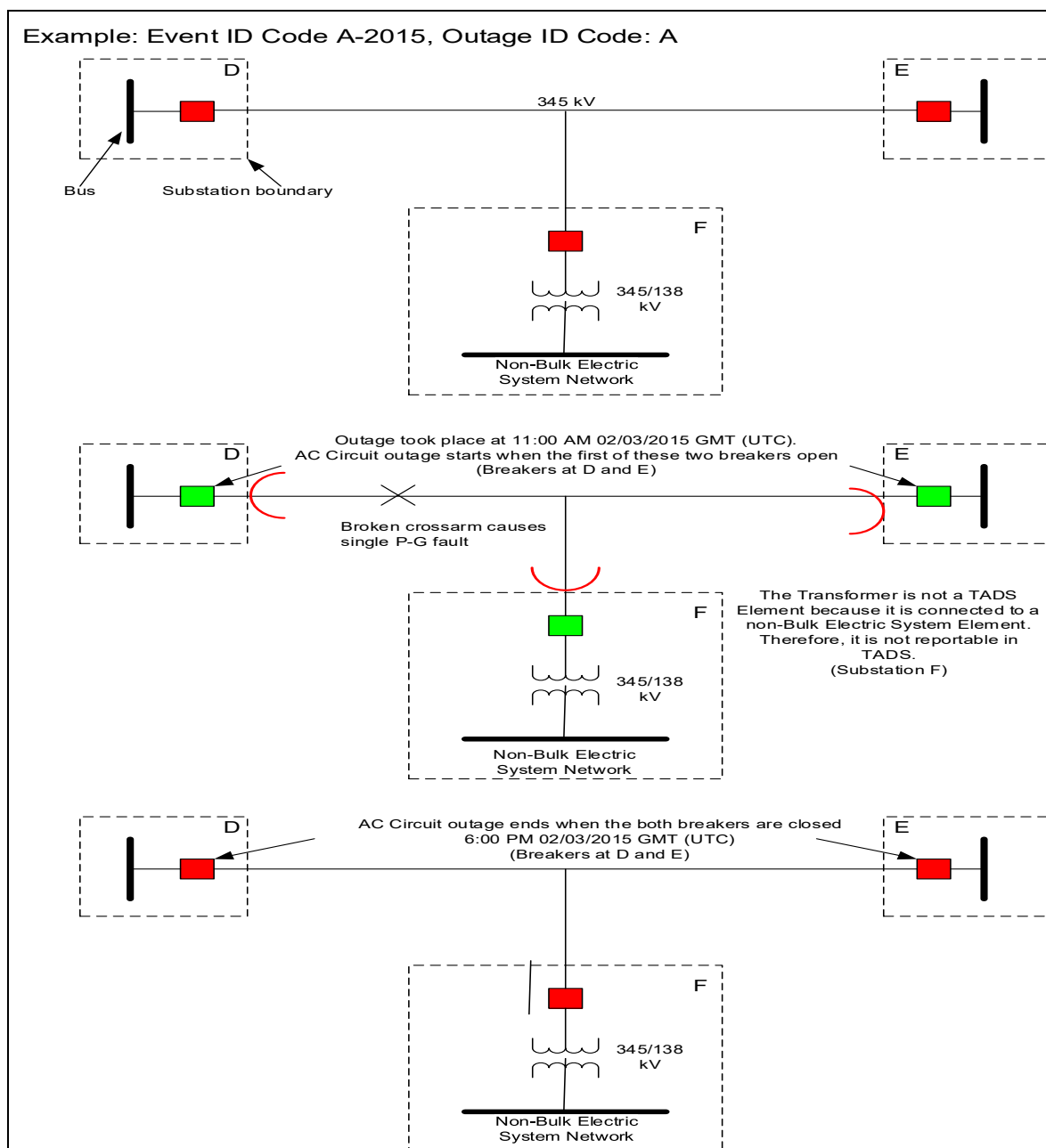


Figure C.1: Example 1 AC Circuit with Non-TADS Transformer

In Figure C.1, an AC Circuit with a non-TADS Element attached to one of the segments is shown. Since the transformer is not considered a TADS Element, outages to the transformer are not reportable.

It is important to note in this example the application of the TADS In-Service State definition. There is only one exception, the multi-terminal transformer exception, that an Element be “connected at all its terminals” to be considered in an In-Service State. This exception applies only to a multi-terminal AC Circuit with a transformer on one terminal sharing a breaker with the circuit.

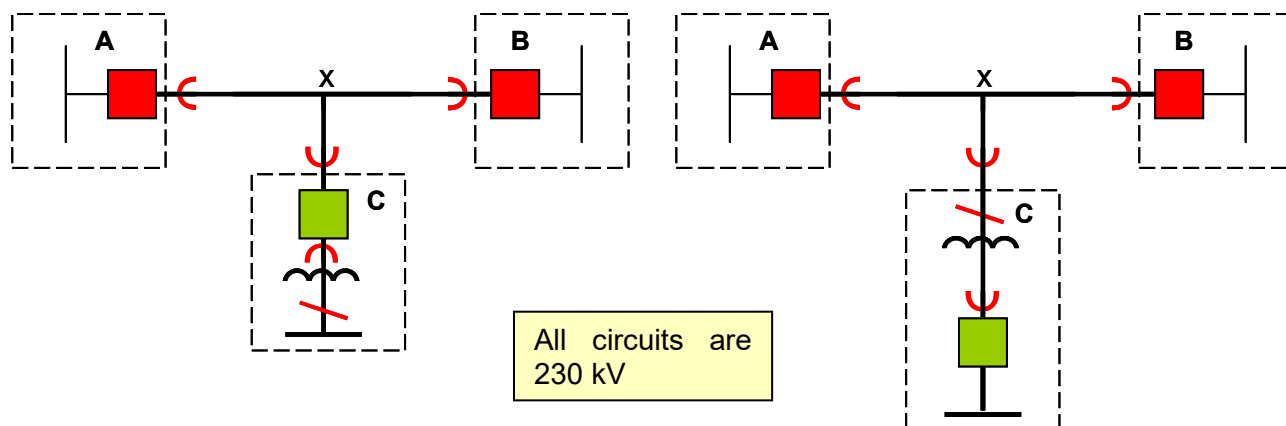


Figure C.2

Figure C.1

In [Figure C.2](#) and [Figure C.3](#), the AC Circuit is bounded by AC Substations A, B, and C as indicated by the red arcs. Each transformer’s boundaries are the red disconnect switch and the red arc before the breaker. Note, the transformer in either figure may *or* may not be a reportable Element.

Assume that each transformer is out of service because of the operation of its associated breaker (indicated in green). In [Figure C.2](#), the AC Circuit would normally be considered out of service since the breaker at AC Substation C, which is shared by the AC Circuit and the transformer, is open. Nevertheless, if all other portions of the AC Circuit are in service, the entire AC Circuit is considered to be in an In-Service State even if the transformer is out of service. Because TADS does not recognize partial outage states, the multi-terminal exception above was developed. This avoids overstating the outage contribution of this multi-terminal configuration type. In [Figure C.23](#), the open breaker is not shared by the AC Circuit, and the AC Circuit remains connected. Thus, the exception does not apply, in this case, since the AC Circuit is connected at all its terminals even though the transformer is out of service. This outage will require the completion of Form 5.0 and 4.1. Data entries for these forms are shown below in [Table C.1-Table C.2](#).

Table C.1: Example 1 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
A-2015	11		No

Table C.2: Example 1 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
A	Single P-G Fault	Element-Initiated	2/3/208 11:00	7:00	Failed AC Circuit Equipment	Failed AC Circuit Equipment	Single Mode	0

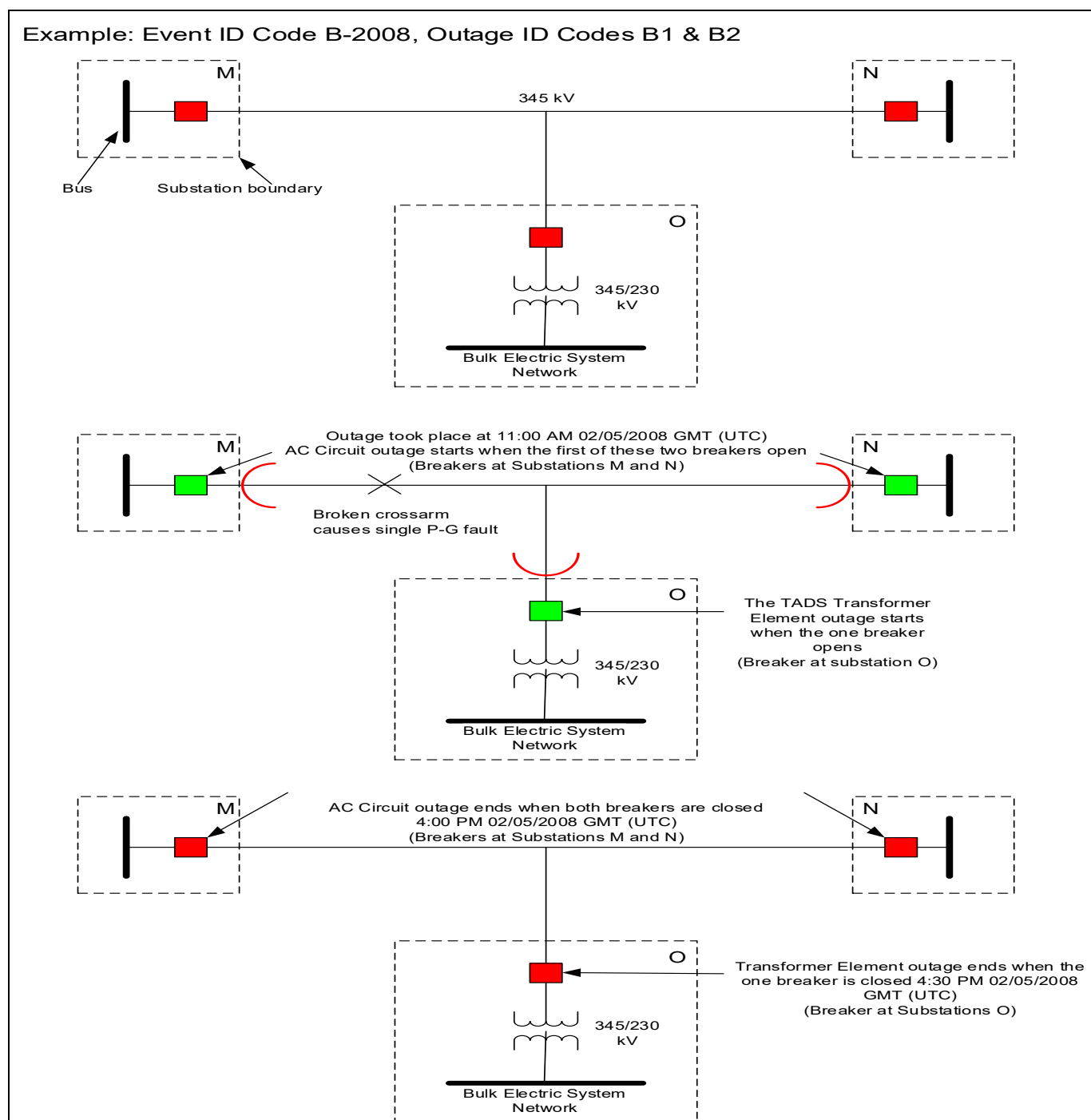


Figure C.2: Example 2 Three-terminal AC Circuit with a TADS Transformer

This is a three-terminal, AC Circuit with a TADS Transformer attached to one of the segments. Since the Transformer is a TADS Element, its outage is reportable. This outage will require the completion of Form 5.0, 4.1, and 4.3. Data entries for these forms are shown below in [Table C.3-Table C.5](#).

Table C.3: Example 2 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
B-2008	13	Outage of 345 kV Transmission Line and 345 kV/230 kV Transformer	No

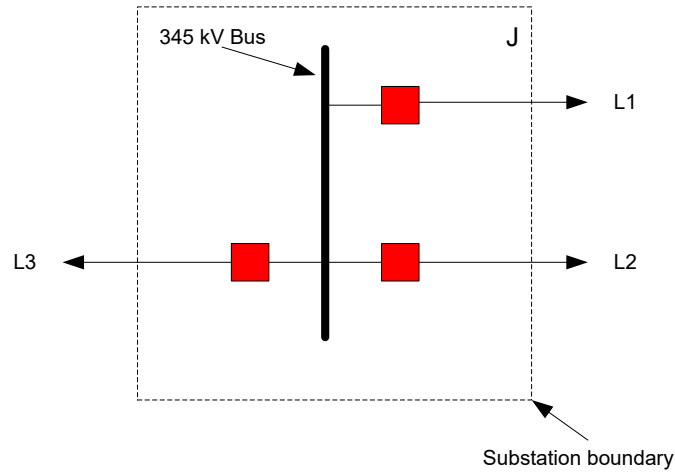
Table C.4: Example 2 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
B1	Single P-G Fault	Element-Initiated	2/3/2008 11:00	5:00	Failed AC Circuit Equipment	Failed AC Circuit Equipment	Dependent Mode Initiating	0

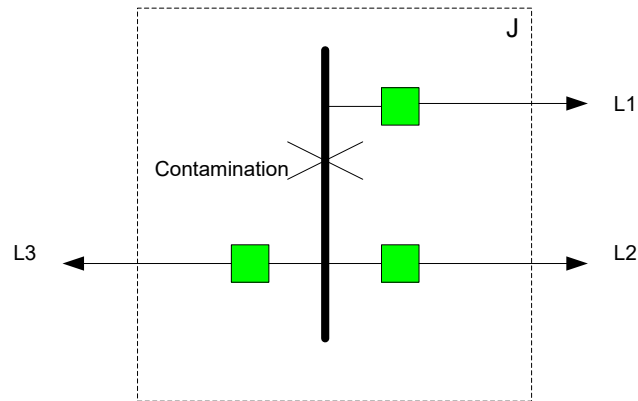
Table C.5: Example 2 Form 4.3 - Transformer Detailed Automatic Outage Data

Outage ID Code	Event ID Code	High-Side Voltage Class	Fault Type	Outage Initiating Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
B2	B-2008	300-399 kV	No fault	Other Element-Initiated	2/5/2008 11:00	5:30	Failed AC Circuit Equipment	Failed AC Circuit Equipment	Dependent Mode	0

Example: Event ID Code C-2008, Outage ID Codes, C1, C2 and C3



Single P-G fault on the Bus at 6:00 PM 4/29/2008 GMT (UTC)



Individual outages are over when corresponding line breakers are placed in-service
 Breakers for L1 and L2 were closed at 6:20 PM 04/29/2008 GMT (UTC)
 Breaker for L3 was closed at 7:00 PM 4/29/2008 GMT (UTC)

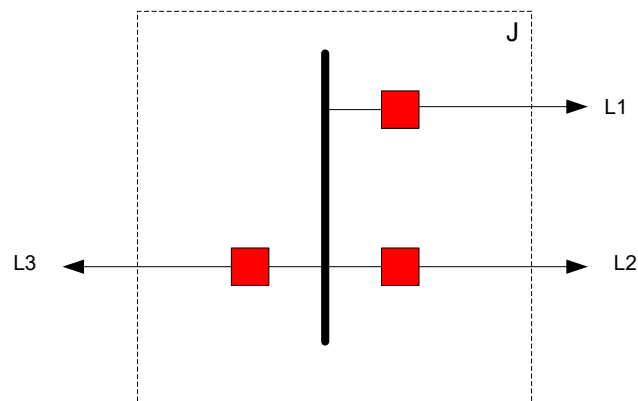


Figure C.3: Example 3: Bus Fault Interrupts TADS Elements

This is an outage of a 345 kV bus caused by contamination. No damage resulted, and all the AC Circuits connected to the bus are reportable. This outage will require the completion of Form 5.0 and 4.1. Data entries for these forms are shown below in [Table C.6-Table C.7](#).

Table C.6: Example 3 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
C-2008	05	Bus Outage	No

Table C.7: Example 3 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
C1	Single P-G Fault	AC Substation-Initiated	4/29/2008 18:00	0:20	Contamination	Contamination	Common Mode	0
C2	Single P-G Fault	AC Substation-Initiated	4/29/2008 18:00	0:20	Contamination	Contamination	Common Mode	0
C3	Single P-G Fault	AC Substation-Initiated	4/29/2008 18:00	1:00	Contamination	Contamination	Common Mode	0

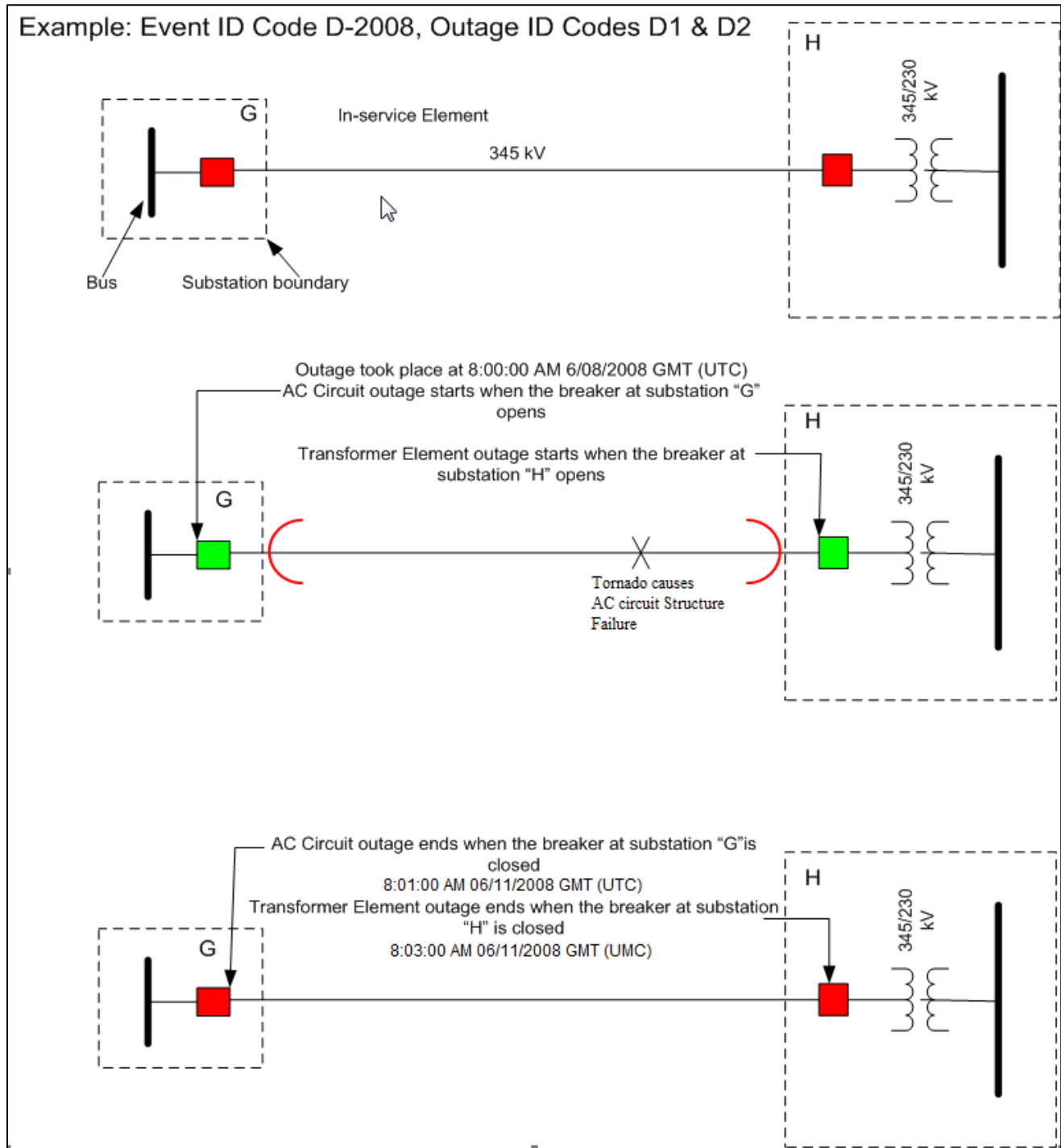


Figure C.4: Example 4 AC Circuit directly connected to a TADS Transformer

The AC Circuit structure was damaged by the tornado and required replacement. This outage will require the completion of Form 5.0, 4.1, and 4.3. Data entries for these forms are shown below in [Table C.8-Table C.10](#).

Table C.8: Example 4 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
D-2008	13	Outage of 345 kV Transmission Line and 345 kV/230 kV Transformer	No

Table C.9: Example 4 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
D1	Element-Initiated	AC Substation-Initiated	6/8/2008 8:00	3:00	Weather, excluding lightning	Failed AC Circuit Equipment	Dependent Mode Initiating	0

Table C.10: Example 4 Form 4.3 - Transformer Detailed Automatic Outage Data

Outage ID Code	Event ID Code	High-Side Voltage Class	Fault Type	Outage Initiating Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
D2	D-2008	300-399 kV	No fault	Other Element-Initiated	6/8/2008 8:00	3:00	Weather, excluding lightning	Failed AC Circuit Equipment	Dependent Mode	0

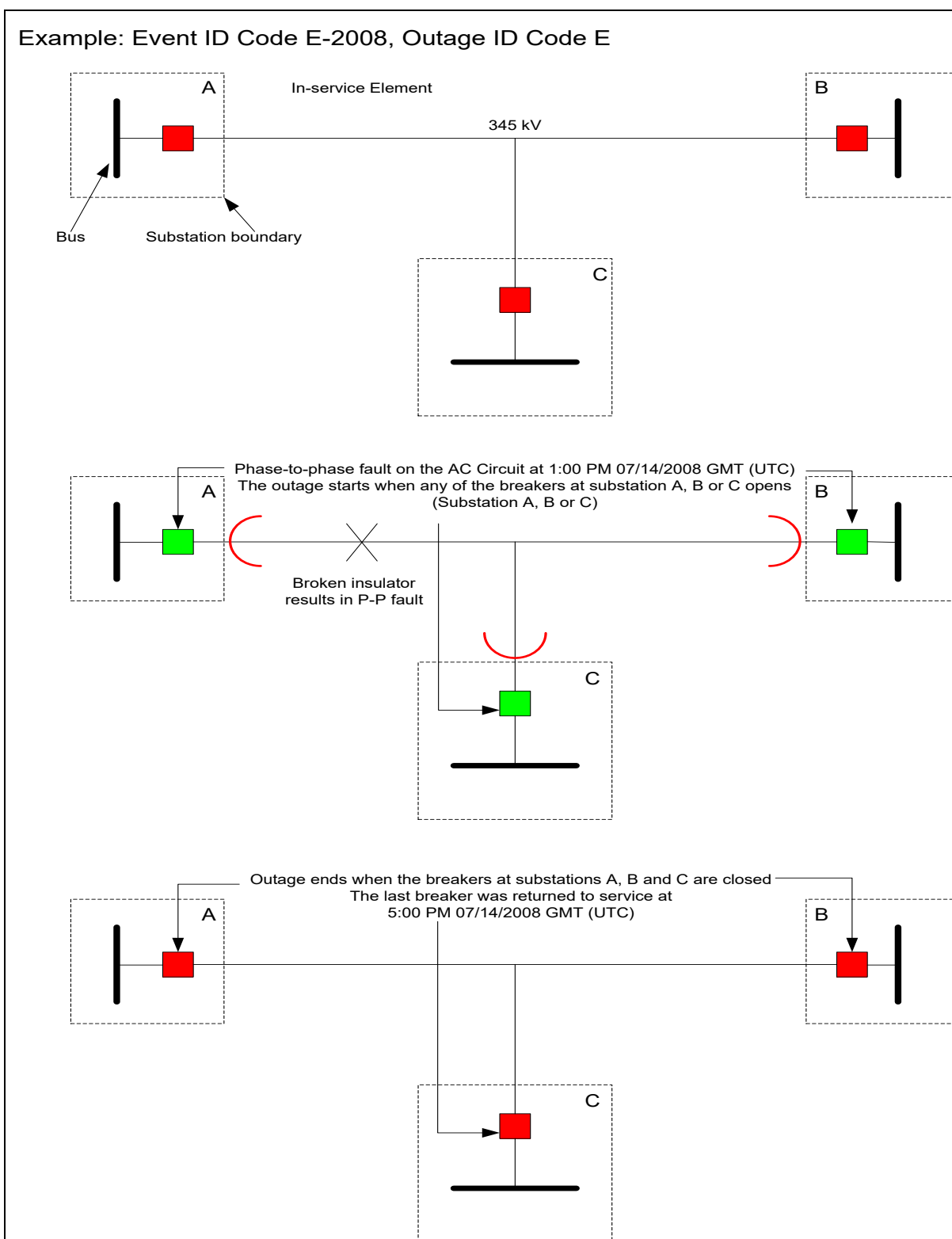


Figure C.5: Example 5 Three-terminal AC Circuit

This outage will require the completion of Form 5.0 and 4.1. Data entries for these forms are shown below in [Table C.11-Table C.12](#).

Table C.11: Example 5 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
E-2008	11		No

Table C.12: Example 5 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
E	P-P fault	Element-Initiated	7/14/2008 13:00	4:00	Failed AC Circuit Equipment	Failed AC Circuit Equipment	Single Mode	0

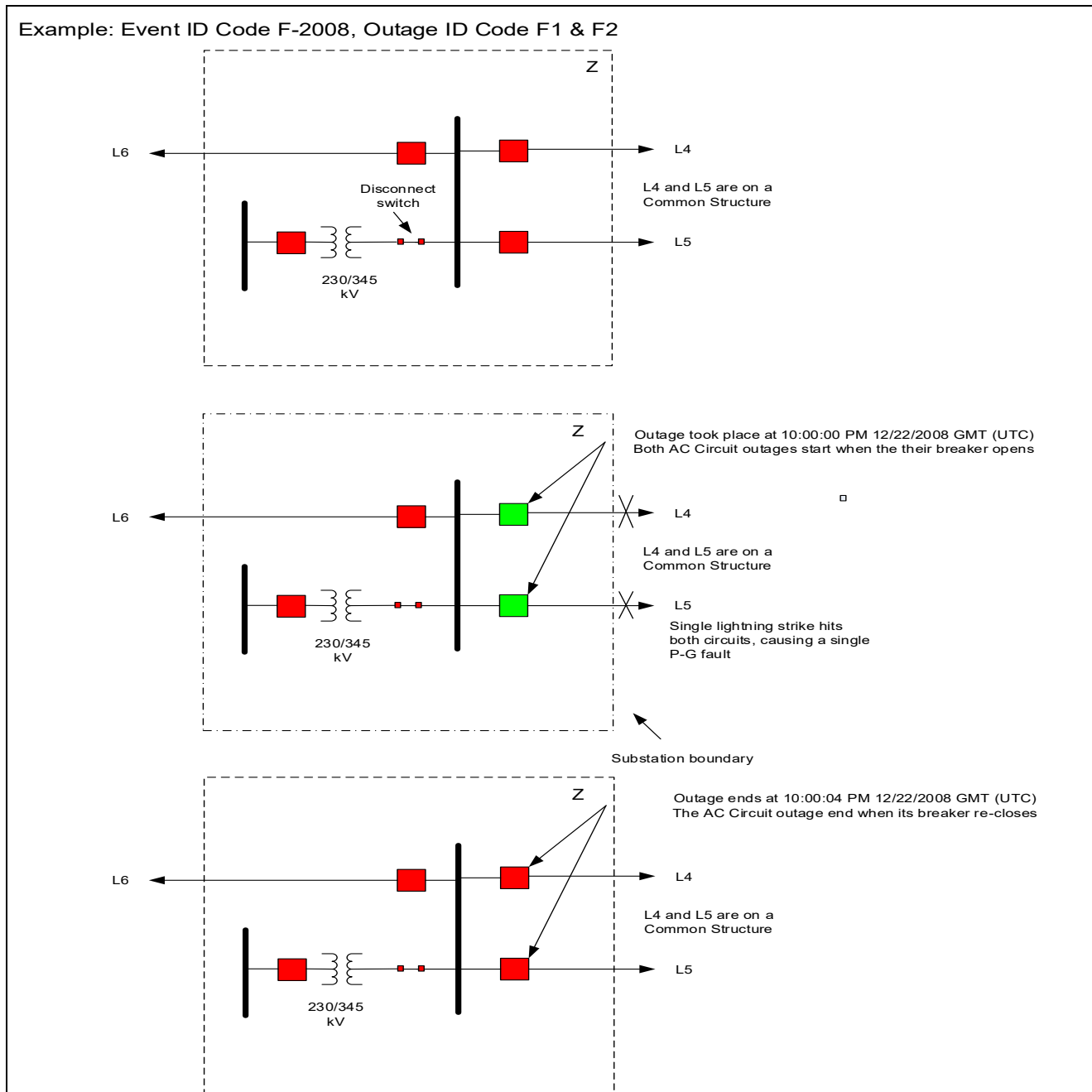


Figure C.6: Example 6: Outage of two AC Circuits with Common Cause

This outage will require the completion of Form 5.0 and 4.1. Data entries for these forms are shown below in [Table C.13-Table C.14](#).

Table C.13: Example 6 Form 5.0 - Event ID Code Data			
Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
F-2008	31		No

Table C.14: Example 6 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
F1	Single P-G fault	Element-Initiated	12/22/2008 13:00	0:00	Lightning	NA-Momentary	Common Mode	0
F2	Single P-G fault	Element-Initiated	12/22/2008 22:00	0:00	Lightning	NA-Momentary	Common Mode	0

Note: The outages would have been characterized as a Common Mode Outage even if the AC Circuits had not been on common structures.

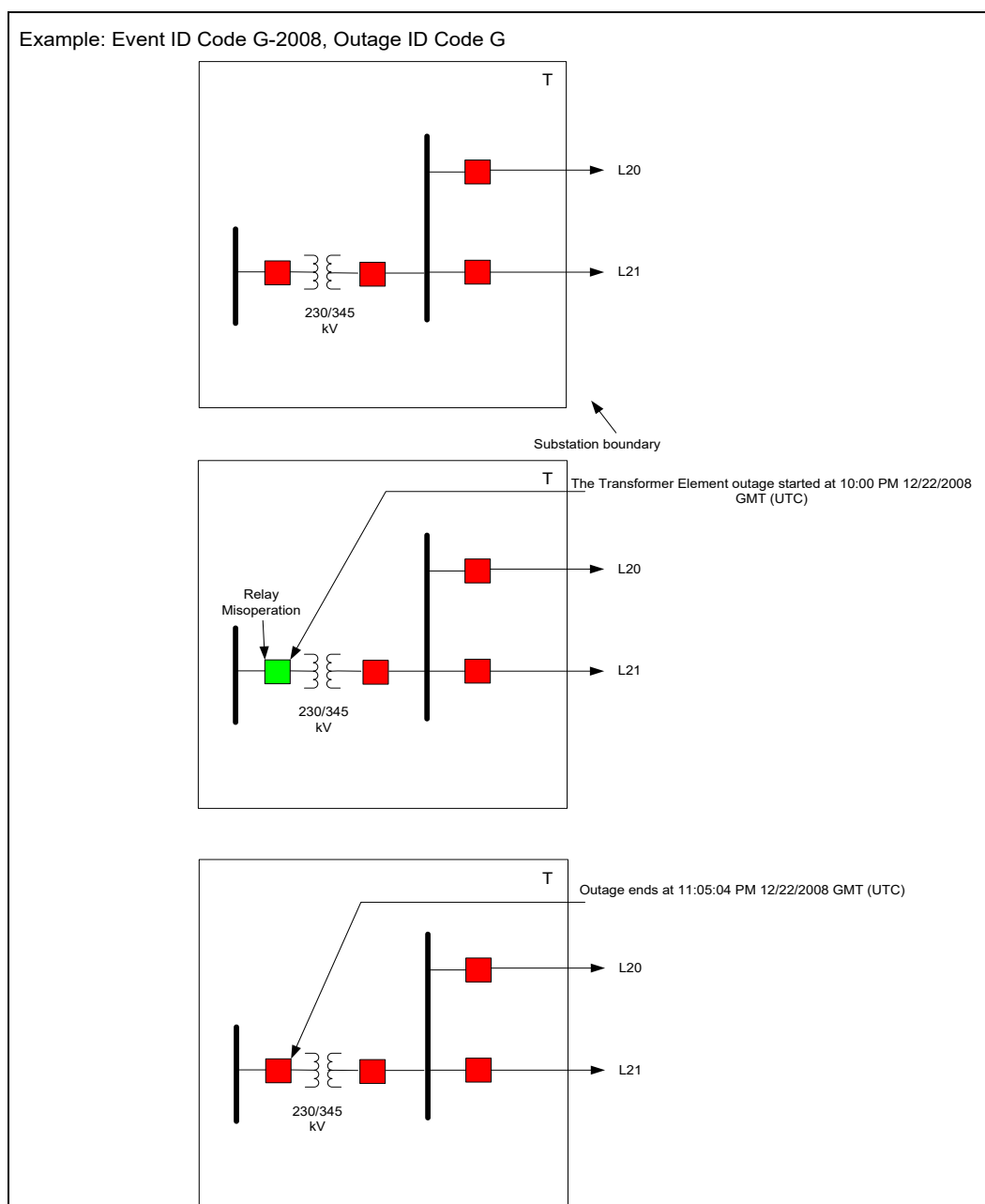


Figure C.7 Example 7: Transformer Outage with Protection System Misoperation

Only the Transformer was outaged because of the relay misoperation. This outage will require the completion of Form 5.0 and 4.3. Data entries for these forms are shown below in [Table C.15-Table C.16](#).

Table C.15: Example 7 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
G-2008	11		No

Table C.16: Example 7 Form 4.3 - Transformer Detailed Automatic Outage Data

Outage ID Code	Event ID Code	High-Side Voltage Class	Fault Type	Outage Initiating Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
G	G-2008	300-399 kV	No fault	Other Element-Initiated	12/22/2008 22:00	1:05	Failed Protection System Equipment	Failed Protection System Equipment	Single Mode	0

Example: Event ID Code H-2008, Outage ID Code H1, H2 & H3

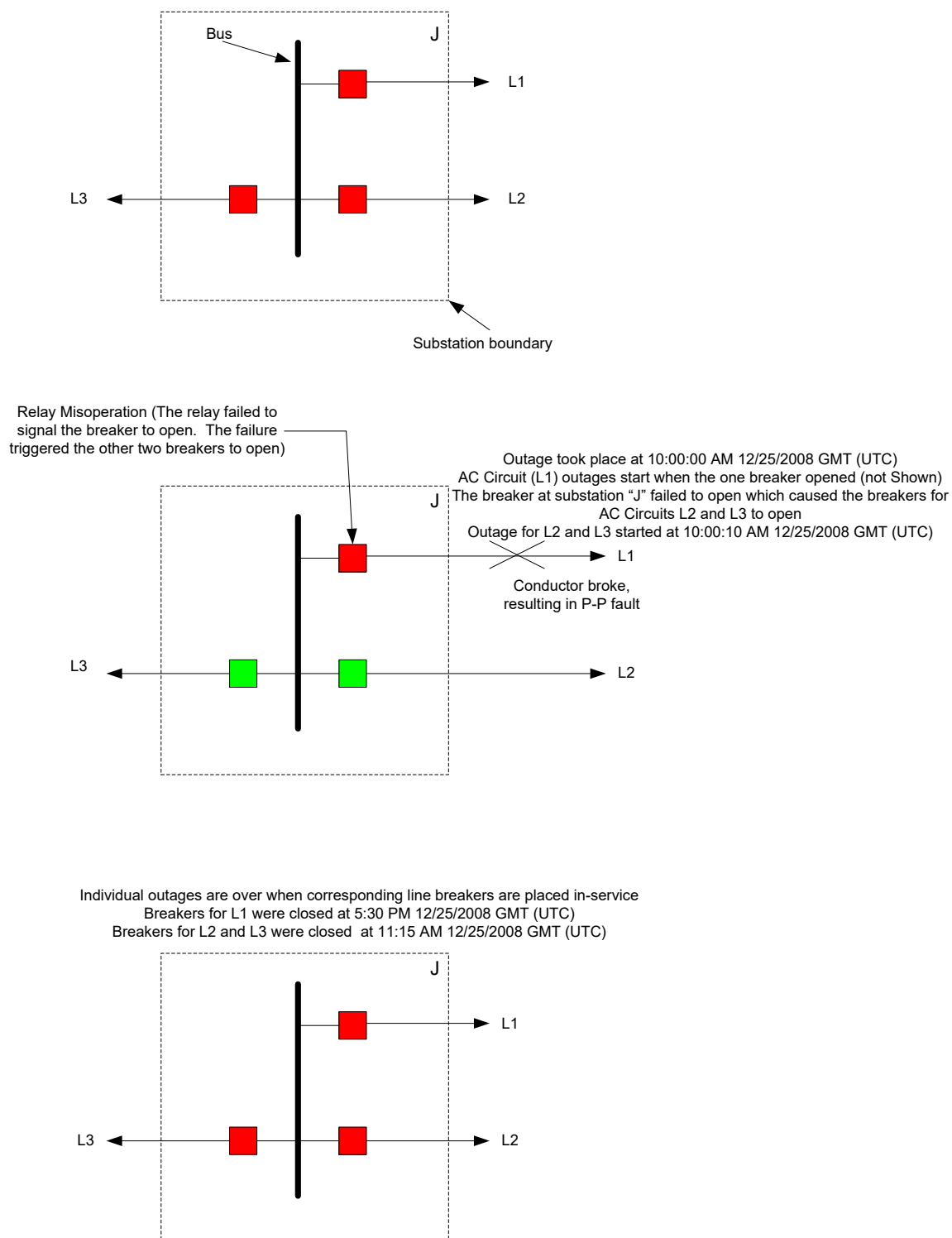


Figure C.8: Example 8: AC Circuit Outage with Breaker Failure

This outage will require the completion of Form 5.0 and 4.1. Data entries for these forms are shown below in [Table C.17-Table C.18](#).

Table C.17: Example 8 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
H-2008	60	Fault on an AC Circuit and a circuit breaker equipment failure resulting in a stuck circuit breaker	No

Table C.18: Example 8 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
H1	P-P fault	Element-Initiated	12/25/2008 10:00	7:30	Failed AC-Circuit Equipment	Failed AC-Circuit Equipment	Dependent Mode Initiating	0
H2	P-P fault	Other Element-Initiated	12/25/2008 10:00	1:15	Failed Protection System Equipment	Failed Protection System Equipment	Dependent Mode	0
H3	P-P fault	Other Element-Initiated	12/25/2008 10:00	1:15	Failed Protection System Equipment	Failed Protection System Equipment	Dependent Mode	0

Example: Event ID Code K-2015, Outage ID Code K1 and K2

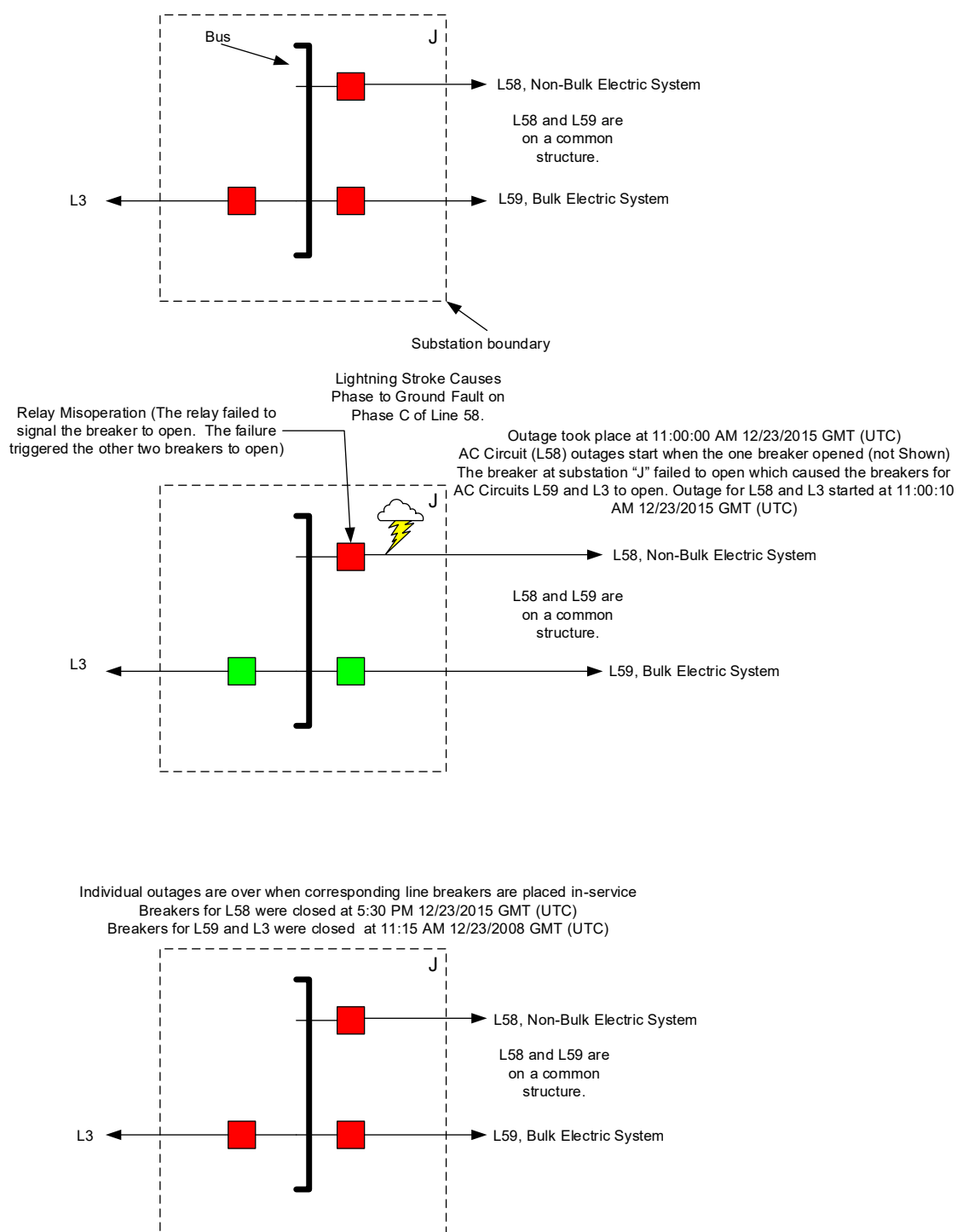


Figure C.9: Example 9: AC Multi-Circuit Structure Outage with Non-TADS Element on Structure

In Figure C.11, Example 9 shows an outage that will require the completion of Form 5.0s and 4.1. Data entries for these forms are shown below in [Table C.19-Table C.20](#).

Table C.19: Example 9 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
K-2015	61	Single phase to ground fault, relay does not signal circuit breaker on non-BES Line.	No

Table C.20: Example 9 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
K1	No Fault	Protection System-Initiated	12/23/2015 11:00	0:15	Failed Protection System Equipment	Failed Protection System Equipment	Dependent Mode	0
K2	No Fault	Protection System-Initiated	12/23/2015 11:00	0:15	Failed Protection System Equipment	Failed Protection System Equipment	Dependent Mode	0

Example: Event ID Code L-2015, Outage ID Code LL3_3, LL60 and LL61

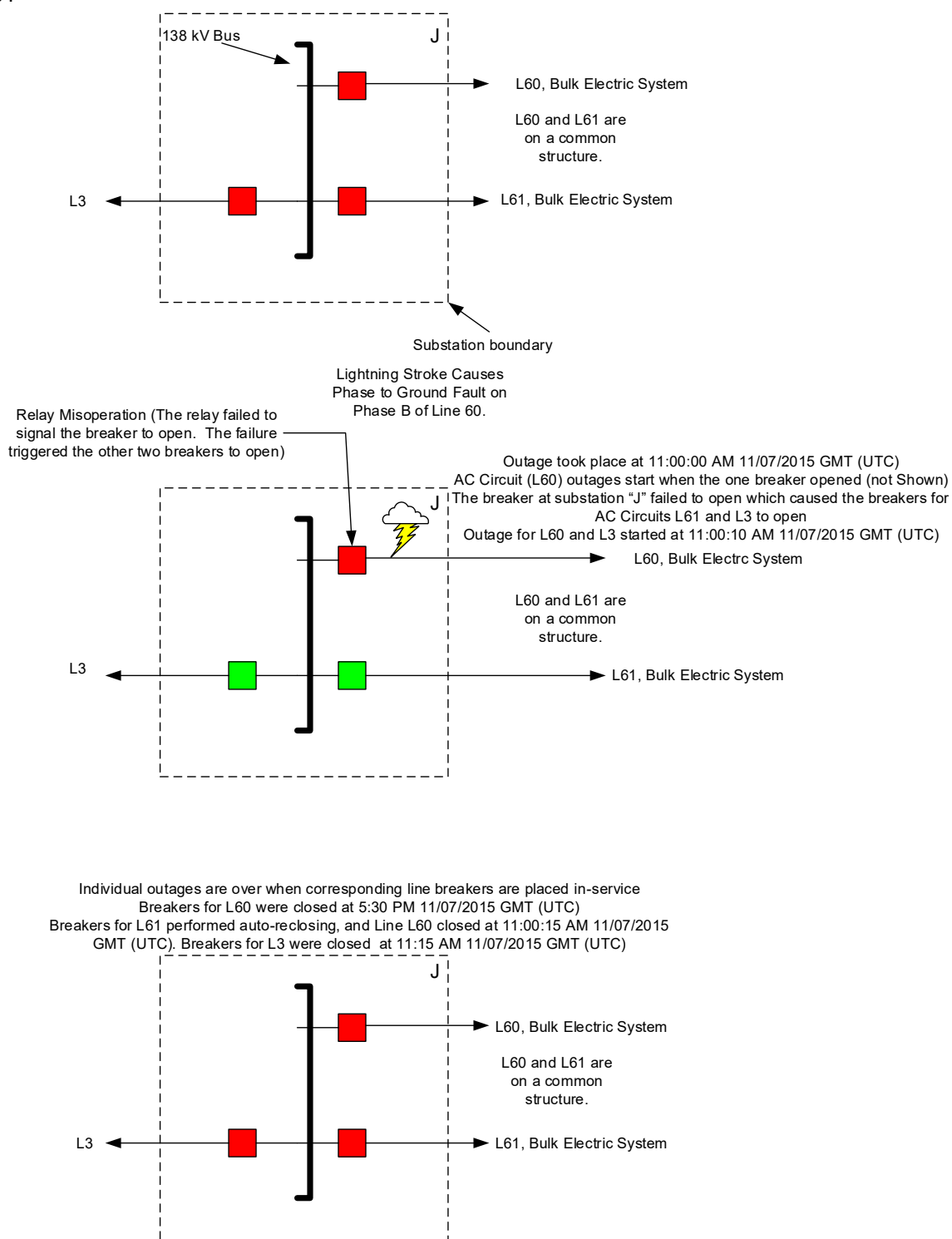


Figure C.10: Example 10: AC Multi-Circuit Structure Outage with TADS Element on Structure

The outage shown in Figure C.12, Example 10, will require the completion of Form 5.0 and 4.1. Data entries for these forms are shown below in [Table C.21-Table C.22](#).

Table C.21: Example 10 Form 5.0 - Event ID Code Data

Event ID Code	Event Type No.	Description of the Event (optional)	Disturbance Report Filed
L-2015	61	Single phase to ground fault, relay does not signal circuit breaker on BES Line	No

Table C.22: Example 10 Form 4.1 - AC Circuit Detailed Automatic Outage Data

Outage ID Code	Fault Type	Outage Initiation Code	Start Time	Outage Duration	Initiating Cause Code	Sustained Cause Code	Outage Mode	Outage Continuation Code
LL60	Lightning	Single P-G fault	11/07/2015 11:00	6:30	Lightning	Failed Protection System Equipment	Dependent Mode Initiating	0
LL61	No Fault	Protection System-Initiated	11/07/2015 11:00	0:15	Failed Protection System Equipment	Failed Protection System Equipment	Dependent Mode	0
LL3_3	No Fault	Protection System-Initiated	11/07/2015 11:00	0:15	Failed Protection System Equipment	Failed Protection System Equipment	Dependent Mode	0

Example 11: Animal Damage within Substation

A rat gains entry into a substation control house and chews on a control or relay cable. The relay either operates immediately or sometime in the future (or does not operate when called upon). Operation could be an unnecessary trip during a fault (on another Element) or an unnecessary trip in absence of a fault on the system. It could also result in failure of primary Element to trip for fault condition which could result in other Elements needing to trip to clear the fault.

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

The Automatic Outage Cause Code for this outage would be Failed Protection System.

Appendix D: Frequently Asked Questions

Inventory Related Questions

1. Are generator lead lines reportable to TADS?

Question: Are generator lead lines part of the BES? Are they reportable in TADS?

Answer: If the AC Circuit leads to a network source comprising more than 75 MW of generator capacity, the AC Circuit is considered part of the BES¹². From the high side to the GSU to the first interrupting device or set of interrupting devices is considered to be GSU leads and not reportable to TADS regardless of the length.

See Scenario A and B for reportable and non-reportable outage examples.

Scenario A - Generator Lead Line Reporting

All the substations and transmission lines in Scenario A are 345kV. There is a 10-mile line/connection to a wind farm. This is considered a generator lead line at Utility X. For reportable outages, should the line/connection between Substation B and the wind farm be reported in TADS? (Note: The wind farm trips offline due a SPS (Special Protection System) in place for faults between Substation A and Substation B.) If the Wind Farm is at a total combined capacity above 75 MW, the generator lead line is considered part of the BES and should be reported in TADS. The 10 miles line from Substation B to the wind farm is reportable; however, the leads from the GSU breakers to the GSU are not reportable. Elements highlighted in red are TADS reportable; elements in green are not TADS reportable.

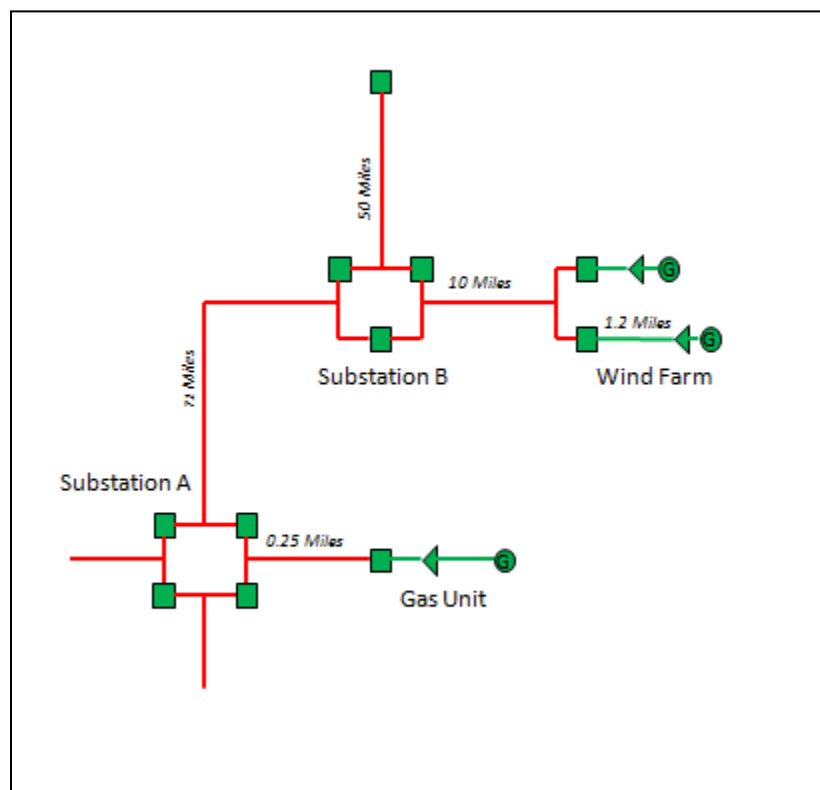


Figure D.1: Scenario A

¹² <http://www.nerc.com/pa/rapa/pages/bes.aspx>

Scenario B - Generator Lead Line Reporting

The gas unit plants sit adjacent to the 345kV substation. The gas units trip offline from time to time. In addition, they are taken offline for maintenance and load curtailment during the spring and fall seasons. Should Automatic and Planned outages on those lines be reported in TADS?

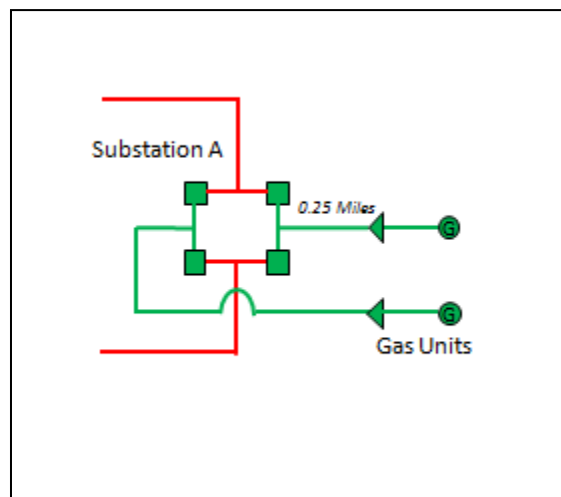


Figure D.2: Scenario B

Based on the configuration shown, no Outages would be reported to any elements if any one of the Gas Units are tripped offline with the normal clearing circuit breaker set. However, if both Gas Units are offline, this would result in a reportable outage to both 345kV lines. This is based on the definition of In-Service State that requires all terminals to be connected and energized. Elements highlighted in red are TADS reportable; elements in green are not TADS reportable.

2. DC line with only two circuits clarification

Question: In our network, we have a DC line with two sections per pole: X to Y (1000 km) and Y to Z (500 km), with several multi-terminal and two-terminal configurations.

How many DC Circuits do I report to TADS in the following scenario?

Answer: If you can control the terminals in such a way that the power flow goes from 0 to a maximal value, it should be treated as the equivalent to a circuit breaker for a DC Circuit. Then, treat the network similarly to an AC Circuit network with each DC Circuit having two poles. In this specific case, this network would be interpreted as 2 separate DC Circuits (X-Y and Y-Z).

3. FERC Order No. 785 – Generator Requirements at the Transmission Interface

Question: NERC cannot force a Generator Owner (GO) to register as a Transmission Owner (TO) to report the transmission interconnections to the power grid. How should these transmission elements be handled?

Answer: TADS is only applicable to Transmission Owners. If an Element is either partially or fully owned by an Entity with a Transmission Owner function, that Element should be reported in TADS. Only BES elements up to the GSU high side breaker(s) are reportable. GSU leads regardless of length are not reportable.

Outage Related Questions

1. Trees washed out during flooding, slid down hill, and contacted line. Is the cause Environmental or Vegetation?

Question: Trees washed out during flooding, slid down hill, and contacted line. Is the Initiating Cause Code Environmental or Vegetation?

Answer: The Initiating Cause Code would be Environmental due to the flood.

2. Momentary, then Less than 1 Minute Operational Outage

Question: We had a momentary outage on a transmission line (5th on that line that day) because of buzzard “pollution”. 50 seconds later, the dispatchers manually opened the line (Emergency Forced) and the line remained deenergized for a week. How should report these outages? One (automatic) or two (automatic and manual)?

Answer: The outage should be reported as a single Outage due to the buzzard “Pollution”. In this case, it would be one Automatic Outage. The AC Circuit must be energized and connected at all terminals for at least 1 minute to be considered back in an In-Service state. This clause avoids numerous entries of auto-reclosing Automatic Outages.

3. Operator closes the second end of the line back after more than one minute

Question: A line correctly trips, and correctly recloses from one end. The other end of the line is designed to not reclose. If the operator closes the second end of the line back after more than one minute, what is the “Sustained Code”? There is no damage to the line, and the operator did not make an error. In the past, I was advised that this would be the same as the Outage Initiating Code. Is this correct?

Answer: If one or more terminals are not designed to reclose or reclosing has been disabled for any condition, then the sustained cause code would be other.

4. How to code an outage when a circuit is out of service for scheduled maintenance all day and was accidentally energized and closed/tripped.

Question: We had a circuit out of service for scheduled maintenance all day and it was inadvertently energized and the breaker closed, then automatically tripped. Should be entered in TADS as a momentary outage.

Answer: For TADS, an AC Circuit must remain in an In-Service State for at least 1 minute for the Outage to be counted as a separate Outage. In this case, there would not be a second Outage because the closing/tripping occurred during an already occurring Planned Outage.

5. How to code an outage caused by vegetation within the right of way on a line with manual reclosing.

Question: A tree within the right of way falls through a line without damaging it, then manual reclosing takes place ten minutes later by design. How would I code this?

Answer: The initiating cause code would be reported as Vegetation and the sustained cause code would be Other since the reclosing occurred per procedure without any issues.

Event Related Questions

1. Clarification of “Normal Clearing”

Question: Clarification of “Normal Clearing”: If a breaker fails to trip from primary relaying but does successfully trip in the required time via secondary/backup relaying, is this considered normal or abnormal?

Answer: This is considered abnormal clearing according to the definitions. The outage should be coded with Event Type 61 (Dependability based).

Question: If a breaker trips due to lightning and doesn't reclose because of an issue reclosing, is this considered Normal Clearing or Abnormal Clearing?

Answer: For TADS, once the breaker correctly trips, it is Normal Clearing. Normal Clearing and Abnormal Clearing are only concerned with protection trips, intended (correct) or unintended (incorrect) clearing of an Element. It has nothing to do with reclosing functions.

2. Normal vs. Abnormal Clearing depending on normal clearing circuit breaker set.

Question: If a system is set up to clear more than one line during a fault (and this is the expected result) even though it is not normally set up this way (issue with breaker so two lines are being protected by single breaker), this would be Normal Clearing as well?

Answer: By manually changing whether the breaker is bypassed or not, the TO has indicated that it has changed its Normal Clearing Circuit Breaker Set. However, if the second AC Circuit cleared due to the primary protection failing or the backup protection overreaching, the Event would be Abnormal Clearing.

3. Catastrophic Failure of a Bus Potential Transformer



Figure D.3

Inventory Configurations with Reporting Examples

1. See Figure D.4 for the Following Questions:

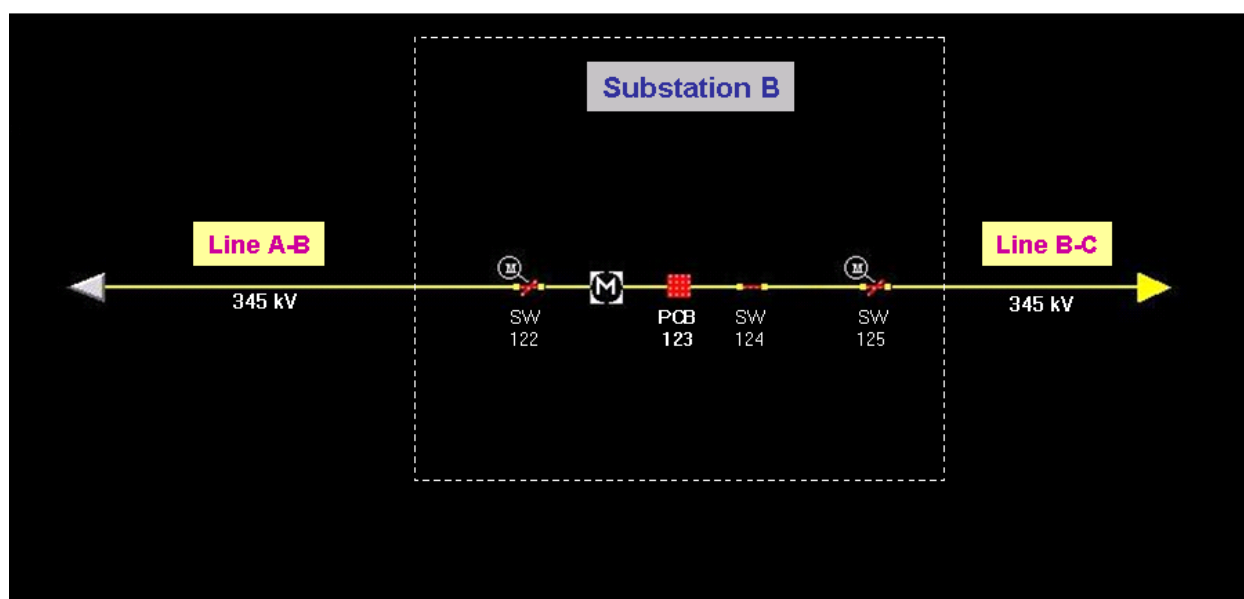


Figure D.4: At substation B, 345 kV line A-B connects to 345 kV line B-C via PCB 123.

a. What is the terminal of AC Circuit A-B at substation B?

SW122 and PCB123 are considered the terminal for the AC Circuit. SW122 and PCB123 must be closed for the AC Circuit to be considered In-Service.

b. What is the terminal of AC Circuit B-C at substation B?

SW125, SW124, and PCB123 are considered the terminal for the AC Circuit. SW125, SW124, and PCB123 must be closed for the AC Circuit to be considered In-Service.

c. If PCB123 trips from low gas but both lines remain energized from their remote ends and SW 122, 124, and 125 remain closed, are AC Circuit A-B and AC Circuit B-C still in service?

No. Neither AC Circuit A-B nor AC circuit B-C are “In-Service” (see definition of “In-Service State”) if PCB123 is open. Neither line is connected to its terminal at Substation B. This is a case where the two AC Circuits are sharing a common terminal. The two Outages would both be Common Mode Outages and have an Initiating Cause Code.

d. Assume that lightning strikes Line A-B and causes PCB123 to open. AC Circuit B-C remains energized from its remote end at Substation C. With PCB123 open is AC Circuit B-C still in service?

No. Because PCB123 is opened, the terminal connection is severed. AC Circuit B-C is no longer in an In-Service State (see definition of “In-Service State”) and an outage is reportable to TADS.

e. If AC Circuit B-C is considered to be interrupted in question #D, what is the outage mode?

Dependent Mode. The outage to AC Circuit B-C occurred as a consequence of the ‘lightning strike’ outage on Line A-B therefore AC Circuit B-C has an Outage Mode Code of Dependent Mode and AC Circuit A-C has an Outage Mode Code of Dependent Mode Initiating Outage. Both AC Circuit A-B and AC Circuit B-C would have an Initiating Cause Code of Lightning.

2. For the following questions, refer to Figure D.5:

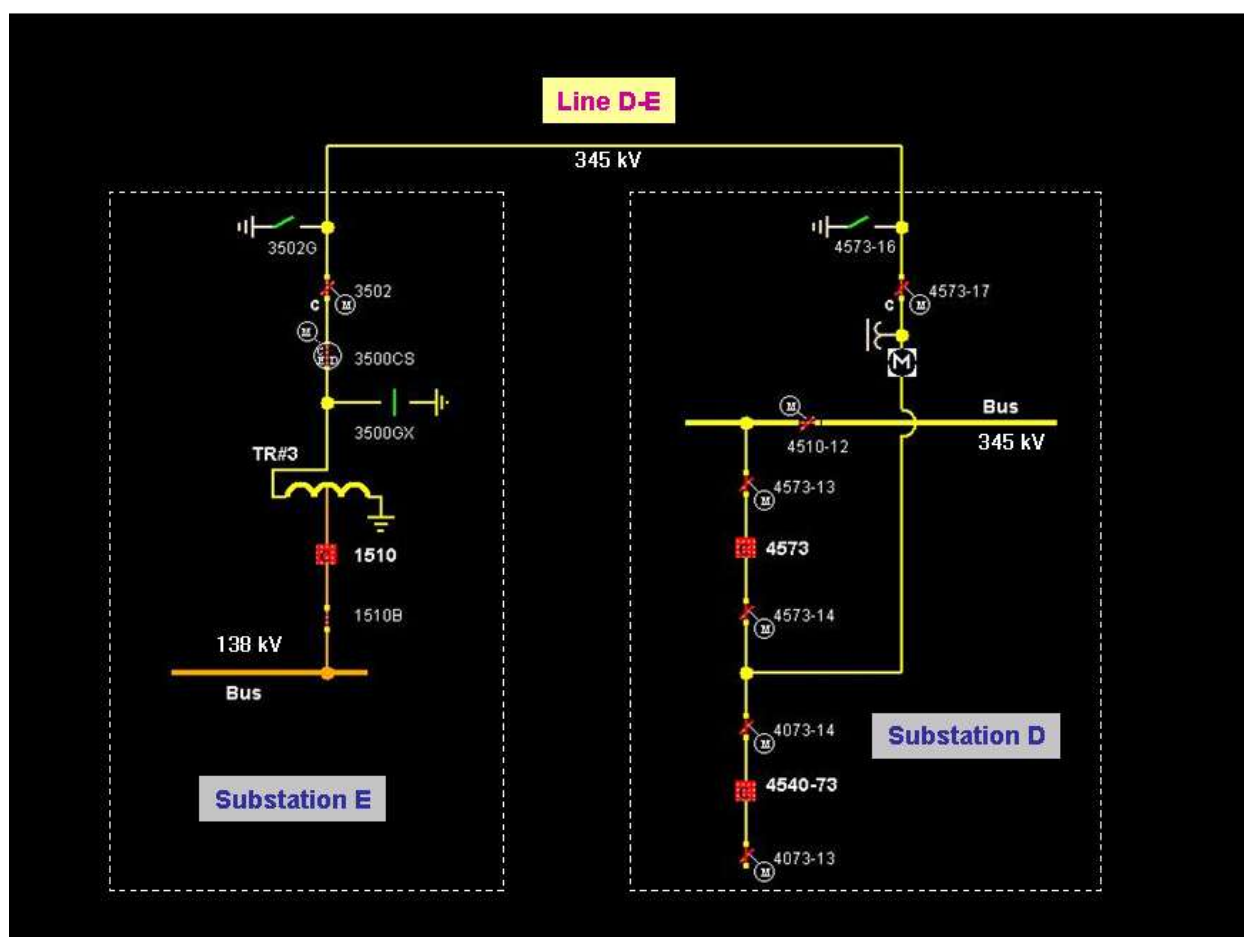


Figure D.5: AC Circuit D-E is a 345 kV radial feeder circuit that supplies a 345 kV/138 kV transformer at Substation E.

a. What is the terminal of AC Circuit D-E at substation E?

The terminal of AC Circuit D-E at Substation E would be comprised of SW3502 and 3500CS. Both must be closed in order for Line D-E to be fully connected at Substation E (see definition of “In-Service State”). Data that provides a description of the physical location of the Element terminals. Terminals are those buses on the element, behind which exist power sources. In general, these terminals will comprise the set of locations that need to open to clear faults on the element. Buses connected to the Element that serve only load, without power sources available behind them are not considered terminals.

b. If AC Circuit D-E remains energized from Substation D, does the automatic opening of 3500CS cause a TADS reportable interruption?

Yes. The Automatic opening of 3500CS would disconnect the terminal at Substation D of AC Circuit D-E. This would cause an Automatic Outage of AC Circuit D-E since AC Circuit D-E is no longer in an ‘In-Service State’.

c. If AC Circuit D-E remains energized from Substation D, does the automatic opening SW3502 cause a TADS reportable interruption?

Yes. Opening SW3502 would disconnect the terminal at Substation D of AC Circuit D-E. The AC Circuit would no longer be in an ‘In-Service State’ and hence is a reportable interruption.

d. If a transformer fault causes PCB1510 and 3500CS to open, is AC Circuit D-E still in service?

No, AC Circuit D-E is not in an In-Service State. Opening 3500CS would disconnect the terminal consisting of SW3502 and 3500CS. This would cause an Automatic Outage of AC Circuit D-E and hence a reportable interruption to Line D-E.

3. Please see Figure D.6 for the Following Questions:

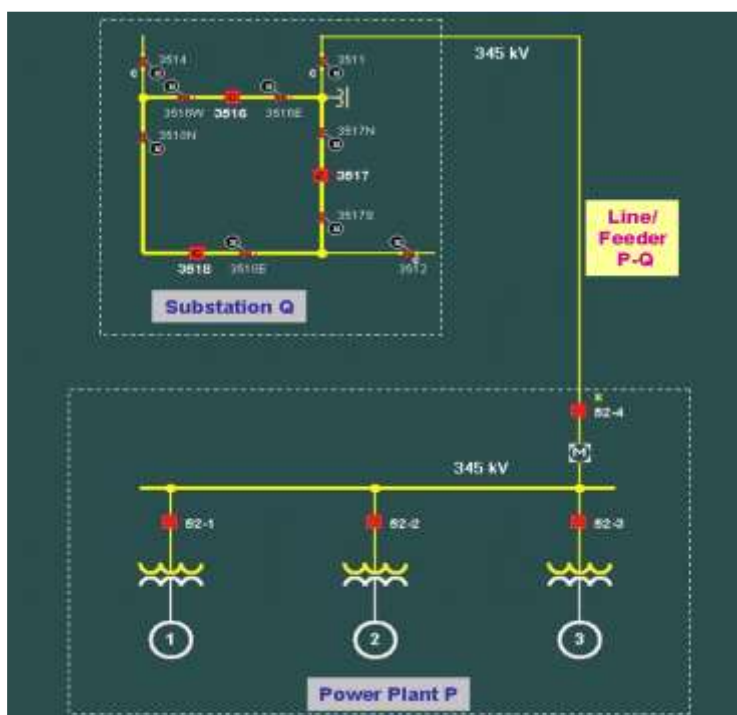


Figure D.6: Power Plant P connects to the grid at Substation Q via the generation feeder circuit P-Q.

a. Is the (generation) feeder circuit P-Q considered a line for TADS purposes?

If the feeder AC Circuit P-Q is either completely or partially owned by an Entity with a Transmission Owner function, the AC Circuit should be reported for TADS purposes. TADS only applies to the Transmission Owner function.

b. If so, what are the terminals?

The terminal at Power Plant Q is 52-4. The terminal at Substation Q is switch 3511 and 3516 (and its associated disconnects 3516W and 3516E) OR 3517 (and its associated disconnects 3517N and 3517S). For power to flow, 52-4 and 3511 must be closed. Additionally, either 3516 (and its associated disconnects 3516W and 3516E) OR 3517 (and its associated disconnects 3517N and 3517S) must be closed.

c. If the circuit remains energized and connected at Substation Q, does opening PCB 52-4 at Power Plant P cause an interruption?

Yes, the terminal at 52-4 would be disconnected. This would place the AC Circuit P-Q in a non-In-Service State.

d. Would the opening of only Breaker 3516 result in an interruption to Circuit P-Q?

No, the opening of Breaker 3516 by itself would not result in an interruption to Line P-Q (if all other Breakers and Switches remained closed). It would take an opening Breaker 3516 and Either Breaker 3517 or one of the switches (3517S or 3517N) to result in an interruption to Circuit P-Q at Substation Q.

4. Please see Figure D.7 for the following questions:

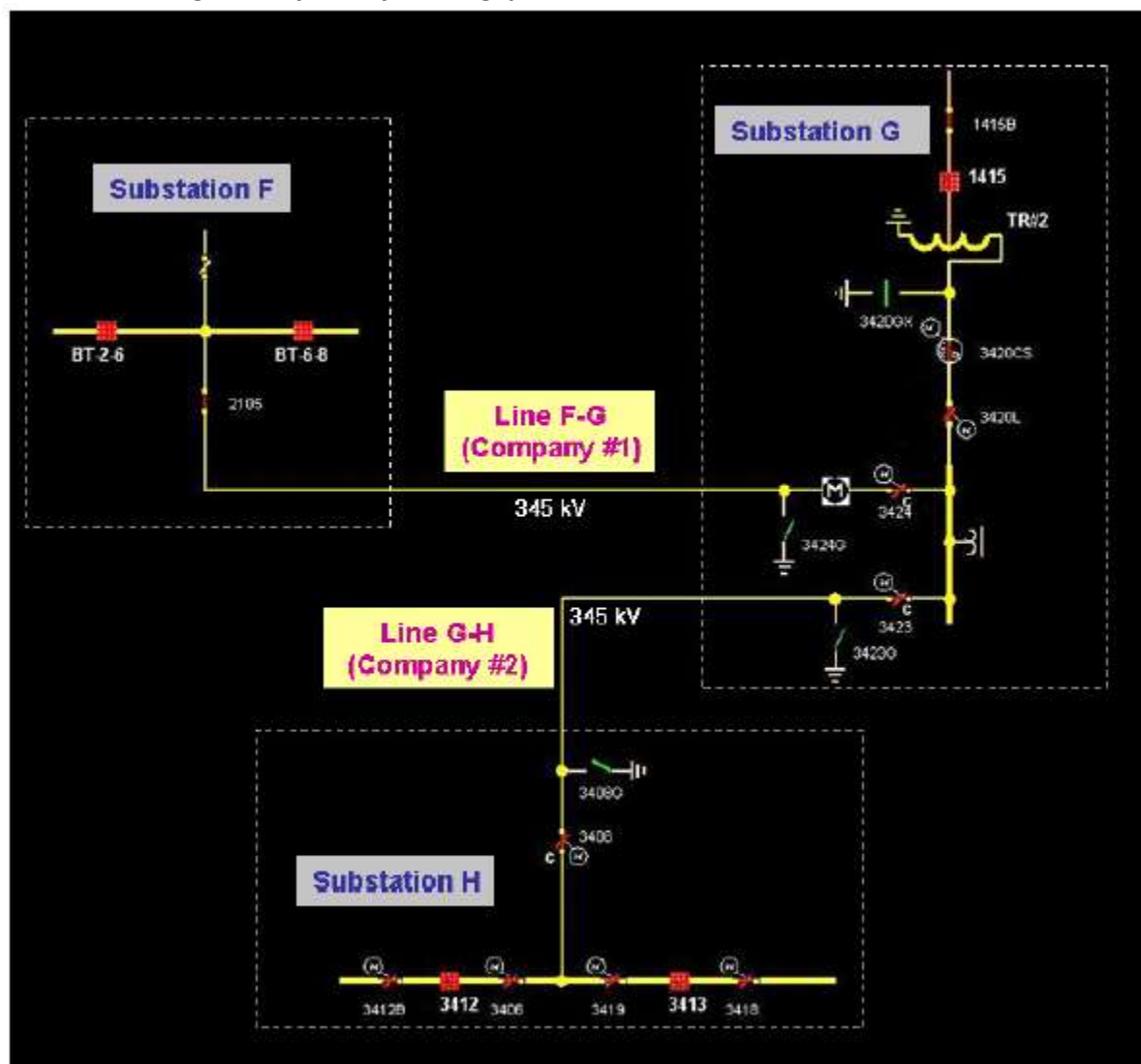


Figure D.7: Line [section] F-G is owned and operated by Company #1. Line [section] G-H is owned and operated by Company #2.

Note: There is no fault current interrupting device between line section F-G and line section G-H. When one line encounters a fault, both lines sections must trip in order to clear the fault.

a. Is line [section] F-G considered a separate line from line [section] G-H for TADS purposes?

No. Since there is no fault interrupting device at Station G between line section F-G and line section G-H, it is a single AC Circuit F-H. Company 1 and Company 2 must agree which single company of the two will include AC Circuit F-H in its detailed inventory (Form 3.1) and that company will also submit all TADS interruptions on AC

Circuit F-H. Both companies will submit information for AC Circuit F-H in Form 2.1 with the agreed upon 'Reporting TO Element ID' and the agreed upon 'Reporting Transmission Owner Name'.

b. If so, what is the terminal for line [section] F-G at Substation G? SW3424?

F-G is only a line section and not an entire AC Circuit and SW3424 is not a terminal. However, AC Circuit F-H may have a terminal at Substation G if it is a true 3-terminal line. If the equipment beyond Breaker 3420CS is more than just a load and Breaker 3420CS is part of the Normal Clearing Circuit Breaker Set (NCCBS) for AC circuit F-H then AC Circuit F-H is a 3-terminal line with a terminal at Breaker 3420CS (and disconnect 3420L).

c. If so, what is the terminal for line [section] G-H at Substation G? SW3423?

G-H is only a line section and not an entire AC Circuit and SW3423 is not a terminal. However, AC Circuit F-H may have a terminal at Substation G if it is a true 3-terminal line. If the equipment beyond Breaker 3420CS is more than just a load and Breaker 3420CS is part of the Normal Clearing Circuit Breaker Set (NCCBS) for AC circuit F-H then AC Circuit F-H is a 3-terminal line with a terminal at Breaker 3420CS (and disconnect 3420L).

5. Please see Figure D.8 for the following questions:

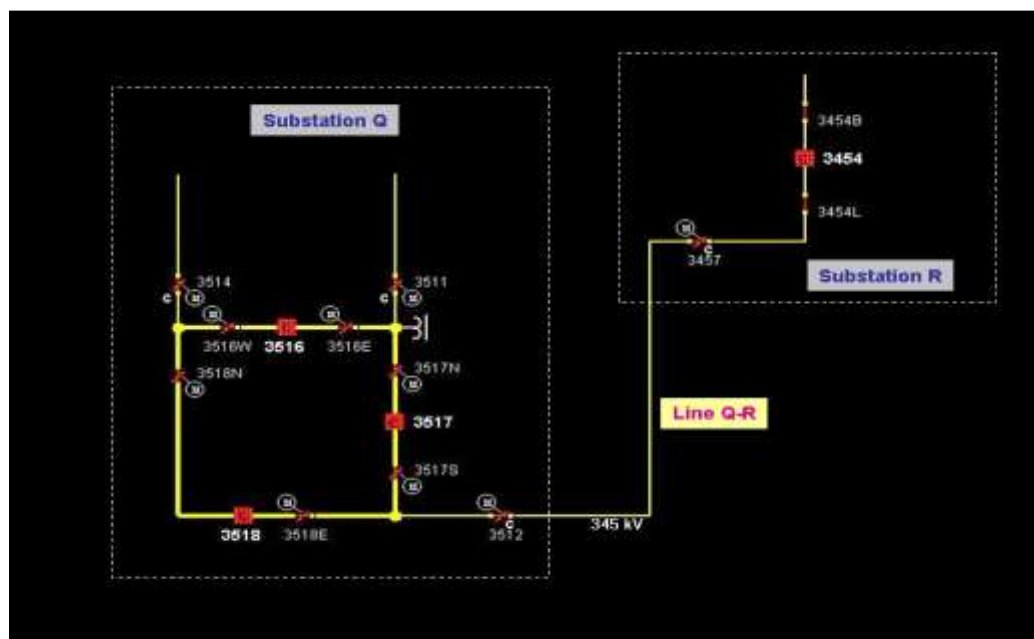


Figure D.8: AC Circuit Q-R is a 345 kV circuit between Substation Q and Substation R. The AC Circuit connects to a ring bus at Substation Q.

a. What is the terminal of AC Circuit Q-R at substation Q?

The terminal for AC Circuit Q-R at substation Q would comprise the switches/breakers: 3512, 3518E, 3518N, 3518, 3517S, 3517N and 3517. To determine whether AC Circuit Q-R meets the definition of an In-Service State, you must determine whether power can flow from Substation Q to Station R (or vice-versa). At Substation Q: First, switch 3512 must be closed. Secondly, either Breaker 3518 or its associated disconnects (3518N and 3518E) OR Breaker 3518 and its associated disconnects (3517N and 3517S) must be closed. At Substation R: 3454, 3454B, 3454L and 3457 must all be closed.

- b. If both Breaker 3517 and Breaker 3518 are open at Substation Q but AC Circuit Q-R remains energized from Substation R and SW 3512 remains closed, is AC Circuit Q-R in an In-Service State?***

No. AC Circuit Q-R is not considered in an In-Service state because it is not connected at all its terminals (Substation Q) (even though the AC Circuit is energized). It is no longer possible for power to flow from Substation Q to Substation R.

- c. What is the terminal of AC Circuit Q-R at Substation R?***

The terminal at substation R for Line Q-R would consist of the switches/breakers: Switch 3457 and Breaker 3454 and its associated disconnects (3454B and 3554L). All of these would need to be closed for AC Circuit Q-R to be connected at its terminal at Substation R.

- d. Assume that all breakers and switches at Substation Q are closed and AC Circuit Q-R is energized from Substation Q. If Breaker 3454 is opened at Substation R, but SW 3457 and SW 3454L remain closed, is AC Circuit Q-R still in an In-Service State?***

No. AC Circuit Q-R is not considered in an In-Service State because it is not connected at all its terminals (Substation R) (even though the AC Circuit is energized). It is no longer possible for power to flow from Substation Q to Substation R (or vice versa).

- e. Assume that all breakers and switches at Substation Q are closed and AC Circuit Q-R is energized from Substation Q. If SW 3454L is opened with SW 3457 closed at Substation R, is AC Circuit Q-R still in an In-Service State?***

No. AC Circuit Q-R is not considered in an In-Service State because it is not connected at all its terminals (Substation R) (even though the AC Circuit is energized). It is no longer possible for power to flow from Substation Q to Substation R (or vice versa).

- 6. For the following questions, refer to Figure D.9:**

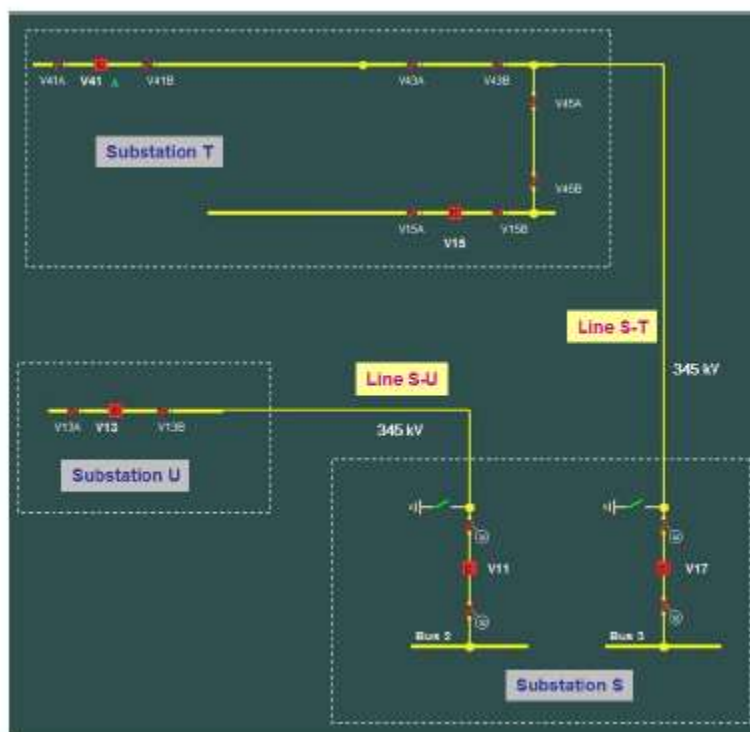


Figure D.9: AC Circuit S-T is a 345 kV circuit between Substation S and Substation T.

- a. AC Circuit S-T trips and recloses during a storm with a P-G fault (Breakers V17, V41 and V15). Because of a failed communications circuit, the remote end of AC Circuit S-U trips and recloses at Substation U (Breaker V13). What is this the correct way to report these interruptions?

Table D.1		
	Form 4.1 – AC Circuit S-T	Form 4.1- AC Circuit S-U
Fault type:	P-G fault	No fault
Outage Initiation Code	Element-Initiated	Protection System-Initiated
Initiating Cause Code	Weather, excluding lightning	Failed Protection System Equipment
Sustained Cause Code	N/A - Momentary	N/A - Momentary
Outage Mode Code	Dependent Mode Initiating	Dependent Mode

Both interruptions will use the same TADS Event ID Code with Event Type = 62.

7. For the following questions, refer to Figure D.10:

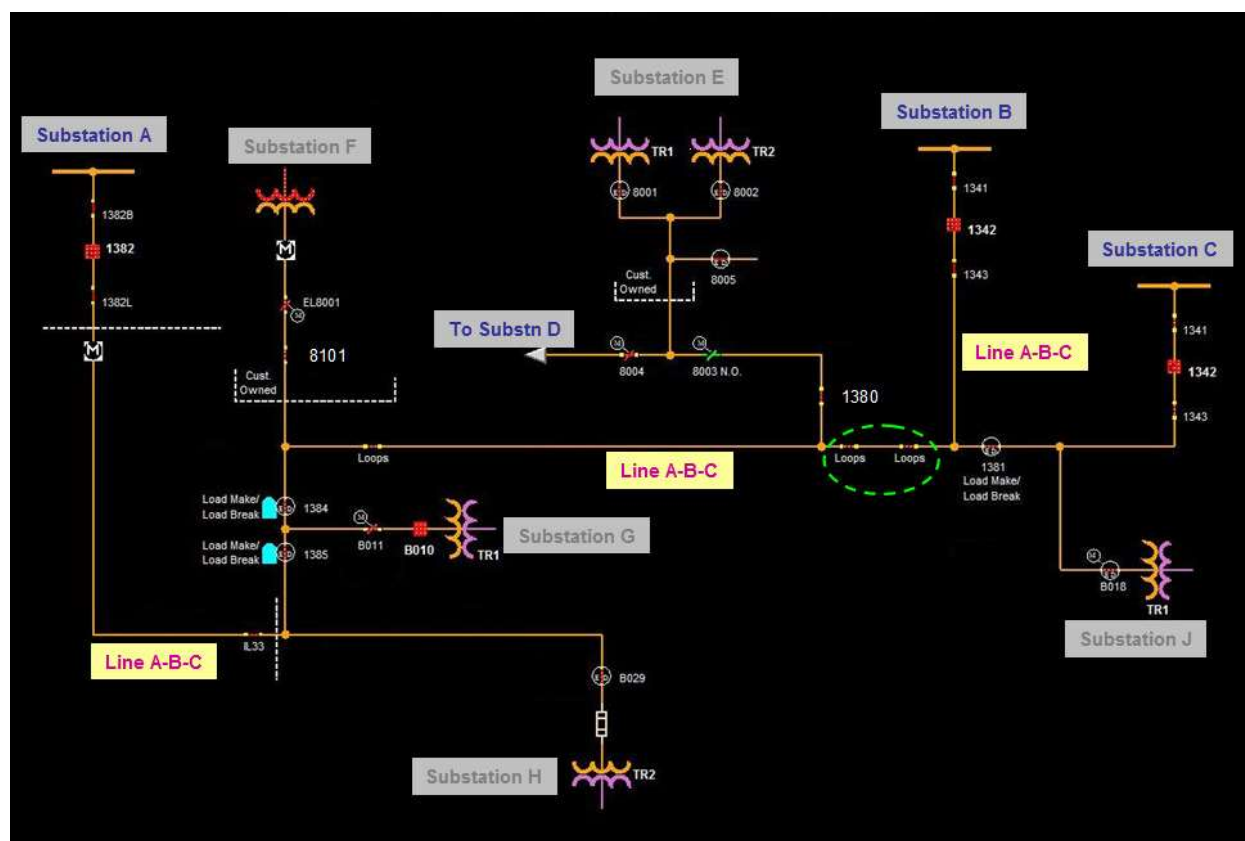


Figure D.10: Assume that AC Circuit A-B-C is a 345 kV circuit with multiple radial feeds to sub-100 kV transformers.

- a. Assume that loops are opened as circled in green in the diagram, but the AC Circuit is fully energized and all breakers are closed. Is this AC Circuit in an In-Service State with the loops opened? (For this example, Substations A, B, and C (3 terminal line) are considered to be networked transmission stations and Substations D, E, F, G, H, and J are considered to be tapped load connection points on the AC Circuit A-B-C.)*

No. With the loops opened in the middle of AC Circuit A-B-C, the AC Circuit is no longer in an In-Service State. The intent of “connected at all of its terminals to the system” in the definition of In-Service State is that power can freely flow between all of the Element’s terminals (in this case: Substation A, Substation B, and Substation C). With any of the loops (or a switch such as IL33, 1384, 1385, or 1381) open in the middle of the AC Circuit, power can no longer flow between all the terminals and the AC Circuit is no longer in an In-Service State.

- b. If switch 8101 is opened at Substation F with all other breakers/switches closed and the line energized, is AC Circuit A-B-C in service?*

Yes, AC Circuit A-B-C is still in an In-Service State. Substation F is a tapped load connection point to the AC Circuit A-B-C and is not essential for the transmission line for power flow between Substation A, Substation B, and Substation C. Substation F and its associated tap line is not a terminal of AC Circuit A-B-C.

- c. If inline switch 1380 near Substation E is opened with all other breakers/switches closed and the line energized, is AC Circuit A-B-C in service?*

Yes, AC Circuit A-B-C is still in an In-Service State. Substation E and Substation D are tapped load connection points to the AC Circuit A-B-C and is not essential for the transmission line for power flow between Substation A, Substation B, and Substation C. (Substation D, though not shown, is considered to be another tapped load connection point.)

8. Temporarily Jumpered AC Circuit

At a station that has numerous transmission lines:

An Automatic outage occurs on one AC Circuit (Line 1) starting on 5/17/2010. Before the AC Circuit is restored, Line 1 is temporarily jumpered (around the affected station) on 7/1/2010 to another AC Circuit (Line 2). The single 'new' (temporary) AC Circuit (Line 3 = Line 1 + Line 2) is then energized and connected to the system (although not in their 'normal' configuration) through the opposite ends (with no 'terminal' at the affected station). The circuit breakers at the affected station have been jumpered around and are out-of-service (but by definition are not part of the AC Circuit). It may remain like this for several months for example until 1/17/2011.

- a. Since the AC Circuits are energized and connected to the system, they are technically "in-service". Correct? However, the outage duration definition states that it is "the amount of time the Element is fully restored to its original or normal configuration".***

If the AC Circuits are to be temporarily configured in this situation with a planned restoration date, then the preferred (recommended) method is to continue reporting as 2 separate lines. The utility will need then to report 2 outages for each interruption that occurs during this time frame.

- b. Should this outage be reported as approximately 1.5 months or 8 months?***

1.5 Months. For the outage listed above, the utility should report one Automatic outage starting on 5/17/2010 and ending on 7/1/2010. Any Automatic (or Operational) interruptions that occur while the two lines are tied together should be reported simultaneously on **both** lines.

9. Ring Bus Fault Locations

Question: What Outage Initiation codes should be reported for the respective faults on the diagram below?

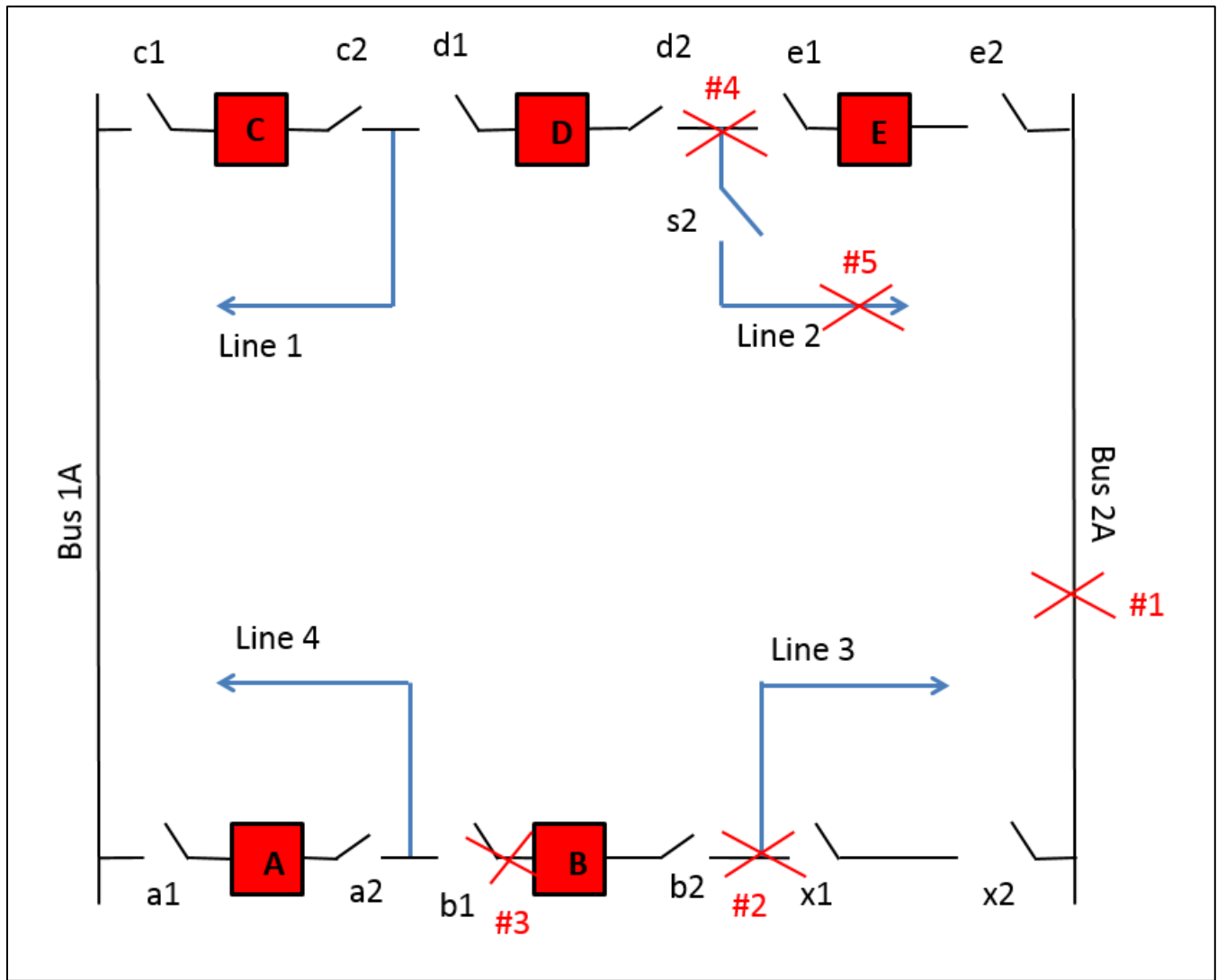


Figure D.11

Answer:

- Fault #1 on Bus 2A: Initiation Code = 'AC Substation Initiated'
- Fault #2: Initiation Code = 'Element Initiated'
- Fault #3: Initiation Code = 'AC Substation Initiated'
- Fault #4: Initiation Code = 'AC Substation Initiated'
- Fault #5: Initiation Code = 'Element Initiated'

Appendix E: Metrics

Metrics below 200 kV:

No.	Metric	Formula	Units	Definition	Acronym
Element Outage Frequency					
2	Element Sustained Outage Frequency	Total Sustained Outages / Total Elements	# of Outages	# Sustained Outages per Element per year	SOF
Element Outage Duration, Repair time and Up time					
4	Element Sustained Outage Duration Time	Total Sustained Outage Hours / Total Elements	# of Hours	Average # of sustained outage hours per element per year	SODT
5	Element Sustained Outage Mean Time to Repair	Total Sustained Outage Hours / Total Sustained Element Outages	# of Hours	Average # of Sustained Outage hours per outaged element	MTTR
6	Median Time to Repair Sustained Element Outage Failures	The time when 50% of the mean time to repair minutes are greater than this figure	# of Hours	Median # of Sustained Outage Hours per outaged Element	MdTTR
7	Mean Time Between Sustained Element Outages (Mean "Up Time"). Also referred to as mean time between failures	(Total Element Hours - Total Sustained Outage Hours) / Total Sustained Element Outages	# of hours	Mean # of hours of operation an element has before failure	MTBF
Element Availability					
8	Element Availability Percentage	[1-(Total Sustained Outage Hours / Total Element Hours)] * 100	%	Percentage of time that an element is available	APC
10	Percent of Element Automatic Outages associated with a Disturbance Report (EOP0004)	Total Automatic Outages associated with a Disturbance Report / Total Automatic Outages	%	Percentage of automatic outages associated with a disturbance report	PCDR
Circuit Outage Frequency, per 100 Circuit Miles (Applies to AC and DC Circuits Only)					
12	Circuit Sustained Outage Frequency, Mileage Adjusted	(Total Circuit Sustained Outages * 100) / Total Circuit Miles	# of outages	# Sustained Outages per 100 circuit miles per year	SCOF100CT mi
Frequency per 100 Multi-Circuit Structure Miles (For AC Circuits, multi circuit outages are Event Type 31 outages; for DC Circuits, they are Event Type 31 outages.)					
15	Multi-Circuit Sustained Outage Frequency, Mileage Adjusted	(Total Multi Circuit Sustained Outages * 100) / Total Multi Circuit Structure Miles	# of outages	# Sustained Outages per 100 multi-circuit miles per year	SMOCF100ST mi
Phase II Metrics and Updated Phase I Metrics					
14	Maximum Percent of Simultaneous Element Outages	Point in time when outages due to sustained automatic outages are at their maximum	%	Point in time when outages due to sustained automatic outages are at their maximum	MSIM

Metrics 200 kV and above

No.	Metric	Formula	Units	Definition	Acronym
Element Outage Frequency					
1	Element Total Automatic	Total Automatic Outages / Total Elements	# of Outages	# Automatic Outages per element per year	TOF
2	Element Sustained Outage Frequency	Total Sustained Outages / Total Elements	# of Outages	# Sustained Outages per Element per year	SOF
3	Element Momentary Outage Frequency	Total Momentary Outages / Total Elements	# of Outages	# Momentary Outages per Element per year	MOF
Element Outage Duration, Repair time and Up time					
4	Element Sustained Outage Duration Time	Total Sustained Outage Hours / Total Elements	# of Hours	Average # of sustained outage hours per element per year	SODT
5	Element Sustained Outage Mean Time to Repair	Total Sustained Outage Hours / Total Sustained Element Outages	# of Hours	Average # of Sustained Outage hours per outaged	MTTR
6	Median Time to Repair Sustained Element Outage Failures	The time when 50% of the mean time to repair minutes are greater than this figure	# of Hours	Median # of Sustained Outage Hours per outaged Element	MdTTR
7	Mean Time Between Sustained Element Outages (Mean "Up Time"). Also referred to as mean time between failures	(Total Element Hours - Total Sustained Outage Hours) / Total Sustained Element Outages	# of hours	Mean # of hours of operation an element has before failure	MTBF
Element Availability					
8	Element Availability Percentage	[1-(Total Sustained Outage Hours / Total Element Hours)] * 100	%	Percentage of time that an element is available	APC
9	Percentage of Elements with Zero Automatic Outages	Total Elements with Zero Automatic Outages / Total Elements	%	Percentage of elements with no automatic outages	PCZO
10	Percent of Element Automatic Outages associated with Disturbance Report (EOP004)	Total Automatic Outages associated with a Disturbance Report / Total Automatic Outages	%	Percentage of automatic outages associated with a disturbance report	PCDR
Circuit Outage Frequency, per 100 Circuit Miles (Applies to AC and DC Circuits Only)					
11	Circuit Total Outage Frequency, Mileage Adjusted	(Total Circuit Automatic Outages * 100) / Total Circuit Miles	# of outages	# Automatic Outages per 100 circuit miles per year	TCOF100CTmi
12	Circuit Sustained Outage Frequency, Mileage Adjusted	(Total Circuit Sustained Outages * 100) / Total Circuit Miles	# of outages	# Sustained Outages per 100 circuit miles per year	SCOF100CT mi
13	Circuit Momentary Outage Frequency, Mileage Adjusted	(Total Circuit Momentary Outages * 100) / Total Circuit Miles	# of outages	# Momentary Outages per 100 circuit miles per year	MCOF100CTmi
Frequency per 100 Multi-Circuit Structure Miles (For AC Circuits, multi circuit outages are Event Type 31 outages; for DC Circuits, they are Event Type 31 outages.)					
14	Multi Circuit Total Outage Frequency, Mileage Adjusted	(Total Multi Circuit Automatic Outages * 100) / Total Multi Circuit Structure Miles	# of outages	# Automatic Outages per 100 multi circuit structures miles per year	TMCOF100STmi
15	Multi Circuit Sustained Outage Frequency, Mileage Adjusted	(Total Multi Circuit Sustained Outages * 100) / Total Multi Circuit Structure Miles	# of outages	# Sustained Outages per 100 multi-circuit miles per year	SMOCF100ST mi
16	Multi Circuit Momentary Outage Frequency, Mileage Adjusted				MMCOF100STmi
Phase II Metrics and Updated Phase I Metrics					
3	Element Operational Outage Frequency	Total Operational Outages / Total Elements	# of outages	# operational outages per element per year	OOF
10	Element Total Operational Outage Duration Time	Total Operation Outage Hours / Total Elements	# of hours	Avg # of operational outage hours per element per year	OODT
11	Mean Total Operational Outage Duration Time	Total Operational Outage Hours / Total Operational outage elements	# of hours	Avg # of operational outage hours per element per year	MOOT
12	Median Total Operational Outage Duration Time	The time when 50% of the operational outage time are greater than this figure	# of Hours	Median # of operational outage hours per Element per year	MdOOT

Appendix F: Revision History

Version	Date	Revisions
1.0	10/3/2019	Initial Release
2.0	1/29/2021	Failed Protection System cause code definition; Removed data fields not collected; Added procedure to add more than one Outage to the same Event ID that are more than one minute apart; Added procedure to handle long duration outages
3.0	1/4/2022	Under “Who Must Report”: Removed “TOs that register during a reporting calendar year are not subject to any TADS reporting requirements until the next calendar year. However, a TO may voluntarily report data for the year that it first becomes newly registered.” This is a legacy requirement that is no longer needed. Under Form 3.3, Table 3.3 should be referenced, not Table 3.2. Table 3.3 (incorrectly referenced as Table 3.2): “Update text to “Column D (Change/Reconfiguration Data) is when the element was placed in-service. If this is unknown, use January 1 of the current year you are reporting. If the element is altered/reconfigured in a way that would change its rating or voltage characteristics, then that date would be entered here.” Table 5.1: Column B- Change “P” to “K” Table 6.1: Changed wording in Column A to “...TO entered Form 4.x Outage ID to be used only once on a Non-Automatic Outage (on Form 4.x) In Table 6.1, removed Column G – Operational Outages enter “NA”. Renumbered subsequent columns.
4.0	1/2/2024	Under the TADS population outage definitions, a reference has been added that there is an exclusion example provided in Fig A.7 for In-Service Sate. The Vandalism, Terrorism, and Malicious Acts cause code has been updated to Physical Security Incident to distinguish it from Cyber Security Incident.

Appendix E
NATF Definitions

This document is classified as confidential. In order to minimize administrative burden to the Commission and to the parties, we are not attaching the document itself, but we can produce or file it upon request in conformance with the Commission's guidelines around submission of confidential materials.

Appendix F

Annual Electric Power Industry Report (EIA 861)

EIA-861 ANNUAL ELECTRIC POWER INDUSTRY REPORT

YOUR RESPONSE IS REQUIRED BY LAW

This report is mandatory under Title 15 U.S.C. §772(b). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by Title 15 U.S.C. §797. Title 18 U.S.C. §1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.

The Form EIA-861 must be completed by electric power industry entities such as, but not limited to, electric utilities, all Demand Side Management (DSM) Program Managers (entities responsible for conducting or administering a DSM program), wholesale power marketers, energy service providers, electric power producers, transmission owners, transmission operators, and Third Party Owners of solar PV (TPO). Responses are collected at the operating company level (not at the holding company level).

PURPOSE

The Energy Information Administration (EIA) Form EIA-861, *Annual Electric Power Industry Report*, collects information on the status of electric power industry participants involved in the generation, transmission, distribution, and sale of electric energy in the United States and its territories. The data from this form are made available in EIA publications and databases. The data collected on this form are used to monitor the current status and trends of the electric power industry and to evaluate the future of the industry.

RESPONSE DUE DATE

The Form EIA-861 must be received by EIA by April 30, following the end of the calendar year.

HOW TO FILE A RESPONSE

Respondents should transmit data using EIA's secure internet data collection system (e-file). This system uses security protocols to protect information against unauthorized access during transmission.

- If you have not registered with EIA's Single Sign-On system, send an email requesting assistance to the EIA Survey Support Team at eia4usa@eia.gov
- If you have registered with Single Sign-On, log on at <https://signon.eia.gov/ssoserver/login>

Please retain a completed copy of this form for your files. Copies in spreadsheet format (XLS) are available on EIA's website. You may access the materials here: <https://www.eia.gov/survey/#eia-861>

EIA does not accept email, fax, or paper forms.

QUESTIONS

Please contact the EIA Survey Support Team using the following communication methods:

By email: eia4usa@eia.gov
By phone: 1-855-EIA-4USA (1-855-342-4872) [Monday through Friday, 8:00 AM to 6:00 PM E.T.]

SANCTIONS

The timely submission of Form EIA-861 by those required to report is mandatory under 15 USC 772(b), as amended. Failure to respond may result in a civil penalty of not more than \$10,633 each day for each violation. The government may bring a civil action to prohibit reporting violations which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements.

REPORTING BURDEN

Public reporting burden for this collection of information is estimated to average 12.75 hours per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to: Energy Information Administration, Statistical Methods and Research, EI-21, 1000 Independence Avenue, S.W., Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DISCLOSURE OF INFORMATION

The following information reported on this survey will be protected and not disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the Department of Energy (DOE) regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905:

- All information associated with the “Survey Contact” and the “Supervisor of Contact Person for Survey” on SCHEDULE 1 or SCHEDULE 4.
- The information reported on SCHEDULE 2, PARTS B, C, and D, and SCHEDULE 3 for power marketers. This information will be protected and not publicly released in identifiable form for nine (9) months after the end of the reporting year. After nine (9) months from the end of the reporting year this information will be considered nonsensitive and may be publicly released in identifiable form.

All other information reported on Form EIA-861 is considered public information and may be publicly released in company identifiable form. The Federal Energy Administration Act requires EIA to provide company-specific data to other Federal agencies when requested for official use. The information reported on this form may also be made available, upon request, to another component of the Department of Energy (DOE) to any Committee of Congress, the Government Accountability Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order. The information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.

Disclosure limitation procedures are not applied to the aggregate statistical data published from this survey. There may be some statistics that are based on data from fewer than three respondents, or that are dominated by data from one or two large respondents. In these cases, it may be possible for a knowledgeable person to closely estimate the information reported by a respondent.

GENERAL INSTRUCTIONS

Respondents who also submit the Form EIA-861M (Formerly EIA-826), *Monthly Electric Sales and Revenue Report with State Distributions*, should coordinate the information submitted on the Form EIA-861 and Form EIA-861M to ensure consistency.

Report peak demand in megawatts and energy values (e.g., generation and sales) in megawatt hours, except where noted. One megawatt hour equals 1,000 kilowatt hours. To convert kilowatt hours to megawatt hours, divide by 1,000 and round to the nearest whole number. For example, sales of 5,245,790 kilowatt hours should be reported as 5,246 megawatt hours.

Report in whole numbers (i.e., no decimal points), except where explicitly instructed to report otherwise. For example: revenue of \$8,459,688.42 should be reported as 8,460 (thousand dollars). There is one decimal place in the revenue on Schedules 2C and 4. Lines 2 and 4 on Schedule 6A and lines 3 and 4 on Schedule 6B also contain one decimal point.

For the on-line form only, a State Code can only be removed by highlighting the state and clicking on the **'Remove record'** button. (Schedules 3A-C, 4A-D, 6A-D, 7A and 7B).

For number of customers, enter the average of the 12 close-of-month customer accounts.

- All respondents having end-use customers, including retail power marketers selling power in deregulated, competitive state programs must use the average of the 12 close-of-month customer counts when reporting on Schedule 4, even if your company began business after the beginning of the reporting year, or ended business before the close of the year.
- Count each meter as a separate customer in cases where commercial franchises or residential customer-buying groups have been aggregated under one buyer representative. The customer counts for public street and highway lighting should be one customer per community.
- Please do not count each pole as a separate customer even if billing is by a flat rate per pole per month.

Use a minus sign for reporting negative numbers. Line 9 on Schedule 2B must be a negative number. On Schedule 2B, line 1 and Schedule 2C, lines 4 and 6, the number may be either positive or negative.

Where exact data are unavailable, report estimated data.

See the [Glossary](#) for terms used in this survey. The financial and accounting terms are consistent as outlined in the Uniform System of Accounts for Public Utilities and Licensees (U.S. of A.) (18 CFR Part 101).

Ownership Codes

Municipal Marketing Authority (A): Voted into existence by the residents of a municipality and given authority for creation by the state government. They are nonprofit organizations.

Behind the Meter (B): Entities that install, own, and/or operate a system (usually photovoltaic), and sell, under a long term power purchase agreement (PPA) or lease, all the production from the system to the homeowner or business with which there is a net metering agreement. **Third Party Owners (TPOs)** of PV solar installations use this ownership code.

Cooperative (C): Member-owned organizations.

Nonutility DSM Administrator (D): Only involved with Demand-Side Management activities.

Federal (F): Government agencies with the authority to deliver energy to end-use customers.

Investor-Owned Utilities (I): Entities that are privately owned and provide a public service.

Municipal (M): Entities that are organized under authority of state statute to provide a public service to residents of that area.

Political Subdivision (P) (also called "public utility district"): Independent of city or county government and voted into existence by a majority of the residents of any given area for the specific purpose of providing utility service to the voters. State laws provide for the formation of such districts.

Independent Power Producer or Qualifying Facility (Q): Entities that own power plants and sell their power into the wholesale market.

Retail Power Marketer (R) or Energy Service Provider: Entities that market power to customers in restructured markets.
State (S): Entities that own or operate facilities or provide a public service.

Transmission (T): Entities that operate or own high voltage transmission wires that provide bulk power services.

Wholesale Power Marketer (W): Entities that buy and sell power in the wholesale market.

SPECIFIC INSTRUCTIONS

SCHEDULE 1: IDENTIFICATION

Survey Contact: Verify contact name, title, email address, telephone number, fax number.

Supervisor of Contact Person for Survey: Verify the contact's supervisor's name, title, address, telephone number, fax number and email address. **Supervisor contact must be different than the survey contact.**

If any of the above information is incorrect or missing, please send revisions to the EIA Survey Support Team at eia4usa@eia.gov

Entity and Preparer Information

Legal Name of Entity: Enter the legal name of the entity for which this form is being prepared.

Current Address of Entity's Principal Business Office: Enter the complete address, excluding the legal name, of the entity's principal business office (i.e., headquarters, main office, etc.).

Preparer's Legal Name: Enter the legal name of the company that prepares this form, *if different from the Legal Name of Entity*.

Current Address of Preparer's Office: Enter the address to which correspondence regarding this form should be mailed, if different from the *Current Address of Entity's Principal Business Office*. Include an attention line, room number, building designation, etc. to facilitate the future handling and processing of the Form EIA-861.

SCHEDULE 2, PART A: GENERAL INFORMATION

For line 1, please check all the Regional Entities within the North American Electric Reliability Corporation (NERC), in which your organization conducts operations.

The Regional Entities are:

- TRE (Texas Reliability Entity [ERCOT])
- FRCC (Florida Reliability Coordinating Council)
- MRO (Midwest Reliability Organization)
- NPCC (Northeast Power Coordinating Council)
- RFC (ReliabilityFirst Corporation)
- SERC (SERC Reliability Corporation)
- SPP (Southwest Power Pool, RE)
- WECC (Western Electricity Coordinating Council)

For line 2, select the RTO or ISO from the list:

- California ISO
- Electric Reliability Council of Texas
- Southwest Power Pool
- Midwest ISO
- PJM Interconnection
- New York ISO
- ISO New England
- None

For line 4, **Operate Generating Plant(s)**, check 'Yes' to indicate that your organization operated at least one generating plant during the reporting period. Otherwise, check 'No.'

For line 5, **Activities**, check the appropriate activities the electric entity was engaged in during the reporting year. If your activity is not listed on line 5, include in Schedule 9. At least one activity must be provided.

- **Generation from company owned plant.** Owned power generation.
- **Transmission.** Owned or leased transmission lines.
- **Buying transmission services on other electrical systems.** Types of services include borderline customers, transmission line rental, transmission capacity, transmission wheeling, and system operational services.
- **Distribution using owned/leased electrical wires.** Power delivery to your own end-use customers over distribution facilities.
- **Buying distribution on other electrical systems.** Types of support include customer billing, distribution system support charges for energy delivered, line maintenance, and/or equipment charges.
- **Wholesale power marketing.** Wholesale transactions with other electric utilities, purchases from power producers, and transactions to export and/or import electricity to or from Canada or Mexico. Also includes electrical sales and purchases among Federal Energy Regulatory Commission (FERC) registered power marketers and similar participation in transactions with electric utilities.
- **Retail power marketing.** Provision of electrical energy to end-use customers in areas where the customer has been given the legal right to select a power supplier other than the "traditional electric utility."
- **Combined services.** Provision of electricity in combination with gas, water, cable, Internet, and/or telephone for a single price.

For line 6, **Highest Hourly Electrical Peak System Demand (MW)**, electric utility companies should enter the maximum hourly summer load (for the months of June through September) based on net energy for the system during the reporting year. Net energy for the system is the sum of energy an electric utility needs to satisfy their service area and includes full and partial wholesale requirements customers, and the losses experienced in delivery. The maximum hourly load is determined by the interval in which the 60-minute integrated demand is the greatest. If such data are unavailable, adjust available data to approximate a 60-minute demand interval and explain the adjustment on Schedule 9 (Footnotes). If adjustments cannot be made, furnish data as available and explain on Schedule 9. For winter, enter the maximum hourly winter load (for months of January through March, and the previous December) based on the net energy for the system during the reporting year. Please note: These data elements should be provided in megawatts, to the nearest tenth.

For line 7, **Alternative-Fueled Vehicles**, check 'Yes' to indicate that your company owns/operates, or plans to own and operate, alternative-fueled vehicles; otherwise check 'No.' If "Yes," provide the name, title, FAX number, telephone number, and address of a contact person. Note: For the purpose of this question, an "alternative-fueled vehicle" is either designed or manufactured by an original equipment manufacturer or is a converted vehicle designed to operate in either dual-fuel, flexible-fuel, or dedicated modes on fuels other than gasoline or diesel. This does not include a conventional vehicle that is limited to operation on blended or reformulated gasoline fuels.

SCHEDULE 2, PART B: ENERGY SOURCES AND DISPOSITION

Enter the annual megawatt hours (MWH) for all sources of electricity and disposition of electricity listed.

For line 1, **Net Generation**, enter the net generation (gross generation minus station use) from all respondent-owned plants. If a plant is jointly owned, enter only the reporting party's share of generation.

Include generation used to replace system losses arising from wheeling transactions. Include net generation supplied as part of a tolling arrangement.

For line 2, **Purchases from Electricity Suppliers**, enter the total amount of energy purchased from electricity suppliers including: nonutility power producers and power marketers (reported separately in previous years), municipal departments and power agencies, cooperatives, investor-owned utilities, political subdivisions, state agencies and power pools, and marketing agencies of the United States Government and Canada; these agencies include Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), Western Area Power Administration (WAPA), Tennessee Valley Authority (TVA), United States Army Corps of Engineers, the United States Bureau of Reclamation, United States Bureau of Indian Affairs, International Boundary and Water Commission, Hydro-Quebec, etc. This entry includes requirements power, firm power, and all other non-firm service. Note: Please identify on Schedule 9, Footnotes, the portion of purchased power obtained through tolling arrangements and international purchases.

For line 3, **Exchanges Received (In)**, enter the amount of exchange energy received. Do not include power received through tolling arrangements.

For line 4, **Exchanges Delivered (Out)**, enter the amount of exchange energy delivered. Do not include power delivered as part of a tolling arrangement.

For line 5, **Exchanges (Net)**, enter the net amount of energy exchanged. Net exchange is the difference between the amount of exchange received and the amount of exchange delivered (lines 3 and 4). This entry should not include wholesale energy purchased from or sold to regulated companies or unregulated companies for other systems.

For line 6, **Wheeled Received (In)**, enter the total amount of energy entering your system from other systems for transmission through your system (wheeling) for delivery to other systems. Do not report as Wheeled Received, energy purchased or exchanged for consumption within your system, which was wheeled to you by others.

For line 7, **Wheeled Delivered (Out)**, enter the total amount of energy leaving your system that was transmitted through your system for delivery to other systems. If Wheeling Delivered is not precisely known, please estimate based on your system's known percentage of losses for wheeling transactions.

For line 8, **Wheeled (Net)**, enter the difference between the amount of energy entering your system for transmission through your system and the amount of energy leaving your system (line 6 minus line 7). Wheeled net represents the energy losses on your system associated with the wheeling of energy for other systems.

For line 9, **Transmission by Others, Losses**, enter the amount of energy losses associated with the wheeling of electricity provided to your system by other utilities. Transmission by Others, Losses should always be expressed as a negative value.

For line 11, **Sales to Ultimate Customers**, enter the amount of electricity sold to customers purchasing electricity for their own use and not for resale. This entry should correspond to the revenue from sales to ultimate customers reported on Schedule 2 Part C, line 1, and should be equal to the total megawatt hours reported on Schedule 4, Parts A, B and D, when summed for all reported states.

For line 12, **Sales for Resale**, enter the amount of electricity sold for resale purposes. This entry should include sales for resale to power marketers (reported separately in previous years), full and partial requirements customers, firm power customers, and non-firm customers. This entry should also correspond to the revenue from sales for resale reported in Schedule 2 Part C, line 3. Note: Please identify on Schedule 9, the portion of sales for resale power sold through tolling arrangements and any international sales.

For line 13, **Energy Furnished without Charge**, enter the amount of electricity furnished by the electric utility without charge, such as to a municipality under a franchise agreement or for public street and highway lighting. This entry does not include data entered in line 14.

For line 14, **Energy Consumed by Respondent without Charge**, enter the amount of electricity used by the electric utility in its electric and other departments without charge. This entry does not include data entered in line 13.

For line 15, **Total Energy Losses**, enter the total amount of electricity lost from transmission, distribution, and/or unaccounted for. This is the difference between line 10, "Total Sources," and the sum of lines 11, 12, 13, and 14. Total Energy Losses should always be expressed as a positive value.

SCHEDULE 2, PART C: ELECTRIC OPERATING REVENUE

All electric operating revenue data should be rounded to the nearest tenth and reported in thousand dollars; for example, revenue of \$8,461,688.42 should be reported as 8,461.7 (thousand dollars).

For line 1, **Electric Operating Revenue from Sales to Ultimate Customers**, enter the amount of revenue from sales of electricity to those customers purchasing electricity for their own use and not for resale. Revenue reported on Schedule 4C, for delivery service (and all other charges) should not be reported on Schedule 2C, line 1, but should be reported in Schedule 2C, line 2, **Revenue from Unbundled (Delivery) Customers**. Revenue entered on line 1 is gross revenue and includes the revenue from state and local income taxes, energy or demand charges, customer service charges, environmental surcharges, franchise fees, fuel adjustments and other miscellaneous charges applied to end-use customers during normal billing operations. Revenue entered on line 1 should not include deferred charges, credits, or other adjustments, such as fuel or revenue from purchased power, from previous reporting periods which are included in Schedule 2C, line 4, **Electric Credits/ Other Adjustments**. Revenue entered on line 1 should correspond to electricity sales reported in Schedule 2B, line 11. (Revenue entered on line 1 should also be the same total revenue reported on Schedule 4, column e (**Total**) for Parts A, B, and D, when summed for all reported states). Revenue entered on line 1 should include all unbilled revenue resulting from power sold during the reporting period.

For line 2, **Revenue from Unbundled (Delivery) Customers**, enter the amount of revenue from unbundled customers who purchase their electricity from a supplier other than the electric utility that distributes power to their premises. This electric operating revenue does not include the charges for electric energy but does include the revenue required to cover power delivery. Revenue entered on line 2 should be the same total revenue reported on Schedule 4C, column e, when summed for all states.

For line 3, **Electric Operating Revenue from Sales for Resale**, enter the amount of revenue from sales of electricity sold for resale purposes. This entry should include revenue from sales for resale to wholesale or retail power marketers, full and partial requirements customers (firm), and to no requirements (non-firm) customers. This entry should also correspond to the sales for resale reported in Schedule 2B, line 12.

For line 4, **Electric Credits/Other Adjustments**, enter the amount of deferred revenue, which corresponds to Account 449.1 of the Uniform System of Accounts including revenue not applied to end- use or resale customers during the normal billing cycle. Funds included in this entry consist of refunds to customers resulting from rate commission rulings delayed beyond the reporting year in which the funds were originally collected. Also, include revenue distributions to customers from rate stabilization funds where the distribution occurred during the current reporting year, but the funds were collected during previous reporting years.

For line 5, **Revenue from Transmission**, enter the amount of revenue derived from the transmission of electricity for others (wheeling).

For line 6, **Other Electric Operating Revenue**, enter the amount of revenue received from electric activities other than selling electricity. This may include revenue from selling or servicing electric appliances, revenue from the sale of water and water power for irrigation, domestic, industrial or hydroelectric operations, revenue from electric plants leased to others, revenue from the sale of steam, but not including sales made by a steam heating department or transfers of steam under joint facility operations, revenue from interdepartmental rents or sale of electric property, revenue from late fees, penalties or reconstructions, and revenue from interest.

SCHEDULE 3, Part A: DISTRIBUTION SYSTEM INFORMATION

For purposes of this schedule, a distribution circuit is any circuit with a voltage of 35kV or below that serves end use customers directly or through step-down transformers or substations. Circuits that are operated in a closed-looped manner, i.e. not operated radially, are called 'networked'. Networks serve key downtown or metropolitan customers. Networks also provide sub-transmission supply to other distribution circuits through step-down transformers or substations. During outages to one or more network circuits, the customers are automatically served by other network circuits with no interruption. For network primary systems, the circuit count includes all circuits that supply the network. Where a circuit with a voltage of 35 kV or below is a source for lower voltage circuits through step-down transformers or substations, the circuits at the higher voltage and the lower voltage are included in the circuit count. Report this schedule if you own distribution lines.

Volt/VAR Optimization (VVO) is a process used by electric distribution companies to actively manage voltage levels and reactive power on distribution circuits in order to reduce energy losses and improve reliability and power quality. VVO is typically achieved through the use of real-time information and controls that activate capacitor banks, voltage regulators, and transformer load tap changers - and in some cases, distributed generation to adjust voltage and VAR levels on the primary and secondary distribution circuits.

On line 1 enter the Total Number of Distribution Circuits.

On line 2 enter the Total Number of Distribution Circuits that employ voltage/VAR optimization (VVO).

SCHEDULE 3, Part B: DISTRIBUTION SYSTEM RELIABILITY INFORMATION - IEEE

If your entity calculates system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) and determines Major Event Days in accordance with the IEEE 1366-2003 or IEEE 1366-2012 standard, answer 'yes' to questions 1 and 2 and complete Part B. If your entity calculates SAIDI and SAIFI via another method answer 'yes' to question 1 and no to question 2 then skip Part B and complete Part C. If your entity does not calculate SAIDI and SAIFI answer 'no' to question 1 and go to Schedule 4A. For lines 3 through 6 complete all that you calculate; for example, if you only calculate SAIDI and SAIFI without Major Event Days included, complete the area under the subtitle "Excluding Major Events" and do not complete the area under the subtitle "Including Major Events".

The **system average interruption frequency index, or SAIFI**, indicates how often the average customer experiences a sustained interruption (of over 5 minutes) over a predefined period of time. In this schedule report annual SAIFI, or the SAIFI resulting from all interruptions in the reporting year. SAIFI is calculated as the sum over the year of total number of customers that experienced an interruption of more than 5 minutes, divided by the total number of customers.

SAIFI = [Sum of total number of customers interrupted over the year] / [Total number of customers served]

The **system average interruption duration index, or SAIDI**, indicates the total duration of interruption for the average customer over a predefined period of time. In this schedule report annual SAIDI, or the SAIDI resulting from all interruptions in the reporting year. SAIDI is calculated as the sum over the year of all customers interrupted for more than 5 minutes times the number of minutes they experienced an interruption, divided by total number of customers.

SAIDI = [Sum of customer minutes interrupted over the year] / [Total number of customers served]

On lines 3 through 6 report the values that you calculate.

- Report the Annual Distribution SAIDI Including Major Event Days on line 3,
- Report the Annual Distribution SAIDI Excluding Major Event Days on line 3,
- Report the Annual Distribution SAIDI Including Major Event Days excluding events where the reliability event was initiated from loss of supply (e.g. resulted from an event on the distribution system, not from the high-voltage system) the Annual Distribution SAIDI Excluding Major Event Days excluding events where the reliability event was initiated from loss of supply on line 4.
- Report the Annual Distribution SAIFI Including Major Event Days on line 5,
- Report the Annual Distribution SAIFI Excluding Major Event Days on line 5,
- Report both the Annual Distribution SAIFI Including and Excluding Major Event Days excluding events where the reliability event was initiated from loss of supply on line 6.

On line 7, enter the **Total number of customers used to calculate SAIDI and SAIFI**, as reported on this schedule. A customer is defined as a metered electrical service point for which an active bill account is established at a specific location (e.g., premise). (IEEE 1366-2003 pg. 2)

On line 8, **indicate the voltage at which you distinguish the distribution system from the supply system.**

On line 9, indicate whether your company has an outage management system that detects loss of load or customer outages. Answer "yes", even if you also receive outage information manually via other methods.

SCHEDULE 3, PART C: DISTRIBUTION SYSTEM RELIABILITY INFORMATION – OTHER**SAIDI and SAIFI calculations via other methods, calculated by state**

On lines 10 through 11 report the values that you calculate.

- Report the Annual Distribution SAIDI Including major events on line 10,
- Report the Annual Distribution SAIDI Excluding major events on line 10,
- Report the Annual Distribution SAIFI Including major events on line 11,
- Report the Annual Distribution SAIFI Excluding major events on line 11.

On line 12, enter the total number of customers used to calculate SAIDI and SAIFI, as reported on this schedule.

On lines 13, indicate whether your utility includes inactive accounts in its definition of customers used to determine SAIDI and SAIFI.

On line 14, indicate how your utility defines momentary outages, i.e., less than how many minutes. Outages can be classified as either momentary or sustained. Momentary outages are not included in determining SAIDI and SAIFI.

On line 15, report the voltage that you use to distinguish the distribution system from the supply system.

On line 16, indicate whether your company has an outage management system that detects loss of load or customer outages. Answer “yes”, even if you also receive outage information manually via other methods.

SCHEDULE 4, PART A: SALES TO ULTIMATE CUSTOMERS. FULL SERVICE – ENERGY AND DELIVERY SERVICE (BUNDLED)

The table below should be used as a guide for the classification of your end-use customers; pay close attention to how your consumers should be organized based on our four Sectors: Residential, Commercial, Industrial, and Transportation. Please note that data for the Transportation Sector (see definitions) has replaced the “Other” Sector on all parts of Schedule 4. Non-Transportation customers previously reported under “Other,” including street and highway lighting, should now be included in the Commercial Sector.

Irrigation customers should be reported in the Industrial Sector.

Enter the reporting year revenue (thousands of dollars, to the nearest tenth), megawatt hours, and number of customers for sales of electricity to ultimate customers by state, balancing authority, and customer class category for whom your company provides both energy and delivery service. Power marketers providing both energy and delivery service should report on Part D. Note: For sales to customer groups using brokers or aggregators, continue to count each customer separately. For instance, count a group of franchised commercial establishments aggregated through a single broker as separate customers (as reported in prior years). Using the drop-down menus, enter the 2-letter U.S. Postal Service abbreviation for the state and the balancing authority in which the electric sales occurred. Select the check box to indicate whether your rates are decoupled. If you select “Yes,” indicate whether the revenue adjustment is automatic or requires a rate making proceeding. Entities completing this Schedule are also required to complete Schedule 6 Part D, Advanced Metering and Customer Communications.



The residential sector includes private households and apartment buildings where energy is consumed primarily for: • space heating • water heating • air conditioning • lighting • refrigeration • cooking • clothes drying	The commercial sector includes nonmanufacturing business establishments such as: • hotels • motels, • restaurants • wholesale businesses • retail stores • health, social, and educational institutions • public street and highway lighting • crypto mining and data centers • municipalities • divisions or agencies of states and federal governments under special contracts or agreements, and other utility departments, as defined by the pertinent regulatory agency and/or electric utility
The industrial sector includes: • manufacturing • construction • mining • agriculture (irrigation), • fishing • forestry establishments	The transportation sector includes: • railroads and railways (The fuel source of propulsion must be electrical like a metro system which exists in large cities. Please count number of systems not meters.)

SCHEDULE 4, PART B: SALES TO ULTIMATE CUSTOMERS ENERGY-ONLY SERVICE (WITHOUT DELIVERY SERVICE)

Enter the reporting year revenue (thousands of dollars, to the nearest tenth), megawatt hours, and number of customers for sales of electricity to ultimate customers by state, by balancing authority, and customer class category for which your company provides only the energy consumed, where another electric utility provides delivery services, including, for example, billing, administrative support, and line maintenance.

SCHEDULE 4, PART C: SALES TO ULTIMATE CUSTOMERS DELIVERY-ONLY SERVICE (AND ALL OTHER CHARGES)

Enter the reporting year revenue (thousand dollars, to the nearest tenth), megawatt hours delivered, and number of customers for sales of electricity to ultimate customers in your service territory by state by balancing authority and customer class category for which your company provides only billing and related energy delivery services, where another company supplies the energy. Entities completing this Schedule are also required to complete Schedule 6 Part D, Advanced Metering and Customer Communications.

SCHEDULE 4, PART D: SALES TO ULTIMATE CUSTOMERS. BUNDLED SERVICE (ENERGY SERVICE PROVIDERS AND POWER MARKETERS)

Note: typically, the only entities that report on Schedule D are Texas Energy Service Providers. Any other entity that believes it should report on Schedule D should first contact the EIA Survey Support Team at eia4usa@eia.gov

Enter the reporting period revenue (thousands of dollars, to the nearest tenth), megawatt hours, and number of customers for sales of electricity to ultimate customers by state, by balancing authority, and customer class category for whom your company provided both energy and delivery service. For public street and highway lighting, count all poles in a community as one customer. Note: For sales to customer groups using brokers or aggregators, continue to count each customer separately. For instance, count a group of franchised commercial establishments aggregated through a single broker as separate customers (as reported in prior years). Enter the two-letter U.S. Postal Service abbreviation (if not preprinted) for the state in which the electric sales occur. (Note: Texas Energy Service Providers (ESPs) should include delivery revenues.)

Common Instructions: SCHEDULE 4. PARTS A, B, C, AND D

For the on-line form, when adding a new state and/or balancing authority, the state must be entered first, from the drop down menu and then the balancing authority must also be selected from the drop down menu. All new states or balancing authorities must be added to Schedule 4 before they can be added to a subsequent schedule.

For column a, **Residential**, enter the revenue, megawatt hours, and number of customers for electric energy supplied for residential (household) purposes. For the residential class, do not duplicate the customer accounts due to multiple metering for special services (e.g., water heating, etc.).

For column b, **Commercial**, enter the revenue, megawatt hours, and number of customers for electric energy supplied for commercial purposes.

For column c, **Industrial**, enter the revenue, megawatt hours, and number of customers for electric energy supplied for industrial purposes.

For column d, **Transportation**, enter the revenue, megawatt hours, and number of customers for electric energy supplied for transportation purposes.

SCHEDULE 5: MERGERS AND/OR ACQUISITIONS

If a merger or acquisition has occurred during the reporting period, report those newly acquired corporate entities whose operations are now included in this report.

SCHEDULE 6: DEMAND-SIDE MANAGEMENT AND SMART GRID INFORMATION

Demand-side management (DSM) programs, both energy efficiency programs and demand response programs, are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Schedule 6 is divided into four parts:

- Part A, Energy Efficiency Programs,
- Part B, Demand Response Programs,
- Part C, Dynamic Pricing Programs,
- Part D, Advanced Metering and Customer Communications

SCHEDULE 6, Part A: Energy Efficiency Programs

The reporting entity depends on who has oversight and decision-making authority over the program:

You should report for programs your company administers or if your company contracts another company to provide DSM to your customers and your company is responsible for decision making relative to that program.

You should not report for programs that are run by another entity (nonutility DSM Administrator; see further discussion immediately below) that is typically selected by an authority that provides oversight to the program. The nonutility DSM Program Administrator will provide the results of the program in this section, and your company should not do so, except as noted below:

Nonutility DSM Administrators: These are entities selected by a government organization to contract for and administer energy efficiency portfolios within a specific geographic region and or market. Administrators are typically selected by a public service commission or a non-profit or state government agency as determined by legislation.

EIA currently collects these data from the following program administrators:

- Sustainable Energy Trust Fund (DC)
- Efficiency Maine Trust
- Energy Trust of Oregon
- Focus on Energy (Wisconsin)
- NYSERDA
- Cape Light Compact
- Hawaii Energy Efficiency Program
- Delaware Sustainable Energy Utility
- NJ Clean Energy Program
- Vermont Energy Investment Corporation

If your nonutility DSM Administrator is listed above, you do not report in Schedule 6A. If your Nonutility DSM Administrator is not listed above, you will have to report new energy efficiency activities for your customers, in Schedule 6A. If you have a nonutility DSM Administrator not listed above, you may request that they be added for the next reporting year by entering that request in the comment section of the form. If your nonutility DSM administrator reports for you indicate your DSM administrator by selecting them from the drop-down list on question?

If you are a Nonutility DSM Administrator listed above, please provide a list of electric utilities for whom you provide DSM products and services, either as an attachment to this form or if submitting electronically, in the comment section.

The DSM information should:

- Reflect only new reporting year activities that are undertaken specifically in response to company-administered programs, including activities implemented by third parties under contract to the company;

- Account for the complete range of DSM programs, including energy efficiency and demand response; and
- Represent the energy and demand savings at the **customer meter** (i.e., transmission and distribution or reserve requirement savings should be excluded). Also, energy and demand savings should be reported as adjusted gross savings. **Adjusted Gross Savings** is the change in energy consumption and or demand that results directly from program-related actions taken by participants in an efficiency program regardless of why they participated. The effects that building demolition, equipment degradation, and program attrition can have on the life and savings of the efficiency measure can be included to the extent that they are easily estimated from prior similar programs or experience.

The DSM information **should exclude**, to the extent possible, energy and demand savings that are not attributable to DSM program activities. Non-program related effects include changes in energy and demand attributable to:

- Government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage;
- Natural operations of the marketplace (e.g., reductions in customer energy usage due to higher prices); and,
- Weather and business-cycle fluctuations.

Power supply cooperatives, municipal joint action agencies, and Federal Power Marketing Administrations should coordinate the reporting of DSM information with their power purchasing utilities to avoid double counting the effects and costs of DSM programs. Distribution companies should weigh the benefits of taking credit for their programs by reporting this information under their utility identification versus the convenience of having their program directors report this information in aggregate. EIA would prefer the distribution company to report the data whenever possible.

Energy efficiency measures consist of installations of more efficient devices or implementing more efficient processes that exceed current standards. An energy efficiency resource must achieve a long-term continuous reduction in demand for electricity and be available without a requirement of notice or dispatch from the grid operator.

Examples are replacing light bulbs with more efficient technology or replacing older HVAC systems with high efficiency systems that exceed current codes and standards.

This part of the schedule collects information on the energy and demand savings of a portfolio of Energy Efficiency Programs implemented, and measures installed, by major customer sector within a state and balancing authority. It is divided into five subparts:

- Reporting Year Incremental Annual Savings
- Incremental Life Cycle Savings
- Reporting Year Incremental Costs
- Incremental Life Cycle Costs
- Weighted Average Life for Portfolio (Years)

Incremental Annual Savings – Reporting Year are those changes in energy use (measured in megawatt hours) and peak load (reduction in load at the time of the annual system peak hour, measured in megawatts) caused in the current reporting year by

- new participants in DSM programs that operated in the previous reporting year, and
- participants in new DSM programs that operated for the first time in the current reporting year.

A “New program” is a program for which the reporting year is the first year the program achieved savings, regardless of when program development and expenditures began.

Annualize all Estimates: Reporting Year Incremental Annual Savings should be annualized, i.e., they should be reported as if the participants were in the program starting on Jan 1 of the reporting year and continued in the program for a full year.

Incremental Savings - Life Cycle are the estimated total changes in energy use and peak load for incremental programs and participants over the life of the programs. DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible, consider the useful life of efficiency by accounting for building demolition, equipment degradation, and program attrition.

A “Life cycle” means the number of years the program is planned to exist and includes all future anticipated savings as well as reporting year savings. The mean life of a program is measured based on the number of years that savings are expected to be achieved independent of the number of years of expenditures for any measure. Please note that **Life Cycle Savings** should be provided if **Reporting Year Annual Savings** are reported

- Incremental life-cycle energy savings (megawatt-hours): report as the lump sum total savings projected for the life cycle of the incremental programs and participants. For example, if a project has an anticipated life of 10 years with savings in each year of 10,000 MWH, report the total of 100,000 MWH.
- Incremental life cycle peak demand saving (megawatts): report the average of the annual peak demand savings for the life cycle of the incremental programs and participants. For example, if a program has a four-year life with the following pattern of demand reductions – Year 1: 10 MW, Year 2: 20 MW, Year 3: 20 MW, Year 4: 10 MW – report the average of 15 MW.

For Part A, please report for both “Reporting Year Incremental Annual Savings” and “Incremental Life Cycle Savings” under the appropriate customer sector: Residential, Commercial, Industrial, and Transportation: for Energy Efficiency,

- On Lines 1 and 3, enter the aggregate Energy Savings (megawatt hours)
- On Lines 2 and 4, the Peak Demand Savings (megawatts to one decimal point).

Costs for energy efficiency programs should be broken down into two categories, customer incentives and all other costs. Customer incentives are the total financial value provided to a customer for program participation, whether, for example, cash payment, or lowered tariff rates relative to non-participants, in-kind services (e.g. design work), or other benefits directly provided to the customer for their program participation. Reporting Year Incremental costs should include all costs for the programs for years prior to the incremental year if these costs were incurred as part of the startup of the program. Incremental life cycle costs should include all anticipated costs of the program including the Reporting Year Incremental Costs and all future costs.

Please note that **Reporting Year Incremental Costs** should be provided if **Reporting Year Incremental Annual Savings** are reported. In some cases **Reporting Year Incremental Costs and Incremental Life Cycle Costs** may be the same, due to most energy efficiency expenditures being incurred in the first year for participants. See the [861 FAQ](#) site for more details.

- For lines 5 through 8 report costs in thousands of dollars for each state, each balancing authority, and for each sector.
- For example, if a program has a life cycle of 10 years and if \$10,000 was incurred prior to the incremental year of a program for startup costs and the average cost of the program for the next ten years is \$5,000/year, the reporting year incremental costs would be \$15,000 and the incremental life cycle costs would be \$60,000. Note in this example the length in years of the program (10 years based on the number of years of savings) is one less year than the years of expenditures (11 years). The number of years of program savings is used to determine the life of the program.

Weighted Average Life for Portfolio (Years) – Please use the Excel spreadsheet (press the ‘Calculate’ button to call up the template) to determine the weighted average life of your portfolio of EE programs or measure - by state, balancing authority, and sector on 6A, line 10. Weighted Average Life for portfolio of Energy Efficiency activities or measures should include all measures that are reporting in lines 1 through 4. On the spreadsheet enter your program or measure number, the total life

cycle savings in MWH for each incremental program and its associated life in years. The life in years should be estimated as the mean life of the measure. Once all your programs have been entered the spreadsheet will return the weighted average life for the portfolio. This spreadsheet should be used for each state balancing authority, and sector. These averages may be used to estimate the economic value of the energy efficiency portfolio in total and is a key metric to the economic comparison of energy efficiency activities and other options.

SCHEDULE 6, PART B: DEMAND RESPONSE PROGRAMS

Demand Response Programs are procedures that encourage a temporary reduction in demand for electricity at certain times in response to a signal from the grid operator or market conditions. Examples are the dimming of lights, turning on backup generators or shutting down industrial processes. Demand Response program reporting should be broken down by state, balancing authority, and customer class.

Potential peak demand savings refers to the total demand savings that could occur at the time of the system peak hour assuming all demand response is called.

Actual peak demand savings is demand reduction actually achieved by demand response activities and is measured at the time of the company's annual system peak hour.

On line 1 enter the number of customers participating in the Demand Response programs.

On line 2 enter the energy savings in MWH by customer sector.

On line 3 enter the potential peak demand savings in MWs for demand response programs.

On line 4 enter the actual peak demand savings in MWs for demand response programs.

On line 5 enter the total customer incentives in thousands of dollars.

On line 6 enter all other costs to run the Demand Response program; these are in thousands of dollars.

On line 7 enter the number of grid-enabled water heaters (as defined in 10 CFR Part 430) that you added to your program this year. A grid interactive water heater is an electric storage water heater that is capable of being controlled remotely by a third party (usually an electricity service provider) that provides the third party the ability to control the operation of the unit by storing thermal energy during off-peak times. DOE's Office of Energy Efficiency and Renewable Energy is in the process of issuing a final rule for efficiency standards for residential water heaters. Once those standards are finalized, EIA will, if necessary, adjust the definition above to be in accordance with the minimum efficiency standards for grid-enabled water heaters.

SCHEDULE 6, PART C: DYNAMIC PRICING PROGRAMS

Dynamic pricing programs (also known as time-based rate programs) are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Report those customers that are enrolled in the program and are billed accordingly whether or not they are active participants. For each state, balancing authority, and customer sector, report the number of customers enrolled in dynamic pricing programs.

Time of Use Prices (TOU) is a program in which customers pay different prices at different times of the day. On-peak prices are higher and off-peak prices are lower than a "standard" rate. Price schedule is fixed and predefined, based on season, day of week, and time of day.

Real Time Pricing (RTP) is a program of rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Variable Peak Pricing (VPP) is a program in which a form of TOU pricing allows customers to purchase their generation supply at prices set on a daily basis with varying on-peak and constant off-peak rates. Under the VPP program, the on-peak price for each weekday becomes available the previous day (typically late afternoon) and the customer is billed for actual consumption during the billing cycle at these prices.

Critical Peak Pricing (CPP) is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by imposing a pre-specified high rate or price for a limited number of days or hours. Very high "critical peak" prices are assessed for certain hours on event days (often limited to 10-15 per year). Prices can be 3-10 times as much during these few hours. Typically, CPP is combined with a TOU rate, but not always.

Critical Peak Rebate (CPR) is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by providing a rebate to the customer on a limited number of days and for a limited number of hours, at the request of the energy provider. Under this structure the energy provider can call event days (often limited to 10-15 per year) and provide a rebate typically several times the average price for certain hours in the day. The rebate is based on the actual customer usage compared to its baseline to determine the amount of the demand reduction each hour.

On line 1, enter the number of customers participating in dynamic pricing programs, by customer class.

On line 2, for each customer sector indicate if customers in this sector are participating in Time-of-Use Pricing.

On line 3, for each customer sector indicate if customers in this sector are participating in Real Time Pricing.

On line 4, for each customer sector indicate if customers in this sector are participating in Variable Peak Pricing

On line 5, for each customer sector indicate if customers in this sector are participating in Critical Peak Pricing.

On line 6, for each customer sector indicate if customers in this sector are participating in Critical Peak Rebate.

SCHEDULE 6, PART D: ADVANCED METERING AND CUSTOMER COMMUNICATIONS

Entities providing data on Schedule 4 Part A and/or C are required to complete Schedule 6 Part D.

Standard Electric Meters (non AMI/AMR meters) are electromechanical or solid state meters measuring aggregated kWh where data are manually retrieved over monthly billing cycles for billing purposes only. Standard meters may also include functions to measure time-of-use and/or demand with data manually retrieved over monthly billing cycles.

Automated Meter Reading (AMR): Meters that collect data for billing purposes only and transmit this data **one way**, usually from the customer to the distribution utility. Aggregated monthly kWh data captured on these meters may be retrieved by a variety of methods including drive-by vans with short-distance remote reading capabilities and communication over a fixed network such as a cellular network. Enter the state and balancing authority and report the total number of AMR meters by sector.

Advanced Metering Infrastructure (AMI): Meters that measure and record usage data at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and

other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in **two-way** communication capable of recording and transmitting instantaneous data.

Installed AMI with home area network (HAN) gateway enabled should be reported as a subset of AMI (see number 4 above). In this case, a HAN consists of software and hardware components residing within an AMI meter that permits the meter to communicate with devices within a customer's premises.

Energy Served through AMI (MWH) should be entered in megawatt hours for customers served and should not be greater than the combined total sales reported on Schedule 4 Part A and/or C

Direct Load Control: A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

Enter the state and balancing authority and on line 1 enter the number of AMR meters, by customer class.

On line 2 enter the number of AMI meters, by customer class.

On line 3 enter the number of AMI meters with home area network (HAN) gateway enabled, by customer class.

On line 4 enter the number of standard (non-AMR/AMI) meters, by customer class.

Line 5 auto-sums the total number of meters (All Types), by customer class.

On line 6 enter the energy served (megawatt hours) through AMI meters, by customer class.

On line 7 enter the number of customers able to access daily energy usage through a web portal or other electronic means.

On line 8 enter the number of customers with direct load control, by customer class. Please note that EIA is asking for customers and not meters, so the reported number shall not exceed what was stated on 4A and 4C combined.

SCHEDULE 7, PART A: NET METERING PROGRAMS

Net Metering tariff arrangements permit a facility, typically generating electricity from a renewable resource (using a meter that reads inflows and outflows of electricity) to sell excess power generated over its load requirement back to the electrical grid, typically but not necessarily at a rate equivalent to the retail price of electricity.

Virtual Net Metering: A billing arrangement that allows multiple energy customers to receive net metering credit from a shared onsite or remote renewable energy system as if it was located behind the customer's own meter. Generally, but not always virtual net metering programs have two primary business partners. One is the solar developer or operator, that sells a fraction (or all) of the system (usually measured in capacity or shares) to the ultimate customer(s) and an electric distribution company that bills the customer(s) for its energy use and provides a credit on the customer's bill for the generation allocated to its share of the resource. In some cases the distribution company serves in both of these roles.

For all net metering applications, report the installed net metering capacity by state, balancing authority, customer class and technology. Capacity for PV solar should be reported in MW AC or in DC. Capacity for wind and other technologies should be reported in MW as AC load capable. All of which should be reported to the nearest 0.001 MW. Example: 8 kW should be 0.008 MW.

Report the number of net metering installations/customers that are actively enrolled in a net metering program as of December 31st of the data year. Customer count/ installation by technology should not exceed the values in Schedule 4 Parts A and C, combined. For each program technology type and sector, if you complete installed capacity or number of installations/customers then you will need to complete both lines of data.

For PV solar installations also report the number of virtual net metered customers and the capacity of virtual net metering programs both for programs from resources that are less than one MW and resources that are 1 MW or greater. All three programs, net metering, virtual net metering below 1 MW and virtual net metering above 1 MW should be mutually exclusive, meaning all three are added together to get the total. For example if you report capacity in net metering you would not report that capacity for the same installation in virtual net metering. If the installation is not part of a net- metering or virtual net metering agreement, the installation if under 1 mw would be reported in Schedule 7B Non-net metered Distributed Generators.

For virtual net metering, the capacity should be reported based on which customer class/sector has the virtual net metering agreement, not the physical location of the generator(s).

In addition, report the amount of known storage associated with the PV net metering installations, **if available**.

If the data is available, enter the amount of electric energy sold back to the utility (**MWh**) through the net metering application.

SCHEDULE 7, PART B: NON NET-METERED DISTRIBUTED GENERATORS

Dispersed generator data is no longer collected on the EIA-861.

Schedule 7, Part B is intended to collect information about generators that are NOT reported on Form EIA-860, “Annual Electric Generator Report.” Plants with a capacity of 1 MW or greater which ARE grid-connected, meet the threshold criteria for reporting on the Form EIA-860 and as such, need not be reported on Schedule 7B of Form EIA-861. **Also, Schedule 7B is intended to collect information about generators that are NOT reported in Schedule 7A (Net Metering).** Therefore, if the generator data has been reported in Schedule 7A, DO NOT include it under Schedule 7B, but include generators other than those that are net metered.

This schedule now collects information from distribution companies by sector (residential, industrial, commercial and transportation) on generators of less than 1 megawatt (1000 kilowatts) installed at or near a customer’s site, or other sites within the system. Provide actual data if available, otherwise provide best estimates.

NUMBER AND CAPACITY

For line 1, **Number of generators**, provide the number of distributed generators in the area served by your distribution system, by state, by balancing authority. (**Less than 1 megawatt**)

For line 2, **Total combined capacity**, provide the nameplate capacity (to the nearest thousandths) **for all generators with less than 1 megawatt** that reported on line 1.

For line 3, capacity that consists of **backup-only units**, provide the total nameplate capacity of generators that are used **only** for emergency backup service.

For Line 4, capacity owned by respondent, provide the total nameplate capacity listed in line 2 that the respondent owns.

CAPACITY BY TECHNOLOGY AND SECTOR

For each of the technologies listed in lines 5 through 13, provide the capacity and sector. The total of lines 5 through 13 (line 14) should equal the total combined capacity in line 2.

Storage should be included if available.

Direct Connected is for installations that are not located at an ultimate customer's site but are in front of the meter and/or connected directly to a distribution system.

SCHEDULE 8: SERVICE TERRITORY INFORMATION

Please verify the names of the counties, parishes, etc. (provided by EIA in a drop-down menu), by state, where your utility-owned distribution system's electrical equipment is located. The information may have been reported by the respondent last year or the result of independent research by the EIA staff processing the Form EIA-861. If the information is incorrect, please provide the correct information in Schedule 9.

SCHEDULE 9: FOOTNOTES

This schedule provides additional space for comments. For clarification purposes, identify schedule, part, line number and column (if applicable) for each comment.

GLOSSARY

The glossary for this form is available online at the following URL: <http://www.eia.gov/glossary/index.html>