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## **Regional Reliability Reference Criteria A-10 Classification of Bulk Power System Elements**

Task Force on Coordination of Planning Revision Review Record:
December 1, 2009
March 27, 2020

Adopted by the Members of the Northeast Power Coordinating Council Inc., this April 28, 2007 on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

## Revision History

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking (New, Errata or Revisions)</b>
0	April 28, 2007	Initial release	New
1	December 1, 2009	TFCP Review	Revision
2	March 27, 2020	TFCP/CP-11 Review	Revision. (Refer to Technical Rationale attachment for details of changes.)
3	May 6, 2020	TFCP Errata	Errata correction Page 12 Section 4.1

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## 1. Introduction

### 1.1 Title: Classification of Bulk Power System Elements

### 1.2 Criteria: A-10

### 1.3 Objective:

NPCC defines specific requirements applicable to the design, operation, and **protection** of the **Bulk Power System**. The object of this *Classification of Bulk Power System Elements* (Document A-10) is to provide the methodology to identify the **bulk power system elements** or parts thereof, of the interconnected NPCC Region, for NPCC criteria applicability.

The methodology is based on the following:

- An established set of performance requirements shall be used to identify **bulk power system buses** and **elements**.
- *Bus*-based power system simulation analysis shall be used to demonstrate system performance.
- Identification of **bulk power system elements** from identification of the **bulk power system buses**.
- An element-by-element exclusion methodology may be used to determine **elements** that are excluded from Directory 1 applicability.
- **Elements** shall not be included in the **bulk power system** based on voltage class alone.
- *Buses* and **elements** shall be evaluated based on this methodology when changes occur on the system that could change either's **bulk power system** status; the evaluation may be limited to the affected part of the system.
- A periodic comprehensive re-assessment of *bus* status and **element** exclusions shall be performed at least once every five years.

**Areas** and facility owners may adopt methodologies that exceed the requirements set forth in this document for their own purposes. However, only **elements** classified as **bulk power system** as a result of testing described in this document shall be included on the NPCC **Bulk Power System** List. NPCC criteria and compliance monitoring shall consider only the system **elements** identified on the NPCC **Bulk Power System** List.

The methodology is intended to be a classification test, and not a planning or operational criterion. This criteria document shall not be construed to prohibit operation in a state that is not studied in the classification testing, or in a state where an uncleared three-phase **fault** would lead to unacceptable impacts outside of the **Area**.

## 2. A-10 Defined Terms

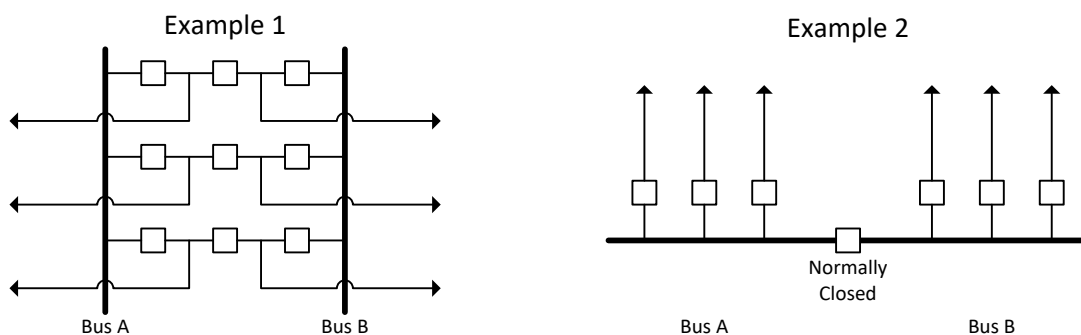
Terms in bold typeface are defined in the NPCC Glossary of Terms.

Terms in italics in this document are defined in the following section. These terms use the definitions set forth below, however, the definitions are not NPCC Glossary of Terms definitions.

### 2.1 Bus

Within this document the term *bus* refers to a junction with sensing or **protection** equipment within a substation or switching station at which the terminals of two or more **elements** are connected, regardless of whether circuit breakers are provided. In this context, *bus* may not have a direct correlation to the use of this term in substation design or a power flow data set.

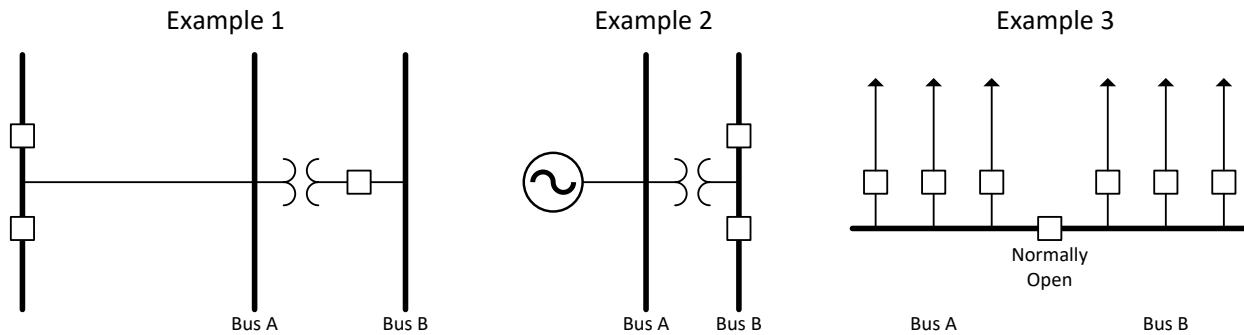
Multiple physical buses connected by normally closed circuit breakers are considered to be one *bus*, for the purpose of A-10 testing. In some configurations a *bus* may include more than one physical bus, such as in a breaker-and-a-half arrangement or a single-line-single-breaker arrangement in which two physical buses are connected through a bus-tie breaker. The examples in Figure 1 depict two possible configurations where two physical buses are tested as a single *bus*. Buses that are separated by normally open bus-tie breakers are considered as separate *buses*. The termination of line sections through switches should not be considered as a *bus* requiring testing unless the switches are activated as part of a **protection system** for the line which they sectionalize as part of normal **protection system** actions.



**Figure 1 – Configurations where Bus A and Bus B are tested as one *bus*.**

In some configurations **elements** may not be terminated to the *bus* through circuit breakers, such as the generator *bus* for a unit connected generator or a *bus* between a transmission line and transformer that are switched as a single circuit. The examples in Figure 2 depict three possible configurations where two physical buses are tested as separate *buses*.





**Figure 2 – Configurations where Bus A and Bus B are tested as two separate *buses*.**

## 2.2 Uncleared locally

Within this document, the phrase *uncleared locally* is used to denote failure of the **protection systems** including **Special Protection Systems (SPS)** at the *bus* under test to initiate tripping of all associated interrupting devices regardless of their location.

Protection located at other *buses* is assumed to operate as designed when that **protection** cannot be disabled by failure of a single **component** in common with the **protection** at the *bus* under test. Any **fault** clearing at the remote *buses* that involve communication from the *bus* under test is assumed to be inoperative. For example, consider the case where the **protection** for **elements** connected to higher voltage level and lower voltage level *buses* in the same station share a DC source, and an independent DC source is provided for the second **protection groups** associated with **elements** connected to the higher voltage level *bus*. In this case, it is acceptable when testing the lower voltage level *bus* to assume correct operation of any **protection groups** associated with **elements** connected to the higher voltage level *bus* capable of detecting the **fault** and supplied by the independent DC source.

In cases where circuit breakers are not provided at the terminals of the **element** at the *bus* under test (as shown in Figure 2 Example 1 & Example 2, *bus A*), *uncleared locally* includes a failure to clear a **fault** by circuit breakers located at any other *bus* within the same substation where the **protection** can be disabled by failure of a single **component** in common with the sensing or **protection** at the *bus* under test, unless back-up **protection** at that other *bus* using an independent DC source would detect the **fault** and initiate clearing.

For a 3-phase **fault** applied at the *bus* under test that is *uncleared locally*, fast clearing portions of Directional Comparison Blocking (DCB) schemes at the remote terminals of **elements** connected to the *bus* under test are assumed to be inoperative (reference Attachment A – Technical Rationale 2).

### 3. Classification of Bulk Power System Buses

This section provides the methodology used to identify and classify **Bulk Power System buses**.

#### 3.1 System Conditions

Prior to the commencement of an **Area**-wide assessment of **bulk power system** classification, the **Area** shall present a scope of the assessment to the NPCC Task Force on System Studies (TFSS). This presentation shall demonstrate that the study aligns with the conditions listed below. Subsequent **bulk power system** assessments of a portion of the **Area** may use the same system conditions previously presented to the TFSS, with any changes required to reflect the purpose of the assessment.

Modeling of neighboring systems should be based on the latest information available at the time of study, such as Multi-regional Modeling Working Group base cases.

##### 3.1.1 Load Levels

Each **Area** shall test at least two **load** levels for **bulk power system** classification: a seasonal peak case (the season forecasted to have the highest **load** in the **Area** under test) and a light **load** case. The seasonal peak **load** case shall model a **load** level greater than or equal to the **Area's** 50/50 seasonal peak **load** forecast, and the light **load** case shall model a **load** level at or near minimum **load** conditions, such as early morning **load** levels. Testing may be performed at other **load** levels to identify additional **bulk power system buses**.

##### 3.1.2 Major Interface Transfer Levels

Each **Area** shall determine a list of its major intra-**Area** interfaces, including the direction(s) of flow. A determination on whether an inter-NPCC-**Area** interface, including the direction(s) of flow, is major shall be made jointly between the NPCC **Areas** on either side of the interface. A determination on whether an interface between an NPCC **Area** and a non-NPCC area, including the direction(s) of flow, is major shall be made by the NPCC **Area**. Coordination with non-NPCC areas in this determination is encouraged.

Transfers on major inter- and intra-**Area** interfaces shall be set such that at least one base case, at any **load** level, contains transfers at or above the 98<sup>th</sup> percentile of flow (in other words, flows not exceeded more than 2% of the time) based on all hours of the year. It is recommended, but not required, that the peak **load** base case reflect interface transfers at or above the 98<sup>th</sup> percentile of flows during peak **load** hours, and that the light **load** base case reflect interface transfers at or above the 98<sup>th</sup> percentile of flows during light **load** hours<sup>1</sup>. In the event that a

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<sup>1</sup> Peak **load** hours and light **load** hours may either be determined by total **Area**-wide **load** levels (for example, peak **load** hours could be defined as "hours with **load** above 20,000 MW") or by times during which these **loads** often

certain direction of flow on an interface could be impactful, but flow in that direction is uncommon enough that a 98<sup>th</sup> percentile measure is not meaningful, the interface flow in that direction may be stressed at the discretion of the **Area** performing the test.

When calculating 98<sup>th</sup> percentile flows, the **Area** shall use historical data that includes a sufficient number of years to mitigate the effect of any unusual temporary conditions that may have occurred during the time period (for example, a lengthy generation outage for refurbishment). At a minimum, three years of data should be used. The 98<sup>th</sup> percentile of flows may be adjusted for known material system changes (for example, transmission or generation additions or retirements).

It is understood that it may not be possible to simultaneously stress all interfaces to the 98<sup>th</sup> percentile in a single base case. In this situation, it is expected that certain major interfaces will be stressed below the 98<sup>th</sup> percentile in certain base cases. At a minimum, each *bus* shall be tested in the base case that is most critical to the *bus*'s classification.

### 3.1.3 Generation Dispatch

Given the transfer conditions for a particular base case, the generation dispatch shall represent credible generation dispatch patterns. Among the credible dispatches, more conservative dispatches with respect to the **bulk power system** classification of the *bus* under test shall be used.

### 3.1.4 Reactive Power Dispatch

The **reactive power** dispatch of generating units, static, and dynamic reactive devices shall represent credible conditions for the **load** level, transfer levels, and generation dispatch under study.

## 3.2 Testing and Modeling Assumptions

### 3.2.1 Protection and Automation Systems

- All **reclosing** shall be assumed to be inoperative.
- Operation of **SPSs**, undervoltage **load shedding** and underfrequency **load shedding** shall be modeled if the system conditions modeled in the base case match conditions where these schemes would typically operate. Any sensing or **protection** action for the above systems located at the *bus* under test shall be assumed inoperative.

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occur (for example, peak **load** hours could be defined as “hours between 12:00 and 17:00 on weekdays during June, July, and August”).

- Generic or detailed relay models shall be used to identify un-**faulted elements** that have the potential to trip, after the tripping of remote terminals of the *bus* under test.

### 3.2.2 Load Modeling

- Load models used in the **transient stability** test shall be consistent with **Area** and NPCC practices for stability studies.
- Load models used in the steady-state test shall be either constant MVA **load**, or models based on actual system testing (taking load-serving tap-changing transformer adjustment into account).

### 3.3 Performance Requirements

A *bus* is classified as part of the **bulk power system** if any of the following is observed during transient and/or steady-state testing for any one of the base cases studied:

- System instability<sup>2</sup> that cannot be demonstrably contained within the **Area** or a defined portion of the system that crosses **Areas**.
- Cascading that cannot be demonstrably contained within the **Area** or a defined portion of the system that crosses **Areas**.<sup>3</sup>
- Net loss of source or loss of **load** greater than an **Area's** threshold, if applicable.<sup>4</sup>

### 3.4 Testing Strategy

This section provides the testing strategy that is used to identify the *buses* that should be tested per the methodology provided in this document.

At a minimum, the following *buses* shall be tested:

1. All *buses* operated at 200 kV or higher.

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<sup>2</sup> Any dynamic oscillatory response shall be clearly positively damped within 30 seconds of the initiating event. Where this cannot be achieved, the response must be demonstrably contained and limited to units with

- a) Gross individual nameplate rating less than 20 MVA. Or,
- b) Gross plant/facility aggregate nameplate rating less than 75 MVA.

<sup>3</sup> Containment of cascading can be determined by examining sequential tripping caused by exceeding stability limits, voltage limits and/or transmission element loading. When cascading crosses to a neighboring **Area** or results in a neighboring **Area** being isolated from the rest of its **Interconnection**, the affected **Area** shall be consulted to determine the severity of the impact on the performance of the system in the neighboring **Area**.

<sup>4</sup> An **Area's** loss of source and/or loss of **load** threshold will be determined by each **Area** with due consideration to impacts outside of the **Area**. The threshold values or lack of threshold values shall be presented to and reviewed by the TFSS. An **Area** may have different values for various conditions studied (e.g. summer vs. winter, light vs. peak loading, etc.). When the loss of source or **load** crosses to a neighboring **Area**, the affected **Area** shall be consulted to determine the impact on the performance of the system in the neighboring **Area**.

2. For *buses* operated at voltage levels between 50 kV and 200 kV, all *buses* adjacent to a **bulk power system bus** shall be tested. Testing shall continue into the 50-200 kV system until a non-**bulk power system** result is obtained, as detailed in Section 3.5. Once a non-**bulk power system** result is obtained, it is permitted to forgo testing of connected *buses* unless one of the following considerations shows a need to test these *buses*:
  - Slower remote clearing times.
  - Higher short-circuit levels.
3. Generator *buses* operated at voltages below 50 kV that are directly connected to a **bulk power system bus** through a transformer connection shall be tested.

Other *buses* not contiguous to the **bulk power system** may also be tested.

### 3.5 Bus-Based Test Methodology

**Transient stability** and steady-state tests are used to determine the **bulk power system** status of the *bus* under test.

Testing is based on application of a three-phase *bus fault* at a single voltage level that is *uncleared locally*. The **protection systems**, including **SPSs**, at the *bus* under test are assumed to be inoperative.

The **transient stability** test is done first to identify *buses* that may be classified as **bulk power system buses**. For those *buses* which are not classified as **bulk power system** in the **transient stability** test, the steady-state test is used to determine the classification..

A positive **bulk power system** determination is based upon the failure to meet the performance requirements specified in section 3.3 in the **transient stability** or the steady-state test.

#### Step 1 - Transient Stability Test

Simulate a three-phase **fault** at the *bus* under test that is *uncleared locally*. This test consists of two steps:

- Step 1a is performed using generic clearing times associated with remote clearing of **elements** connected to the *bus* under test.
- Step 1b is performed using design clearing times associated with remote clearing of **elements** connected to the *bus* under test.

If an entity has remote clearing time information for the **elements** that will be cleared remotely, then the entity may skip Step 1a and directly perform Step 1b.

- 1a. Simulate a three-phase **fault** for at least 10 seconds at the *bus* under test. Do not open any of the **elements** connected to the *bus* under test for the duration of the **fault**. After 10 seconds, simulate tripping of all terminals of each **element** connected to the *bus* under test. For transformers between the *bus* under test and a non-**bulk power system bus**, also simulate the tripping of all terminals of each **element** connected to the non-**bulk power system bus**.

In cases where there is no **fault** interrupting device at the remote terminal of an **element**, open all terminals of all **elements** between the *bus* under test and the interrupting device(s) that will open to clear the **fault**.

It is recognized that, due to the conservative nature of this test, some **elements** could be classified unnecessarily as part of the **bulk power system**. If the above test results in a positive **bulk power system** determination, the following additional testing should be utilized to obtain a more precise determination. Subsequent testing utilizes design clearing times for the conditions being tested, as stated below.

- 1b. Simulate a three-phase **fault** at the *bus* under test that is *uncleared locally* and trip the remote terminals of all **elements** that will open to clear the **fault**. Remote clearing times shall be based on design **fault clearing** times. This test assumes failure of the **protection systems** at the *bus* under test, including failure of communication facilities from the *bus* under test to the remote terminals.

Transformers and other **elements** connected to the *bus* under test shall only be tripped by operation of independent remote **protection groups** capable of clearing a **fault** on the *bus* under test, specifically:

- Fast clearing provided by Directional Comparison Blocking (DCB) schemes shall not be relied upon in **bulk power system** classification
- For transformers connected to the *bus* under test, differential **protection** schemes shall be assumed to be disabled
- In the absence of other **protection** schemes (non-differential **protection** schemes) that would trip the transformer, the transformer will be assumed to remain in-service for 5 seconds after **fault** initiation.

After 5 seconds, the transformer shall be assumed to fail, and the **fault** shall be migrated to the opposite terminal(s) of the transformer (reference Attachment A – Technical Rationale 4).

- The clearing of the migrated **fault** at the opposite terminal(s) shall depend on the transformer **protection** design at the opposite terminal(s):

- If the opposite terminal's transformer **protection** is designed with independence consistent with Directory 4, the **fault** shall be cleared using design **fault clearing** time.
- If not, the migrated **fault** must be cleared remotely consistent with the procedure used for the initial **fault** at the *bus* under test in Step 1b.

If the **fault** results in a failure to meet the performance requirements in Section 3.3, the *bus* under test is classified as part of the **bulk power system**.

The **protective relay** settings at the remote *buses* may be reviewed to determine whether the *bus* under test would not be classified as part of the **bulk power system** if faster remote **fault** clearing were achieved. If **protective relay** settings may be so modified, an assessment shall be conducted to ensure that the faster clearing time does not compromise the security of the **protection system**. Until the **protective relay** settings are modified, the *bus* must be classified as part of the **bulk power system**.

For *buses* not classified as part of the **bulk power system** in Step 1, continue with the Steady-State Test in Step 2. Note that Step 2 can only be performed after either Step 1a or 1b. If a *bus* is classified as part of the **bulk power system** by the **transient stability** Test (Step 1), the Steady-State Test (Step 2) need not be done for that *bus*.

#### Step 2 – Steady-State Test

Simulate the steady-state conditions based on the expected system conditions at the end of the **transient stability** test. The simulation shall:

- Remove all **elements** that were disconnected by the end of the **transient stability** test, including generators that lose synchronism or are tripped due to voltage, frequency or other **protection**.
- Reflect operation of all automatic devices.

Steady-state system performance is assessed against the performance requirements in Section 3.3 following automatic actions. If the post **contingency** steady-state conditions fail to meet the performance requirements under section 3.3, the *bus* under test is classified as part of the **bulk power system**.

In cases where a power flow solution is not obtained, other techniques shall be used to assess the impact of the event on the power system, such as alternative power flow solution algorithms or a reference to past events that occurred under similar conditions. A non-converged power flow solution does not automatically qualify a *bus* as part of the **bulk power system**.

## 4. Classification of Bulk Power System Elements

This section provides the methodology used to identify **bulk power system elements** for NPCC Directory applicability, on the basis of the identified **bulk power system buses**.

### 4.1 Identification of Elements for Directory 4 Applicability

#### Single-Terminal Bulk Power System Elements

For the application of Directory 4, an **element** with a single terminal, such as a generator, shunt reactor, or capacitor bank, is classified as part of the **bulk power system** if the *bus* at which it is connected is classified as part of the **bulk power system**.

#### Multi-Terminal Bulk Power System Elements Where All Terminals are Bulk Power System Buses

An **element** with multiple terminals, such as a transformer or transmission line, is classified as part of the **bulk power system** if any terminal of the **element** is connected to a *bus* that is classified as part of the **bulk power system**.

For multi-terminal **elements** with **bulk power system buses** at all terminals, Directory 4 will apply to all terminals of the **element**.

#### Multi-Terminal Bulk Power System Elements Where One Or More Terminals are Non-Bulk Power System Buses

If one or more of the non-**bulk power system** terminals of a multiple-terminal **bulk power system element** are not designed to meet Directory 4 requirements, the **protection system** design at the **bulk power system** terminal(s) must ensure that the failure of any **protection system component**, with the exceptions of non-redundant **components** as specified in Directory 4, does not result in a violation of the performance requirements in section 3.3 of this document. To accomplish this objective, either one of two methods shall be followed:

- a) Two independent **protection groups** at the **bulk power system** terminal(s) of the element must provide **high speed fault clearing** at the **bulk power system** terminal independent of the remote terminal(s)<sup>5</sup> for three-phase **faults** on at least 70% of the apparent impedance of the transmission line or 70% of the positive sequence impedance of the transformer<sup>6</sup>, beginning at the **bulk power system** terminal. Additionally, two

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<sup>5</sup> Throughout this document, the idea of “**high speed fault clearing** independent of the remote terminals” is referenced. This refers to any scheme that could clear faults consistent with NPCC’s definition of **high speed fault clearing**, without relying on any communication or lack of communication from remote *buses*. As an example, Zone 1 protection in a step-distance scheme would meet this condition, while a DCB or permissive overreaching transfer trip (POTT) scheme would not.

<sup>6</sup> Applicable to transformers directly connected to a **bulk power system bus**.



independent **protection groups** at the **bulk power system** terminal(s) of the element must provide **fault** clearing at the **bulk power system** terminal, which may act with an intentional time delay, independent of the remote terminal(s), for any **fault** on the entire **element**.

- b) The **transient stability** test must be applied at various locations between the terminals of the **element** to identify those portions of the **element** where a **fault** with no **protection system** action at the **bulk power system** terminal of the **element** would result in violation of the performance requirements in Section 3.3. The portion of the **element** where such a violation occurs is classified as part of the **bulk power system**. Two independent **protection groups** at the **bulk power system** terminal shall provide **high speed fault clearing** for the portion of the **element** that is classified as being a part of the **bulk power system**, unless transient stability analysis shows that slower clearing times are acceptable.

Reference Attachment A –Technical Rationale 5

## 4.2 Identification of Elements for Directory 1 Applicability

For the application of Directory 1, the **elements** connected to a **bulk power system bus** are categorized as follows:

- **Single-terminal element:** An **element** such as a generator, shunt reactor, or capacitor bank that is connected to a **bulk power system bus**
- **Radial multi-terminal element:** An **element** with multiple terminals, such as a transformer or transmission line, that emanates from a single **bulk power system bus** and is not a part of a transmission path that connects back to other **bulk power system buses**. The presence of a contiguous loop operated at voltage levels below 50 kV is not considered a transmission path that connects back to other **bulk power system buses**.
- **Networked multi-terminal element:** An **element** with multiple terminals that emanates from one or more **bulk power system buses** and is part of a transmission path between **bulk power system buses**.

All single-terminal and all radial multi-terminal **elements** that are connected to **bulk power system buses** are automatically excluded from Directory 1 applicability, provided that the element has two independent **protection groups** with **high speed fault clearing** for close-in **faults** at the **bulk power system bus** (reference Attachment A –Technical Rationale 6).

All networked multi-terminal **elements** that are connected to **bulk power system buses** are considered **bulk power system elements** for Directory 1 applicability, unless the **element** is excluded following the study-based exclusion process detailed below (reference Attachment A –

Technical Rationale 6). There is no requirement to use the study-based exclusion process unless an entity seeks to exclude multi-terminal non-radial **elements** from Directory 1 applicability.

To be eligible for exclusion via the study-based exclusion process, the first step is to identify candidate **element(s)** for exclusion. A candidate **element** is a networked multi-terminal **element** that has no more than one terminal connected to a *bus* operated at 345 kV or higher. For example, a 345 kV transmission line that is a networked multi-terminal **element** may not be excluded using the study-based exclusion process.

An evaluation shall be performed to ensure that critical events related to the candidate **element** do not result in the violation of performance requirements in Section 3.3 of this document. The critical events related to the candidate **element** include events that would impact the candidate **element** or events that involve the loss of the candidate **element**.

Testing shall evaluate the loss of a critical facility with no system adjustments followed by a Category 1 event as defined in Directory 1 Table 1. The selection of the critical facilities and Category 1 events for this test are based on critical events related to the candidate **element**.

- A critical facility would include a transmission circuit, transformer, series or shunt compensating device, generator or single pole of a direct current facility.
- System conditions that are typically used for Directory 1 Table 1 **contingency** testing as a part of **Area** Transmission Reviews shall be utilized for this evaluation.
- In consultation<sup>7</sup> with system operations, additional testing of events as defined in Directory 1 Table 3 shall be utilized for specific credible outage conditions that result in a violation of performance requirements in Section 3.3.
- The action of the following SPSs are simulated:
  - **SPSs** that would be armed under the all-**elements**-in-service scenario for the system conditions studied.
  - **SPSs** that would be automatically armed with the critical facility out of service.

For example:

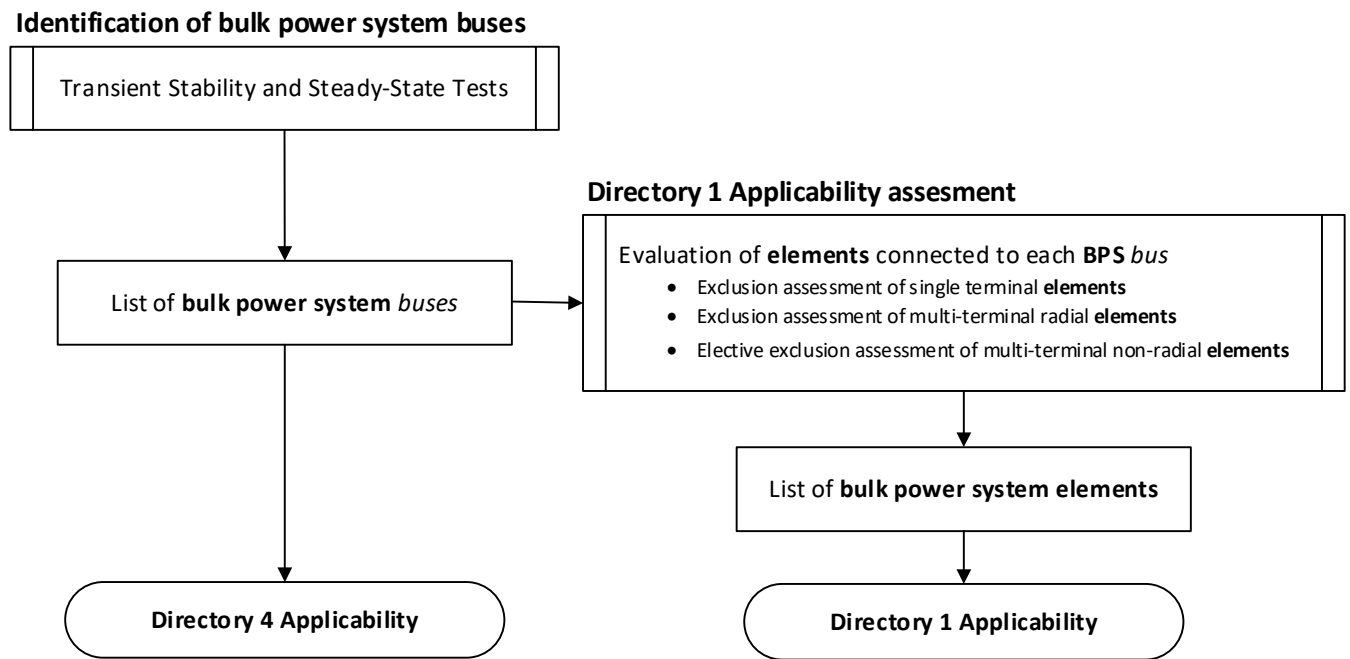
- The loss of a line followed by the immediate **contingency** loss of a double circuit tower that would potentially overload a candidate **element** would be tested under this evaluation.
- The loss of the candidate **element** followed by the immediate **contingency** loss of a double circuit tower that would potentially overload other **bulk power system elements** would be tested under this evaluation.

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<sup>7</sup> At the time the exclusion process is performed.

Where all **elements** connected to a **bulk power system bus** have been excluded from Directory 1 applicability, the *bus* is also excluded from Directory 1 applicability.

Figure 3 outlines the overall methodology to determine Directory 1 and Directory 4 applicability for *buses* and **elements**.



**Figure 3 – Identification of bulk power system elements for Directory 1 and Directory 4 Applicability**

## 5. Application and List Maintenance

In the event of modification to the power system, each **Area** shall perform a partial assessment of the **bulk power system** status of *buses* near the location of the system modification. Testing shall adhere to the testing strategy provided in section 3.4 and shall include, at a minimum, any new *buses* that are a part of the system modification. Additionally, if there are significant system changes in the vicinity of any **elements** excluded from Directory 1 applicability, then the exclusion shall be re-evaluated.

To ensure that the cumulative impacts of system changes are not overlooked, each **Area** shall be responsible for a comprehensive reassessment of **bulk power system** status of *buses*, including **elements** excluded from Directory 1 applicability, at least once every five years. The reassessment may not require **Area**-wide testing if changes in system conditions and assumptions since the last comprehensive **bulk power system** assessment are minimal.

Each **Area** shall be responsible for the application of the *Classification of Bulk Power System Elements* as described in this document and shall submit proposed changes to its **bulk power system** classification to the TFSS. Before proceeding to review at TFSS, all entities who own or operate the facilities whose **bulk power system** status or Directory 1 applicability has changed shall be consulted with regards to study assumptions and results as listed below.

Supporting documentation for this review shall include, but not be limited to:

- The rationale for system conditions specified in section 3.1.
- The rationale for testing assumptions not specified in section 3.2.
- The criteria used to evaluate the performance requirements in section 3.3 such as **transient stability** criteria, voltage criteria, thermal criteria, loss of source and/or loss of **load** thresholds.
- The reliance on any **SPS** action as a part of the testing.
- Supporting evidence for exclusions to Directory 1 applicability.
- Supporting evidence for the **bulk power system** classification of a portion of an **element** for Directory 4 applicability under Section 4.1 condition (a).
- Any concerns related to NPCC-wide, inter-**Area** reliability raised during the consultation described above.
- Detailed results of the testing shall be provided to the TFSS upon request.

The “NPCC **Bulk Power System** List” will be maintained by the TFSS. Additions to and removals from the NPCC **Bulk Power System** List will be submitted by TFSS to the Reliability Coordinating Committee (RCC) for approval. The NPCC **Bulk Power System** List shall also include:

- Any **elements** identified for exclusion from Directory 1 applicability.
- Any **elements** where only a portion of the **element** is classified as **bulk power system** for Directory 4 applicability.

## 5.1 Modifications to the Bulk Power System List

When, upon application of this methodology, an **Area** identifies a change to the **bulk power system** classification of a *bus*, the **Area** shall present documentation of the analysis supporting the change to the TFSS. Once the change in classification of the *bus* is recommended by the TFSS and approved by the RCC, the *bus* will be added to or removed from the NPCC **Bulk Power System** List with the appropriate comments and information.

If the application of the methodology identifies changes to **elements** excluded from Directory 1 applicability or changes to **elements** where only a portion of the **element** is classified as **bulk power system** for Directory 4 applicability, as per section 4.1, the **Area** shall present documentation of the analysis to the TFSS. Once the change in classification of the **element** is recommended by the TFSS and approved by the RCC, the **element** will be added to or removed from the NPCC **Bulk Power System** List with the appropriate comments and information.

All NPCC Task Forces and the Compliance Committee will be notified once the **Bulk Power System** List is updated.

Within three months of an **element** being identified as a **bulk power system element**, a plan and schedule for achieving compliance with Directory 4 shall be provided to the Task Force on System Protection (TFSP) for review and acceptance. TFSP may require modifications to the proposed plan and schedule.

Within three months of an **element** being identified as a **bulk power system element** to which Directory 1 applies, a plan for incorporating the **element** into Directory 1 analysis shall be provided to the NPCC Task Force on Coordination of Planning (TFCP) and to the NPCC Task Force on Coordination of Operation (TFCO) for review and acceptance. TFCP or TFCO may require modifications to the proposed plan and schedule.

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Reviewed for concurrence by: TFSS, TFCO, TFSP, and the Task Force on Infrastructure Security & Technology (TFIST)

Review frequency: 4 years

References:

*NPCC Glossary of Terms*

*NPCC Directory 1 Design and Operation of the Bulk Power System*

*NPCC Directory 4 System Protection Criteria*



## Attachment A: Technical Rationales

### Technical Rationale 1 – Performance Requirements

Previous versions of this document relied on a demonstration of test results that show **significant adverse impact** outside of the **local area**. In order to improve consistency and reduce ambiguity in the **bulk power system** classification procedure, a defined set of performance requirements against which test results can be compared has been developed. The objective of the revised performance requirements is to add clarity and improve consistency in the identification of system performance that would constitute an NPCC-wide system reliability concern.

The occurrence of any of the impacts below should be deemed to be an NPCC-wide system reliability concern and require classification of the tested *bus* or **element** as part of the **bulk power system**.

- System instability that cannot be demonstrably contained within the **Area** or a defined portion of the system that crosses **Areas**.
- Cascading that cannot be demonstrably contained within the **Area** or a defined portion of the system that crosses **Areas**.
- Net loss of source or loss of **load** greater than an **Area's** threshold, if applicable.

The means by which each entity actually evaluates and measures the impacts is documented through technical guidelines and methods. For example, transient voltage or damping criteria may be a means to measure potential system instability and containment of a certain level of cascading may be analyzed through successive tripping of **elements** overloaded above applicable emergency ratings.

System instability, for the purposes of these performance requirements, is the inability of the system to return to a state of equilibrium following a disturbance. System instability would include an oscillatory response where the oscillations are not demonstrated to be clearly positively damped within 30 seconds of the initiating event. Instances of instability that can be demonstrably contained, such as a voltage collapse affecting a small or radial subsystem, or generator instability for which technical analysis can reasonably show the instability does not propagate through the system (e.g. by showing that **protection** equipment will cleanly separate a small or radial subsystem, and that the rest of the power system will remain stable), are not considered system instability.

Containment of cascading can be determined by examining sequential tripping caused by exceeding stability limits, voltage limits and/or transmission **element** loading. When cascading crosses to a neighboring **Area**, the affected **Area** shall be consulted to determine the severity of



the impact on the performance of the system in the neighboring **Area**. Cascading analysis can lead to three outcomes following the sequential tripping of **elements**:

- 1) Cascading can be demonstrably contained to a relatively small portion of the system<sup>8</sup>.
- 2) Cascading can be demonstrably contained while causing the loss or unintentional separation of a portion of the system that results in the net loss of **load** or source greater than the **Area's** threshold.
- 3) Cascading may not be demonstrably contained.

Outcome 1 is not considered a violation of the performance requirement, because the loss of a relatively small portion of the system would not impact other NPCC **Areas**. However, outcomes 2 and 3 are violations of the performance requirement.

Finally, due to the characteristics of some **Areas**, a net loss of source or **load** beyond a certain threshold may be deemed as impactful to other **Areas** for various reasons, such as frequency stability, reserve requirements, widespread electric interruption, and overloads on tie lines. An **Area's** loss of source and/or loss of **load** threshold will be determined by each **Area** with due consideration to impacts outside of the **Area**. The threshold values or lack of threshold values shall be presented to and reviewed by the TFSS. An **Area** may have different thresholds for various conditions studied (e.g. summer vs. winter, light vs. peak loading, etc.).

## Technical Rationale 2 – Directional Comparison Blocking Scheme Assumptions

The 2009 revision of this document allows for the use of clearing times faster than those provided by remote delayed clearing when directional comparison blocking (DCB) schemes or other similar **protection** schemes are used. That revision contained the following language:

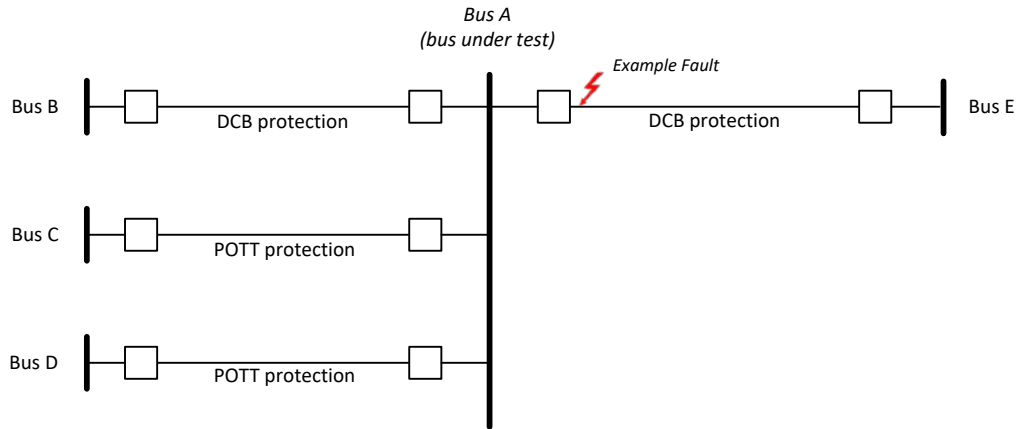
*“Some protection groups (e.g. directional comparison blocking) at remote terminals may provide high-speed **fault clearing** for faults at the bus under test. In order to test the effects of longer **fault clearing** times for **fault** conditions when these remote protection groups would not provide high speed **fault clearing**, for either test (1a) or (1b) above:*

- *High-speed **fault clearing** at remote terminals must be ignored; or*
- *Testing must vary the placement of the 3-phase **fault** on the elements connected to the bus under test to include locations beyond the reach of the high-speed tripping relay element at the remote terminal.”*

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<sup>8</sup>Provided that any cascading that crosses to neighboring **Areas** has been examined by the affected **Areas**, and determined to be an acceptable impact.

While there are *buses* where this provision has been applied, the use of DCB schemes for faster clearing times in **bulk power system** classification may fail to correctly capture that a partial failure of a DCB scheme may be more severe than a complete failure of all **protection systems** at a *bus* under test.



**Figure 4 – Sample System Diagram for Explanation of DCB Assumptions**

With respect to Figure 4, consider the following:

- Partial **protection system** failure can be a more severe test for DCB scheme failure than the complete failure of the local **protection system** at the *bus* under test. For a **fault** at *bus A* (the *bus* under test), a total **protection system** failure would lead to **high speed fault clearing** at *buses B* and *E*, as these *buses* would not receive a blocking signal from *bus A*. However, a partial **protection** failure could leave the communication between *bus A* and *buses B* and *E* intact, but still result in local **protection** being disabled. *Buses B* and *E* would then receive a blocking signal, and **high speed fault clearing** at these *buses* would not occur.
- For a close-in **fault** at *bus A* on the circuit A-E, if a non-redundant relay at *bus A* protecting the circuit A-E fails, the **fault** would be cleared as follows:
  - The DCB scheme at *bus E* protecting circuit A-E would detect the close-in **fault** at *Bus A* and would correctly trip with **high speed fault clearing**.
  - The DCB scheme at *bus A* protecting circuit A-E would not trip as the scheme would be disabled by the failure of a non-redundant relay.
  - The reverse-looking element of the DCB scheme at *bus A* on circuit A-B would correctly detect the **fault** in the reverse direction, and would send a blocking signal to *bus B*. Therefore, **high speed fault clearing** would not occur at *bus B*.

- Protection for circuits A-C and A-D at *bus* A would correctly detect that the **fault** is in the reverse direction, and would not send a permissive signal to *buses* C or D. Therefore, **high speed fault clearing** would not occur at *buses* C or D.

While it is possible to move the test **fault** along each circuit to verify the reach of all DCB schemes installed on circuits connected to the *bus* under test, due to infeed and outfeed, the effective reach of a DCB scheme's forward and reverse elements may vary with changing system conditions. As such, determining an appropriately conservative **bulk power system** classification test by varying system conditions as well as considering the effects of partial **protection system** failures in order to maximizing **fault** current and extend clearing times is very resource intensive. These studies are difficult to perform, and can result in a less conservative outcome.

Therefore, with the elimination of use of fast clearing from DCB or similar schemes, moving **faults** along **elements** is no longer required because delayed clearing is assumed regardless of the **protection** scheme(s) utilized. This change will lead to a reduction in the overall resource requirements to run the methodology, while ensuring that the effects of a partial **protection system** failure are captured more completely than they were in previous versions of the A-10 methodology.

### **Technical Rationale 3 – Elimination of the Adjacent Circuits on a Common Tower Test**

The 2009 revision of this document added a requirement to test single-line-to-ground **faults** on different phases of adjacent circuits on common towers, with a **protection** failure at one of the terminal stations. The intent of this test was to capture situations where the loss of two transmission circuits that do not share a common *bus*, with no local **protection system** action at one *bus*, is more severe than the loss of an entire *bus* with no local **protection system** action. However, in the (approximately) ten years of this requirement's existence, no NPCC **Area** has identified a **bulk power system bus** solely due to this test. As this is an onerous test to run with no proven reliability benefit, it has been eliminated from this revision of the document.

## Technical Rationale 4 – Transformer Fault Propagation

NPCC Areas have used different assumptions regarding the treatment of transformers at the *bus* under test. In most cases, these transformers will be protected by differential **protection**. As a result, they will not be tripped due to a **fault** on the *bus* under test, since that **fault** will be outside of the differential scheme's zone of **protection**. While other auxiliary **protection** schemes may eventually trip the transformer, modeling these schemes would not significantly change study results.

In order to improve consistency in application of the **bulk power system** classification test, this revision standardizes the assumptions around the treatment of these transformers. The standardized assumption was based on the premise that a transformer exposed to three-phase **fault** current at the terminals would eventually fail, with the **fault** propagating to the **non-faulted** terminal of the transformer after five seconds. The five-second delay is based on the transformer design standard IEEE Standard C57.109-1993 which requires the transformers to withstand the three-phase short circuit current at their terminal for at least two seconds, and therefore five seconds is deemed appropriate. Depending on the generation dispatch and system configuration, the three-phase short circuit current might be lower than the short circuit current that can fail the transformers in two seconds.

The subsequent actions at the **non-faulted** terminal *bus* are dependent on the **protection system** design at that terminal. The following actions shall be taken:

- 1) If the **non-faulted** terminal *bus* of the transformer(s) is a part of the **bulk power system** or the **protection** at this *bus* cannot be completely disabled by **protection** failures at the **faulted** terminal *bus*: Assume that some **protection** on the **non-faulted** *bus* will act to clear the transformer(s) after five seconds, or faster if actual **protection** information is available. This assumption is conservative because the **non-faulted** side has independent **protection groups**, so at least one **protection system** would still be able to act. In most cases, this will take the form of a *bus fault* on that *bus*, cleared in the time normally assumed for *bus faults* with no **protection** failures. This assumption would apply to both **transient stability** and steady-state tests.
- 2) If the **protection** at the **non-faulted** terminal *bus* of the transformer(s) can be completely disabled by **protection** failures at the **faulted** terminal *bus*: Assume that the **fault** migrates to the **non-faulted** side of the transformer(s) after five seconds, and that **elements** connected to the **non-faulted** side also clear remotely. This would take a similar form to a **bulk power system** classification test on the previously **non-faulted** terminal of the transformer. This reflects the fact that a single **component** failure could disable all **protection** at both the *bus* under test and the **non-faulted** transformer terminal. A

possible mitigation for this situation could be to eliminate the possibility of a **protection system** failure at the **faulted bus** disabling the non-**faulted bus's protection**. This assumption would apply in both **transient stability** and steady-state tests.

This approach will improve consistency in the application of the A-10 test. In most cases, any **transient stability** impacts of the initial **fault** will have occurred within the first five seconds, and the system will either be completely unstable or approaching a steady-state by the time the **fault** migrates to the opposite terminal of the transformer.

## Technical Rationale 5 – Directory 4 Applicability

For multi-terminal **elements** such as transmission lines and transformers connecting **bulk power system** and non-**bulk power system buses**, Directory 4 does not explicitly require full independence or physical separation of all **protection systems** at the non-**bulk power system bus**. NPCC **Areas** have used differing approaches, such as backup **protection**, to ensure that **faults** on **bulk power system-to-non-bulk power system elements** could still be cleared reliably in the event that the non-**bulk power system** terminal experiences a **protection system** failure. Previous revisions of this document have provided the opportunity for **Areas** to test **faults** at various points along a transmission line in order to determine the portion of the line that should be considered part of the **bulk power system**, but this provision has rarely been used. The Directory 4 applicability language in section 4.1 is meant to improve consistency in the application of Directory 4, and to reduce the engineering analysis associated with testing **faults** at various points on a transmission line.

The Directory 4 applicability section of this document recognizes that, in most cases, two independent **protection groups**, at the **bulk power system** terminal of a transmission line, will provide **high speed fault clearing**, independent of the remote terminal(s), for most of the line. Due to the impedance of the line in question and the networked topology of the power system, the relative strength of a **fault** as seen from the **bulk power system bus** decreases as the **fault** is moved away from the **bulk power system** terminal of a line. In the experience of NPCC members, the **bulk power system** boundary on a transmission line has never tested outside of the reach of the **high speed fault clearing** (independent of the remote terminal(s)) of the independent **protection groups** at the **bulk power system bus**. In recognition of this fact, a reach that covers at least 70% of an element's impedance (beginning at the **bulk power system** terminal) is considered sufficient instead of further testing to determine the **bulk power system** boundary's exact location on a **bulk power system-to-non-bulk power system** element. (The 70% number was chosen based on the typical zone 1 reach used by NPCC members.)

In addition to **high speed fault clearing** on at least 70% of the element's impedance, option (a) in section 4.1 also requires two independent **protection groups** to clear **faults** anywhere on the **bulk power system-to-non-bulk power system** element, possibly with an intentional time delay. Without testing to show otherwise, there is no guarantee that **faults** near the non-**bulk power system** terminal of an **element** would be cleared by other *buses* remote to the **bulk power system** terminal of the **element**. The *bus*-based classification test at the non-**bulk power system** terminal of the line has shown that **faults** cleared with backup **protection** times will not cause a violation of this document's performance requirements, but it is still possible that completely uncleared **faults** would show a violation of this document's performance requirements. The requirement for two independent **protection groups** at the **bulk power system** terminal ensures that these **faults** will be cleared, and will not remain uncleared indefinitely.

In the event (for example, on three-terminal lines) that two independent **protection groups** do not provide **high speed fault clearing**, independent of the remote terminal(s), for at least 70% of the element's impedance, option (b) in section 4.1 requires that additional analysis must be performed to determine if the **protection system** design is adequate. To ensure that a **fault** on the **bulk power system** portion of the element would be cleared by two independent **protection groups** at the **bulk power system** terminal(s), testing must be performed to show that the **bulk power system/non-bulk power system** boundary is located inside the reach of the **bulk power system** terminal's independent **high speed fault clearing**, independent of the remote terminal(s).

## Technical Rationale 6 – Directory 1 Applicability and Exclusions

### Automatic Exclusion of Single-Terminal Elements

A single-terminal **element** is an **element** such as a generator, shunt reactor, or capacitor bank that is connected to a **bulk power system bus**.

Based on Section 4.2 of this document, if an element is excluded from Directory 1, two independent **protection groups** will provide **high speed fault clearing** at the **bulk power system bus** for close-in **faults** on single-terminal **elements**.

Given that close-in **faults** on single-terminal **elements** will be cleared with two independent **protection groups** with **high speed fault clearing**, single-terminal **elements** may be automatically excluded from Directory 1 applicability, based on the following:

- Contingencies are not expected to have an impact on single-terminal **elements**; therefore, there is no requirement to monitor single-terminal **bulk power system elements** for Directory 1 applicability.
- The impacts of contingencies involving single-terminal **bulk power system elements** on the remaining **bulk power system** are not expected to be worse than the impacts of breaker failure contingencies at the **bulk power system bus**.
- Breaker failure contingencies at the **bulk power system bus** to which the excluded **element** is connected will continue to be evaluated as a part of Directory 1 analyses, provided that they also involve a non-excluded **bulk power system element**.

### **Automatic Exclusion of Radial Multi-Terminal Elements**

A radial multi-terminal **element** is an **element** with multiple terminals, such as a transformer or transmission line, that emanates from a single **bulk power system bus** and is not a part of a transmission path that connects back to other **bulk power system buses**. The presence of a contiguous loop operated at voltage levels below 50 kV is not considered a transmission path that connects back to other **bulk power system buses**. A point where the system is “normally open” is not considered a transmission path, and the **elements** on either side of the normally open point can be considered radial **elements**.

Based on Section 4.2 of this document, all excluded **elements** will have two independent **protection groups** that provide **high speed fault clearing** at the **bulk power system** terminal for portions of the multi-terminal line that require independent **protection groups** to avoid the violation of the performance requirements in section 3.3.

Given that the **protection systems** at the **bulk power system** terminal are consistent with Directory 4 requirements, radial multi-terminal **elements** are automatically excluded from Directory 1 applicability, based on the following:

- The radial multi-terminal **element** was not intended nor designed to participate in transfer of bulk **power** and contingencies are not expected to have an impact on radial **elements**; therefore there is no requirement to monitor radial **bulk power system elements** for Directory 1 applicability.
- The remote terminal of the radial multi-terminal **element** is non-**bulk power system** as demonstrated via testing in section 3.5 where the loss of the radial portion of the system meets the performance requirements in section 3.3.
- The impacts of contingencies involving radial multi-terminal **bulk power system elements** on the remaining **bulk power system** are not expected to be worse than the impacts of breaker failure contingencies or common-tower contingencies at the **bulk power system bus**.

- Breaker failure contingencies at the **bulk power system bus** to which the excluded **element** is connected will continue to be evaluated as a part of Directory 1 analyses, provided that they also involve a non-excluded **bulk power system element**.

### Study-based Exclusion of Networked Multi-Terminal Elements

A networked multi-terminal **element** is an **element** with multiple terminals that emanates from one or more **bulk power system buses** and is considered to be a transmission path between **bulk power system buses**.

All networked multi-terminal **elements** that are connected to **bulk power system buses** are considered **bulk power system elements** for Directory 1 applicability, unless they are excluded based on the study-based exclusion process. The study-based exclusion process is used to consistently apply the existing language provided in Directory 1 revision 2, Tables 1 & 3 performance requirement (ii):

*“Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining **bulk power system**.”*

To be eligible for exclusion via the study based exclusion process, the first step is to identify candidate **element(s)** for exclusion.

**Elements** with multiple terminals operated at 345 kV or higher are not considered a candidate **element** because these **elements** typically participate in bulk **power** transfers. Note that this does not prevent them from being considered part of a small or radial portion of the system in Directory 1 assessment. For clarification, the decision to not utilize the study-based exclusion process at the time of **bulk power system** classification does not preclude use of the “loss of small or radial portion of the system” concept at any future Directory 1 assessment.

The study-based exclusion process evaluates events that are expected to capture the impacts of Directory 1 Table 1 and Table 3 events. The impacts for these evaluated events are measured against the performance requirements used for the *bus*-based classification test. These performance requirements are considered sufficient for the evaluation of Directory 1 Table 1 and Table 3 events because these performance requirements are used to identify NPCC-wide system reliability concerns. Furthermore, meeting these performance requirements is sufficient to not classify a *bus*, and all **elements** connected to that *bus*, as being a part of the **bulk power system**.

### Capturing Impacts of Table 1 Events:

**System Conditions Evaluated:** System conditions that are typically used for Directory 1 Table 1 **contingency** testing as a part of **Area** Transmission Reviews shall be utilized for this evaluation.



To capture the impacts of Directory 1 events, the system conditions must represent those utilized for Directory 1 **Area** Transmission Reviews. The action of the following **SPSs** shall be simulated:

- **SPSs** that would be armed under the all-**elements**-in-service for the system conditions studied
- **SPSs** that would be automatically armed with the critical facility out of service

**Events Evaluated:** The following events are used to represent the impacts of critical Directory 1 events.

- Loss of a critical facility,
- Followed by no system adjustments,
- Followed by any critical Category 1 event described in Directory 1 Table 1.

The critical facilities and critical Category 1 events described above are based on events that would impact the candidate **element** or events that involve the loss of the candidate **element**.

Testing with the loss of a critical facility followed by no system adjustments is used because:

- The evaluation of Directory 1 Table 1 Category 1 events with a critical facility out of service is considered to be more severe than the evaluation of the Directory 1 Table 1 Category 1 events with all system **elements** in-service.
- System adjustments are not allowed after the critical facility is taken out of service because operators would not have awareness of system adjustments needed to prepare for the next **contingency** and/or resolve violations on the excluded **elements**. This is because provision for system adjustments might not be made in the operating or operations planning time frames to mitigate the effects of **contingency** combinations involving **elements** excluded from Directory 1 applicability. This is a more stringent test than required by Directory 1, where system adjustments are allowed. As such, if there is a violation of a Directory 1 performance requirement then performing the study-based exclusion test will also identify the NPCC-reliability concern and therefore additional exclusion testing is not warranted.
- The arming of an **SPS** via operator action after the loss of a critical element is considered a system adjustment

#### Capturing Impacts of Table 3 Events:

This test is only performed if an **Area**, in consultation with system operations at the time the exclusion process is performed, is aware of system conditions where Table 3 events could result in a violation of performance requirements in Section 3.3.

**System Conditions Evaluated:** The system conditions evaluated must represent the specific credible outage conditions that were identified in consultation with system operations where Directory 1 Table 3 events could result in a failure of the performance requirements in section 3.3.

**Events Evaluated:** Only critical events as defined in Directory 1 Table 3 that are expected to cause a violation of the performance requirements in section 3.3 are evaluated.