

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Request for Data or Information – DRAFT 2

Order No. 754 Single Point of Failure  
on Protection Systems

**RELIABILITY | ACCOUNTABILITY**



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## Introduction and Survey Scope

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In accordance with Section 1600 of the NERC Rules of Procedure,<sup>1</sup> NERC may request data or information that is necessary to meet its obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Federal Energy Regulatory Commission's ("FERC") regulations ("data request"). This is a proposal for such a request.

On September 15, 2011, FERC issued [Order No. 754](#)<sup>2</sup> *Interpretation of Transmission Planning Reliability Standard* in which FERC stated that "there is an issue concerning the study of the non-operation of non-redundant primary protection systems e.g., the study of a single point of failure on protection systems."<sup>3</sup> FERC also directed NERC to initiate a process "to explore this reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter."<sup>4</sup>

On October 24 and 25, 2011, a Technical Conference on "Single Point of Failure on Protection Systems" was held by FERC that was attended by FERC staff, NERC staff, and several industry subject matter experts from the United States and Canada. At the Technical Conference, three single point of failure<sup>5</sup> events were discussed including an extended discussion of the so-called "Westwing Outage" that occurred in 2004 on the Western Interconnection. NERC staff believes that the prudent approach to address this issue is to first discover the extent and risk involved with single point of failure events. Therefore, NERC staff seeks approval of this Section 1600 data request as the proper approach to determine the risks to the bulk power system ("BPS") posed by potential single point of failure events, so that NERC can then develop an appropriate response to address the issue. Accordingly, NERC is issuing this data request in accordance with the requirements of Section 1602.1 of the NERC Rules of Procedure. NERC initially provided this proposed data request to FERC for information on December 14, 2011. NERC previously posted this proposed data request for public comment for a forty-five (45) day comment period. Based on consideration of comments received during the posting NERC has decided to post this proposed data request a second time and provided the revised proposed data request to FERC on April 17, 2012. NERC is hereby posting this revised proposed data request for public comment for a second forty-five (45) day comment period. After consideration of comments received, NERC will present this proposed data request to the NERC Board of Trustees for approval, as required by Section 1602 of the NERC Rules of Procedure. Upon NERC Board of Trustees approval, this data request will be issued and become mandatory.

The purpose of this survey is to solicit data and information from each Transmission Planner in the United States and Canada, in coordination with Generator Owners, Transmission Owners, and Distribution Providers in its transmission planning area, to identify specific information regarding potential single points of failure on their protection systems in order to determine

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<sup>1</sup> NERC's Rules of Procedure are available at: [http://www.nerc.com/files/NERC\\_Rules\\_of\\_Procedure\\_EFFECTIVE\\_20111117.pdf](http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20111117.pdf).

<sup>2</sup> *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 ([http://www.nerc.com/filez/standards/order\\_754.html](http://www.nerc.com/filez/standards/order_754.html))

<sup>3</sup> *Ibid*, at P 19 (2011). ("Order No. 754")

<sup>4</sup> *Ibid*, at P 20 (2011). ("Order No. 754")

<sup>5</sup> In general terms, a single point of failure exists when failure of a single component can affect the operation of all protection systems applied on an Element(s). For the purposes of this Request for Data or Information, single point of failure would be reported whenever a protection system component does not meet one of the attributes defined in Table B.

whether there is a risk to BPS reliability. Responding to the data request is mandatory for registered entities in the United States. It is not mandatory for registered entities in Canada to respond, but Canadian entities are strongly encouraged to submit data so that decisions regarding the concern stated in Order No. 754 can be based on complete data across North America.

## NERC Contact Information

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The survey must be completed in electronic format. Should the submitting entity experience any issues with submitting its data or identifies a discrepancy between the data request and the instructions in the reporting template, contact the project manager below. While NERC does not anticipate that any Confidential Information will be required to complete the responses to this data request, if any entity believes that its responses to this survey are confidential requiring safeguards, submit such data in accordance with NERC Rules of Procedure section 1502.1 or contact the project manager directly for instructions.

Official correspondence may be mailed to:

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## Authority

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Under Section 215 of the Federal Power Act (16 U.S.C. § 824o), Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation’s bulk power system, and with the duties of certifying an Electric Reliability Organization (“ERO”) that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. NERC was certified as the ERO on July 20, 2006. NERC’s authority for issuing this survey is derived from Section 215 of the Federal Power Act, and from the following sources:

**NERC is requesting this information in accordance with its authority provided in 18 C.F.R. §39.2(d), which provides:**

Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

**NERC Rules of Procedure Section 1600 provides:**

***1601. Scope of a NERC or Regional Entity Request for Data or Information***

*Within the United States, NERC and regional entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission’s regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and regional entities may request comparable data or information, using such authority as may exist pursuant to these rules and as may be granted by ERO governmental authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to requirements contained in any Reliability Standard to provide data or information; the requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.*

***1602. Procedure for Authorizing a NERC Request for Data or Information***

- 1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission’s Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or*



- modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with paragraph 1602.2 or issuing the request or modification to reporting entities following approval by the Board of Trustees.*
2. *NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.*
    - 2.1. *A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information (“reporting entities”); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., “confidential,” “critical energy infrastructure information,” “aggregating” or “identity masking”); and (vi) an estimate of the relative burden imposed on the reporting entities to accommodate the data or information request.*
    - 2.2. *A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the reporting entities to accommodate the modified data or information request, and (iii) any other items from paragraph 1.1 that require updating as a result of the modifications.*
  3. *After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC’s evaluation of the comments and recommendations, to the Board of Trustees.*
  4. *In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.*
  5. *NERC may make minor changes to an authorized request for data or information without board approval. However, if a reporting entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require board approval before they are implemented.*
  6. *Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the ERO governmental authority.*

**1603. Owners, Operators, and Users to Comply**

*Owners, operators, and users of the bulk power system registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a reporting entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the reporting entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.*

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## Survey

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### Description

The survey seeks to identify Elements<sup>6</sup> within each transmission planning area on which a three-phase fault accompanied by a protection system failure could result in a potential reliability risk. The following items will be reported in accordance with the data reporting template:<sup>7</sup>

- Statistics concerning the buses evaluated
- Statistics concerning the attributes of the protection system(s) associated with each identified Element
- Statistics concerning the attributes of the station DC supply at selected buses in each transmission planning area

### Method

The Transmission Planner and the Generator Owners, Transmission Owners, and Distribution Providers within the Transmission Planner's planning area may follow the specific steps below as their method for creating the statistics associated with this data request. Entities may use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, and may use information from existing studies (e.g., Category D simulations from transmission planning assessments) and existing assessments of protection systems in developing responses to the data request.

The method will produce two lists of buses. The first list ("List of Buses to be Tested" developed in step 1) will be the complete set of buses which meet the Criteria in Table A, "Criteria for Buses to be Tested." The second list (final "List of Buses to be Evaluated" developed in step 9) will be a subset of the first, and will contain all of the buses from the first set, which have both of the following characteristics.

- The bus has at least one Element<sup>8</sup> for which the protection system does not fully meet the redundancy attributes for all component categories of Table B, "Protection System Attributes to be Evaluated."
- Planning studies simulating a three phase fault, show that clearing times resulting from a single point failure of at least one protection system on an Element connected to that bus will result in system performance exhibiting one of the adverse impacts identified in Table C, "Performance Measures."

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<sup>6</sup> Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

<sup>7</sup> The data request reporting template is provided with the data request as a tool to assist the Transmission Planner and will not be used to submit actual data. NERC will issue further guidance on the method of reporting.

<sup>8</sup> All capitalized terms in this document are defined terms from the *Glossary of Terms used in Reliability Standards*. The *Glossary of Terms used in Reliability Standards* is available at [http://www.nerc.com/files/Glossary\\_of\\_Terms.pdf](http://www.nerc.com/files/Glossary_of_Terms.pdf).

The Protection Systems for all circuits on the second list will be analyzed per step 10 of the method.

Entities that follow an alternate method or utilize existing studies and existing assessments of protection systems in developing responses must assure that the data provided is consistent with the data (in form and substance) that would be developed by using the following method (i.e., the alternate method must yield all of the data requested on the reporting template).

### **Method**

1. Each Transmission Planner will develop a “List of Buses to be Tested,” including each bus<sup>9</sup> in its transmission planning area that meets the criteria in Table A, “Criteria for Buses to be Tested.”
2. Each Transmission Planner will coordinate with Generator Owners, Transmission Owners, and Distribution Providers in its transmission planning area to identify the following:
  - Transformers with through-fault protection<sup>10</sup> that have at least one winding connected at a bus to be tested.
  - Any bus from the list developed in step 1, that can be excluded from testing on the basis that the protection system(s) for all Elements connected to the bus and for the physical bus(es),<sup>11</sup> if any, meet the attributes for all categories of components in Table B, “Protection System Attributes to be Evaluated,” based on the Generator Owner’s, Transmission Owner’s or Distribution Provider’s knowledge of the protection system(s). Each Transmission Planner will create an initial “List of Buses to be Evaluated” by removing from the “List of Buses to be Tested,” any buses identified in this step (step 2).
3. Each Transmission Planner will simulate a three-phase fault on each bus<sup>12</sup> in its transmission planning area on the “List of Buses to be Evaluated” as developed in step 2. The three-phase fault is simulated based on the following parameters:
  - Simulations will be based on case(s) used to perform the most recent annual transmission assessment representing stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment.
  - Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider.

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<sup>9</sup> For the purposes of this testing, all bus configurations will be treated as a straight bus (single-breaker) configuration. For example, a fault simulated on a ring bus configuration is modeled as though the fault is on a straight bus, and not on the terminals of any of the elements connected in the ring bus configuration. A fault simulated on a breaker-and-a-half configuration is modeled as though the two buses are a single straight bus.

<sup>10</sup> Through-fault protection is applied to protect a transformer from the effects of through-fault current for a fault external to the transformer. In the context of this data request, a transformer differential protection zone that overlaps the bus on which the fault is simulated is considered to not provide through-fault protection. Through-fault protection must also be capable of detecting faults on adjacent elements outside the transformer differential zone.

<sup>11</sup> To be excluded from testing, the protection systems must be evaluated for all Elements connected to the “bus” as defined in step 1, as well as the protection systems for the physical bus(es), if any (e.g., the physical buses in a breaker-and-a-half configuration).

<sup>12</sup> The simulated bus fault is representative of the system performance for a bus fault as well as a fault adjacent to the bus on any Element connected to the bus that is outside the bus protection zone.

- For each transformer connected to the faulted bus that is protected by through-fault protection, the Transmission Planner will trip the transformer based on the maximum expected clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider.
  - For each transformer connected to the faulted bus that is not protected by through-fault protection, the Transmission Planner will not trip the transformer or any Element connected to the other terminal(s) of the transformer not connected to the faulted bus.
  - Simulation durations will be long enough to confirm whether system performance exhibits one or more of the adverse impacts identified in Table C, “Performance Measures.”
  - Evaluate the system response for each simulated fault against the criteria in Table C, “Performance Measures.”
4. Each Transmission Planner will revise its initial “List of Buses to be Evaluated” developed in step 2, by removing any buses at which the simulated performance in step 3 does not exhibit any of the adverse impacts identified in Table C, “Performance Measures,” and inform each Generator Owner, Transmission Owner, and Distribution Provider of each of its buses remaining on this intermediate “List of Buses to be Evaluated.”
  5. The Generator Owner, Transmission Owner, and Distribution Provider will review documentation of its protection system(s) at each bus on the “List of Buses to be Evaluated,” developed by the Transmission Planner in step 4. The Generator Owner, Transmission Owner, and Distribution Provider will identify and inform the Transmission Planner of any bus at which the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, “Protection System Attributes to be Evaluated.”
  6. The Transmission Planner will revise the “List of Buses to be Evaluated” by removing the buses identified in step 5 at which the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, “Protection System Attributes to be Evaluated.”
  7. The Transmission Planner will consult with the Generator Owner, Transmission Owner, and Distribution Provider regarding actual clearing times<sup>13</sup> for all Elements that will trip for a fault on each bus identified on the “List of Buses to be Evaluated” as revised in step 6.
  8. The Transmission Planner will simulate a three-phase fault, on each bus identified on the “List of Buses to be Evaluated” as revised in step 6 in accordance with the method described in step 4, except that actual clearing times provided by the Generator Owner, Transmission Owner, and Distribution Provider will be used in place of tripping Elements based on the maximum expected clearing time.

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<sup>13</sup> Simulate clearing based on the remote protection that would operate for the bus fault. Do not simulate operation of any local protection unless the only single point of failure for protection systems on all Elements connected to the bus and the physical bus(es), if any, is a single trip coil and local breaker failure protection is provided, in which case operation of the breaker failure protection may be modeled. In some cases, an Element may not trip at its remote terminal(s) if the protection system at those terminal(s) will not detect the fault. In such cases, the fault will remain uncleared in the simulation. The operation of automatic load shedding schemes or Special Protection Systems may be modeled if the scheme has been installed specifically to respond to the simulated contingency.

9. The Transmission Planner will update the “List of Buses to be Evaluated” that was revised in step 6, by removing from the list each bus at which the simulated system performance in step 8 does not exhibit any of the adverse impacts identified in Table C, “Performance Measures,” and will inform each Generator Owner, Transmission Owner, and Distribution Provider of each of its buses on this final “List of Buses to be Evaluated.”
10. The Generator Owner, Transmission Owner, and Distribution Provider will review documentation of its protection system(s) on each Element connected to each bus on the final “List of Buses to be Evaluated” and the physical bus(es), if any, and provide information to the Transmission Planner necessary for the Transmission Planner to complete the data request reporting template. This data includes:
  - For each bus evaluated in step 9, whether the protection systems meet each of the attributes listed in Table B, “Protection System Attributes to be Evaluated,” for each protection system component category.
  - The attributes of the station DC supply listed in Table D, “Station DC Supply Attributes to be Reported,” for each bus that meets the criteria in Table A, “Criteria for Buses to be Evaluated.”
11. The Transmission Planner will provide the following information in accordance with the data request reporting template.<sup>14</sup>
  - Statistics concerning the buses evaluated
  - Statistics concerning the attributes of the protection system(s) associated with each identified Element
  - Statistics concerning the attributes of the station DC supply at selected buses in each transmission planning area

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<sup>14</sup> Data reporting will be facilitated through a web-based application based on the data request reporting template provided with the data request. The accompanying template is unofficial and intended to assist the Transmission Planner. NERC will issue instructions on the method of reporting consistent with the reporting schedule.

**Table A: Criteria for Buses to be Tested**

Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses directly supplying off-site power to a nuclear generating station
Any additional buses the Transmission Planner believes are necessary for the reliable operation of the bulk power system

**Notes:**

1. For the purpose of applying Table A, circuits include transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers connecting generating resources with gross nameplate rating greater than 20 MVA.
2. For the purpose of applying Table A, a radial line is not counted as a circuit if the only Elements connected to the line are transformers that step down to a voltage below 100 kV.
3. These criteria apply to both BES and non-BES Elements.

**Table B: Protection System Attributes to be Evaluated**

**Protective Relays:** The protection system includes two independent protective relays that are used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.

**Communication Systems:** The protection system includes two independent communication channels and associated communication equipment when such communication between protective relays for communication-aided protection functions (i.e., pilot relaying systems) is needed to satisfy system performance required in NERC Reliability Standards TPL-002-0b and TPL-003-0a.

**AC Current and Voltage Inputs:** The protection system includes two independent AC current sources and related inputs, except that separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing can be used to satisfy this requirement; and includes two independent AC voltage sources and related inputs, except that separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device can be used to satisfy this requirement.

**DC Control Circuitry:** The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply, but does include all the DC circuits used by the protection system to trip a breaker, including any DC distribution panels, fuses, and breakers.

**Notes:**

1. For the purpose of applying Table B, “independent” components indicates that a single point of failure on either component will not prevent protection system operation, except as noted in the table.
2. Physical separation of protection system components is not necessary for protection system components to be reported as independent.
3. The Communication Systems component category is applicable only to transmission line protection. It is not necessary to report data when communication-aided protection functions (i.e., pilot relaying systems) are not needed to satisfy system performance required in NERC Reliability Standards TPL-002-0b and TPL-003-0a, nor is it necessary to report data for transmission transformers, generator step-up transformers, step-down transformers, shunt devices, and buses.



**Table C: Performance Measures**

- |  |
|--|
| 1. Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections |
| 2. Loss of synchronism between two portions of the system  |
| 3. Negatively damped oscillations  |

**Table D: Station DC Supply Attributes to be Reported**

The protection system includes two independent station DC supplies
The protection system includes one station DC supply that is centrally monitored; if the station DC supply is a battery the monitoring includes alarms for both low voltage and a battery open condition
The protection system includes one DC supply that is centrally monitored; the station DC supply is a battery and the monitoring does not include alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is not centrally monitored

**Notes:**

1. A station DC supply includes one station battery and charger, or other single DC source that is used for powering the protection systems and used for tripping. The station DC supply does not include the DC distribution panels; the distribution panels are part of the DC control circuitry.
2. For the purpose of applying Table D, a “centrally monitored” station DC supply is one for which alarms are reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated.

**Rationale****Voltage Thresholds and Facility Selection Criteria**

To balance the need for a broader understanding of the single point of failure concern against the potential burden on entities that would result by including all facilities operated at 100 kV or higher, the sampling method described in Table A, “Criteria for Buses to be Tested” is used to limit the buses to be tested to a representative sample of buses operated at 100 kV or higher. This results in an expedient approach by providing data from a representative sample of buses at all voltage levels on the bulk power system. The sampling criteria are focused on identifying buses for testing at which a single point of failure may have greater potential for adversely

impacting system reliability. The criteria include the relative system strength at the bus (using the number of circuits connected that provide more than a nominal fault current contribution as a surrogate for the system strength) and whether the bus directly supplies off-site power to a nuclear plant. Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes.

Although the system events for which NERC event analysis has identified a protection system single point of failure was causal or contributory have been limited to Elements operated at 200 kV or higher, it is possible that a reliability risk may exist for Elements operated below 200 kV. It would be difficult to extrapolate the assessment results for Elements operated at 200 kV or higher to be representative of those for Elements operated below 200 kV because of differences in protection system design attributes and transmission system characteristics. The impact to bulk power system reliability associated with delayed fault clearing at voltages below 200 kV is expected to be less severe because of higher system impedance and more extensive use of remote backup protection; however, single points of failure on a protection system are more likely to exist on Elements operated below 200 kV. Significant impact to bulk power system performance has occurred for events that originated at voltages below 200 kV and some entities have identified reliability concerns through system studies of single points of failure for certain Elements operated below 200 kV.

#### Protection System Components and Attributes

The protection system components of interest include components whose failure could result in delayed clearing of a fault due to a protection system single point of failure. For the purpose of this data request, protection system components include those components identified in the NERC glossary definition of Protection System<sup>15</sup> as qualified in the System Protection and Control Task Force ([SPCTF technical paper](#))<sup>16</sup> on protection system reliability. The distinctions in the SPCTF technical paper more precisely describe and define the components to be evaluated in the context of single point of failure than the term Protection System.

An alternative approach to limit the scope to the relay types listed in [TPL-001-2](#)<sup>17</sup> for contingency P5 (Table 1, footnote 13) is considered to restrict the components such that the data request would not identify all potential Westwing-type events.<sup>18</sup> Although the data used to support the NERC Industry Alert was based on failures of auxiliary relays and lockout relays, it is not reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs

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<sup>15</sup> NERC Glossary term “Protection System” approved by FERC on 02/03/2012. ([http://www.nerc.com/files/Glossary\\_of\\_Terms.pdf](http://www.nerc.com/files/Glossary_of_Terms.pdf))

<sup>16</sup> Protection System Reliability – Redundancy of System Protection Elements, NERC System Protection and Control Task Force (SPCTF), November 2008. ([http://www.nerc.com/docs/pc/spctf/Redundancy\\_Tech\\_Ref\\_1-14-09.pdf](http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf))

<sup>17</sup> NERC Reliability Standard, TPL-001-2, adopted by the NERC Board of Trustees on August 4, 2011, filed with FERC for approval on October 19, 2011. ([http://www.nerc.com/files/Final\\_-\\_2%20Petition\\_20111019\\_complete.pdf](http://www.nerc.com/files/Final_-_2%20Petition_20111019_complete.pdf)[http://www.nerc.com/files/Final\\_%20-2%20Petition\\_20111019\\_complete.pdf](http://www.nerc.com/files/Final_%20-2%20Petition_20111019_complete.pdf))

<sup>18</sup> The Westwing disturbance resulted in resulting in the loss of approximately 5,000 MW of generation and the potential for collapse of the Western Interconnection. Additional information on this issue can be found in the NERC Industry Alert, [Protection System Single Points of Failure](#). (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern.

#### Performance Measures

The performance measures in the data request are based on the characteristics of events that could adversely impact system reliability similar to the Westwing event. The performance measures identified in the data request include: (1) the loss of synchronism of 2,000 MW or more of generation in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more of generation in the ERCOT or Québec Interconnections, (2) loss of synchronism between two portions of the system, and (3) negatively-damped oscillations.

Tripping generation due to unit instability (loss of synchronism) in excess of the thresholds stated for each interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria will enable the Transmission Planner to identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requesting detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators are adequate to assess the reliability risk associated with single points of failure.

#### Simulation Fault Type

Limiting the data request to a three-phase fault provides a conservative method to identify potential Westwing-type events. Although conservative, this method is appropriate in that single-line-to-ground (SLG) faults with delayed clearing can evolve to a multi-phase fault. Basing studies solely on SLG faults may understate the reliability risk and simulating three-phase faults represents a credible worst-case system condition that may result from a single point of failure, thereby bounding the potential reliability risk to system performance. Simulating a three-phase fault from inception allows Transmission Planners to use existing simulations of a three-phase fault with protection system failure ([TPL-004-0](#), Category D<sup>19</sup>) and eliminates conjecture as to the timing and mechanism by which a SLG fault may evolve to a multi-phase fault.

Additionally, under the NERC Rules of Procedure, NERC is not to collect data or information for requirements of any reliability standard or compliance or enforcement information through a data request. This data request avoids the collection of data that could be used to assess performance with reliability standards because the reliability standards do not establish specific performance criteria for three-phase faults accompanied by protection system failure.

#### Use of Data

The data collected will be used to address the FERC directive to identify whether there is a further system protection issue that needs to be addressed and, if so, what priority it should be accorded relative to other reliability initiatives planned by NERC. If there is a further issue that

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<sup>19</sup> NERC Reliability Standard, TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Effective June 18, 2007 (<http://www.nerc.com/files/TPL-004-0.pdf>)

needs to be addressed, the data collected will be used to qualify the extent of the risk and to identify appropriate and focused measures to address the concern.

This data request has been developed to establish an effective and efficient means to identify whether a reliability concern exists regarding potential single points of failure on protection systems, while limiting the burden on registered entities. Though this approach is expedient for identifying whether a reliability concern exists, an additional data request or additional analysis may be required to quantify the extent of the risk.

### Entities Required to Comply

The entity responsible for coordinating the fulfillment of the data request will be the Transmission Planner. Because planning staff and protection staff may not be in the same company or business unit, this request requires the cooperation of the Generator Owners, Transmission Owners, and Distribution Providers in a Transmission Planner's area. Generator Owners, Transmission Owners, and Distribution Providers must comply with requests for assistance from the Transmission Planners.

Identifying the risk of a Westwing-type event requires information regarding both the susceptibility of the system to adverse performance if a protection system single point of failure occurs and determining where the protection systems contain single points of failure. This requires participation by Transmission Planners, Generator Owners, Transmission Owners, and Distribution Providers. Since the inquiry is related to an approved interpretation of TPL-002-0b the Transmission Planner has been designated as the responsible entity; however, Generator Owners, Transmission Owners, and Distribution Providers are required to support development of the responses to the data request.

### Schedule and Reporting

The completion of this survey and submission to NERC is due within twenty-four (24) months beginning the first day of the first month following NERC Board of Trustees approval and requires periodic reporting as defined in the following table. The reporting portal will be open during the entire period so data can be submitted as soon as it is available, and to allow entities to update previously reported data as necessary through the end of each reporting period.

Scheduled Reporting <sup>20</sup>	
End of 1 <sup>st</sup> month	Transmission Planners must acknowledge the request for data
End of 6 <sup>th</sup> month	Transmission Planners must submit a status report stating percent of work complete
End of 12 <sup>th</sup> month	Transmission Planners must report data for buses operated at 300 kV or higher
End of 18 <sup>th</sup> month	Transmission Planners must report data for buses operated at 200 kV or higher and below 300 kV
End of 24 <sup>th</sup> month	Transmission Planners must report data for buses operated at 100 kV or higher and below 200 kV

### Dissemination of Data

NERC does not believe that the requested information will contain Confidential Information as that term is defined by Section 1501 of the NERC Rules of Procedure. However, if a submitting entity believes that the submitted data is Confidential Information, NERC encourages the entity to mark all confidential or critical energy infrastructure information as instructed in Section 1502.1 of the NERC Rules of Procedure to ensure that all sensitive information will be protected. NERC will handle that data in accordance with Sections 1500 and 1605 of the NERC Rules of Procedure.

### Burden to Entities

The burden of responding to this data request will vary from entity to entity. The most significant factors will be the number of buses within a Transmission Planner's area and the number of connected Elements owned by a Generator Owner, Transmission Owner, or Distribution Provider. A secondary factor will be the extent to which entities are able to use information from existing studies (e.g., Category D simulations from transmission planning assessments) and existing assessments of protection systems in developing responses to the data request. Estimates are provided of the time required to perform analysis and respond to the data request.

The method defined in this data request has been developed to limit the burden on entities while assuring the data collected is sufficient to address the potential reliability risk identified in Order No. 754. Time estimates are based on an assumption that entities follow the method provided in the data request. Entities are not required to follow this method and may use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, provided that the data submitted is consistent (in form and substance) with the data that would be developed by using the method in the data

<sup>20</sup> Periods are referenced from the first day of the first month following NERC Board of Trustees approval of the data request.

request (i.e., the alternate method must yield all of the data requested on the reporting template).

#### Transmission Planners

The burden on Transmission Planners will be similar to the effort to simulate Category D contingencies in accordance with TPL-004-0.<sup>21</sup> In some cases, the Transmission Planner may have simulations from past studies that can be used to support this effort; however, that will depend on a number of factors including the extent to which three-phase faults with protection system failure have been performed and evaluated as part of those Category D contingencies that would produce the more severe system results or impacts.

The request will require coordination and cooperation between planning staff and protection staff. The planning and protection engineers that will need to conduct the studies and submit the data will often be working for different companies or business units. Therefore, time has been included in the estimated burden to accommodate data requests that cross company or business unit lines.

Identification of buses that meet Table A, “Criteria for Buses to be Tested” (Step 1): The estimated time is 8-24 engineer-hours. The time required for this step will vary according to the number of buses in the transmission planning area.

Initial Screening Testing (Step 3): The estimated time is 2 engineer-hours per bus. The time required for this step will vary based on the number of buses tested as some economy of scale is anticipated. The number of buses for which testing is required will depend on the number of buses eliminated in step 2 and the number of buses for which the Transmission Planner may use information from existing studies.

Testing Using Actual Clearing Times (Step 8): The estimated time is 3 engineer-hours per bus. The time required for this step will vary based on the number of buses tested as some economy of scale is anticipated. The number of buses for which testing is required will depend on the number of buses eliminated in step 5 and the number of buses for which the Transmission Planner may use information from existing studies.

Data Submittal (Step 11): The estimated time is 8-24 engineer-hours. The time required for this step will vary according to the number of buses in the transmission planning area.

Applying these estimated times to the example in Appendix 1 that illustrates application of the method, the Transmission Planner in the example with 800 buses on its system would spend approximately 1100 hours on this data request, as outlined below. Note that while this estimate does not explicitly include time for the Transmission Planner to update the “List of Buses to be Evaluated” at various steps in the method, the estimate includes allowances for updating the list as part of associated steps.

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<sup>21</sup> NERC Reliability Standard, TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

	Estimated time	# of buses	Total time
Step 1	24 h	800	24 h
Step 3	2 h/bus	375	750 h
Step 8	3 h/bus	95	285 h
Step 11	24 h	65	<u>24 h</u>
Total			1083 h

#### Generator Owners, Transmission Owners, and Distribution Providers

The burden on Generator Owners, Transmission Owners, and Distribution Providers to support this effort will include time to provide fault clearing times to Transmission Planners and to review protection system documentation to assess where single points of failure may exist. The method defined in this data request also has been developed to limit the burden on Generator Owners, Transmission Owners, and Distribution Providers by grouping the components for which protection system(s) must be evaluated and by only requiring entities to identify whether single points of failure exist in each component category, rather than documenting all single points of failure. Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the protection system(s) only for locations on the system for which the Transmission Planner has identified that a protection system failure could result in a potential reliability risk. The burden will vary depending on factors such as how recently each protection system was installed or modified and availability of past assessments of protection systems. For more recent installations or modifications there may be less work involved as entities will be more familiar with the protection system design and may require limited documentation review. Older installations may require more time to review documentation to identify where single points of failure exist.

Initial Screening and Identification of Transformers with Through-Fault Protection (Step 2): The estimated time is 8-24 engineer-hours. The time required for this step will vary according to the number of buses owned by the entity, as well as the extent to which standard designs are used on the entity's system.

Provide Maximum Expected Fault Clearing Times (Step 3): The estimated time is 0.5 engineer-hour per bus. The time required for this step will vary according to the number of buses to be evaluated, as well as the extent to which standard designs are used on the entity's system. The number of buses will depend on the number of buses eliminated in step 2.

Review Protection System Documentation (Step 5): The estimated time is 2 engineer-hours per bus. The time required for this step will vary depending on the number of buses to be evaluated, availability of past assessments, the extent to which standard designs are used on the entity's system, and the age and voltage class of the installation. The number of buses to be evaluated will depend on the number of buses eliminated in step 3. The time required for a

bus may be significantly less than 2 engineer-hours if a single point of failure is identified early in the review. The time required for a bus may be significantly more than 2 engineer-hours if no single points of failure are identified.

Provide Actual Fault Clearing Times (Step 7): The estimated time is 1 engineer-hour per bus. The time required for this step will vary according to the number of buses to be evaluated, as well as the extent to which standard designs are used on the entity's system. The number of buses for which clearing times are required will depend on the number of buses eliminated in step 5.

Review Protection System Documentation (Step 10): The estimated time is 4 engineer-hours per bus. The time required for this step will vary depending on the number of buses to be evaluated, the number of Elements connected at each bus, availability of past assessments, the extent to which standard designs are used on the entity's system, and the age and voltage class of the installation. The number of buses to be evaluated will depend on the number of buses eliminated in step 8. If an Element was reviewed in step 5 and no single points of failure were identified it is not necessary to repeat the review for that Element in step 9; if the evaluation of an Element was terminated in step 5 before all component categories were evaluated, then it is necessary to complete the review for the remaining component categories in step 9.

Applying these estimated times to the example in Appendix 1 that illustrates application of the method, the Generator Owners, Transmission Owners, and Distribution Providers in the example in the Transmission Planner's area would spend approximately 900 hours on this data request, as outlined below. The time spent by each of the owners would be proportional to the number of Elements they own that are connected to the buses in the transmission planning area. It is expected that the majority of the time would be spent by the Transmission Owners.

	Estimated time	# of buses	Total time
Step 2	24 h	800	24 h
Step 3	0.5 h/bus	375	188 h
Step 5	2 h/bus	160	320 h
Step 7	1 h/bus	95	95 h
Step 10	4 h /bus	65	<u>260 h</u>
Total			887 h



## Organization Acknowledgement and Approval

### Acknowledgement

The following table represents the information each entity will be providing NERC acknowledging notice of the data request in accordance with the reporting schedule. Acknowledgement will be provided electronically via the NERC project page [Order No. 754](#).<sup>22</sup>

Transmission Planning Entity Contact Information			
Entity Name:			
Contact Name:		Office Phone:	
Title:		Cell Phone:	
Email:		NERC ID:	

<sup>22</sup> NERC Order No. 754 Project Page ([http://www.nerc.com/filez/standards/order\\_754.html](http://www.nerc.com/filez/standards/order_754.html))

## Approval

Each entity, upon the conclusion of providing its response(s) to the data request, shall provide written notification to NERC (electronically<sup>23</sup> or hardcopy) with authorized signature, using the following statement and information as a template. Submission by email will constitute electronic signature of the sender.

<Date>

*NERC – Order No. 754  
C/O Scott Barfield-McGinnis, Standards Development Advisor  
3353 Peachtree Road, Suite 600, North Tower  
Atlanta, GA 08540*

*RE: Order No. 754 – Data Request*

*Dear. Mr. Barfield-McGinnis:*

*Please accept this letter as notice our entity listed below has completed the Order No. 754 data request survey.*

*Authorized entity representative approving the completion of the survey:<sup>24</sup>*

*Entity Name:*

*NERC ID:*

*Authorized by (Name):*

*Title:*

*Date:*

*To the best of my knowledge, the information provided in the response(s) to the Order No. 754 survey is complete and correct in accordance with the data request.*

*Sincerely,*

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<sup>23</sup> Electronic submission shall be emailed to [DataRequest754@nerc.net](mailto:DataRequest754@nerc.net), all other correspondence must use the official address listed in the data request.

<sup>24</sup> This approval should be completed by a company employee, consistent with the entities' process and authorized persons for submitting such data.

## Appendix 1 – Examples<sup>25</sup>

### Example Illustrating Application of the Method

Step 1: A Transmission Planner identifies that it has 800 buses operated at 100 kV or higher as follows:

115 kV	465
138 kV	20
161 kV	15
230 KV	290
<u>500 kV</u>	<u>10</u>
Total	800

Of these 800 buses, 522 meet the criteria in Table A for “Criteria for Buses to be Evaluated.” The numbers of buses on the “List of Buses to be Tested” developed in step 1 are:

115 kV	240
138 kV	12
161 kV	10
230 KV	250
<u>500 kV</u>	<u>10</u>
Total	522

Step 2: After coordinating with its Generator Owners, Transmission Owners, and Distribution Providers, the Transmission Planner is able to eliminate 147 buses based on the asset owners’ knowledge of their protection systems confirming that the protection systems for the Elements connected to the buses and for the physical bus(es), if any, meet the attributes for all categories of components in Table B, “Protection System Attributes to be Evaluated.” The numbers of buses on the initial “List of Buses to be Evaluated” developed in step 2 are:

115 kV	220
138 kV	10
161 kV	8
230 KV	132
<u>500 kV</u>	<u>5</u>
Total	375

<sup>25</sup> These examples are provided only for illustrative purposes and are not indicative of the expected number of buses or protection systems that may meet the criteria and attributes defined in this Request for Data or Information.

Steps 3 and 4: The Transmission Planner simulates a three-phase fault on each of these buses as defined in step 3 and identifies that for 215 buses the simulated system performance based on maximum expected remote clearing times does not exhibit any of the adverse impacts identified in Table C, “Performance Measures.” The “List of Buses to be Evaluated” is revised by removing these buses and the numbers of buses remaining are:

115 kV	55
138 kV	5
161 kV	3
230 KV	92
<u>500 kV</u>	<u>5</u>
Total	160

Steps 5 and 6: The Generator Owner, Transmission Owner, and Distribution Provider review protection systems at the buses remaining on the “List of Buses to be Evaluated” and identify that 95 of the buses have at least one Element connected for which the protection does not meet the attributes in Table B, “Protection System Attributes to be Evaluated.” The numbers of buses on the “List of Buses to be Evaluated” is further reduced as follows:

115 kV	45
138 kV	4
161 kV	2
230 KV	42
<u>500 kV</u>	<u>2</u>
Total	95

Steps 7, 8, and 9: The Transmission Planner obtains actual clearing times and simulates a three-phase fault on each of these buses as defined in step 8 and identifies that for 30 buses the simulated system performance based on actual clearing times does not exhibit any of the adverse impacts identified in Table C, “Performance Measures.” The “List of Buses to be Evaluated” is revised by removing these buses and the numbers of buses in the final “List of Buses to be Evaluated” are:

115 kV	28
138 kV	2
161 kV	1
230 KV	32
<u>500 kV</u>	<u>2</u>
Total	65

Step 10: The Generator Owner, Transmission Owner, and Distribution Provider assess their protection systems and provide data to the Transmission Planner:

- The Generator Owner, Transmission Owner, and Distribution Provider that own Elements connected to any of the buses identified in the final “List of Buses to be Evaluated” (developed in step 9), or the physical bus(es) if any, assess the protection system attributes for each component category in Table B, “Protection System Attributes to be Evaluated.”
- The Generator Owner, Transmission System Owner, and Distribution Provider also evaluate the station DC supply for each bus on the initial “List of Buses to be Tested” (developed in step 1).

Step 11: The Transmission Planner reports the data. An excerpt is provided in the following table of the data the Transmission Planner in this example would report on the Buses Evaluated tab.

Figure 1-1 – Example Data Reported on the Buses Evaluated Tab

Buses Evaluated						
		≥100 kV - <200 kV	≥200 kV - <300 kV	≥300 kV - <400 kV	≥400 kV - <600 kV	≥ 600 kV
1.	Total number of buses in the transmission planning area:	500	290	0	10	0
2.	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for	262	250	0	10	0
3.	Total number of buses evaluated by the Transmission Planner based on actual clearing times:	51	42	0	2	0
4.	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in	31	32	0	2	0
5.	Comments:					

**Notes:**

The numbers of buses entered in row 1 correspond to all buses in the Transmission Planner's area used as the starting point in step 1.

The numbers of buses entered in row 2 correspond to the buses that meet the "Criteria for buses to be Tested" in Table A and are placed on the "List of Buses to be Tested" in step 1.

The numbers of buses entered in row 3 correspond to all buses that are evaluated by the Transmission Planner by simulating a three-phase fault with fault clearing based on actual clearing times in step 8.

The numbers of buses entered in row 4 correspond to all buses that are evaluated in step 8 for which the simulated system performance exhibits one or more of the adverse impacts in Table C and are placed on the final "List of Buses to be Evaluated" in step 9.

### Examples Illustrating Application of the Criteria in Table A

The following figures provide examples of applying the criteria in Table A to determine the initial “List of Buses to be Tested.”

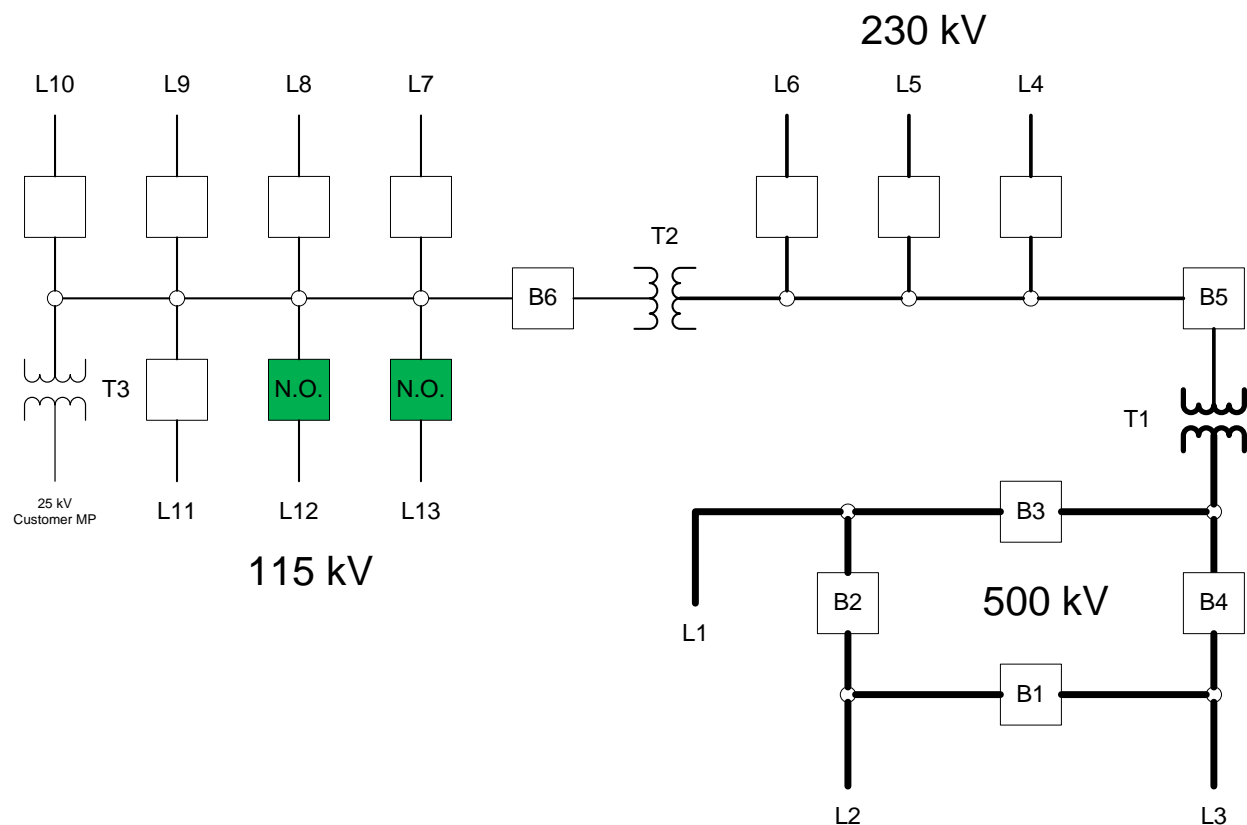
In Figure 1-2, the Transmission Planner would include the 115 kV, 230 kV and 500 kV buses on the “List of Buses to be Tested.”

The 115 kV bus has five transmission lines (L7 through L11) and one 230/115 kV transformer (T2) connected; a total of six circuits connected at 115 kV which meets the second criterion in Table A. Note that for the purpose of applying Table A the normally open transmission lines L12 and L13 and the 115/25 kV step-down transformer do not qualify as circuits.

The 230 kV bus has three transmission lines (L4 through L6), one 500/230 kV transformer (T1), and one 230/115 kV transformer (T2) connected; a total of five circuits connected at 230 kV which meets the first criterion in Table A.

The 500 kV bus has three transmission lines (L1 through L3) and one 500/230 kV transformer (T1) connected; a total of four circuits connected at 500 kV which meets the first criterion in Table A.

Figure 1-2 – Table A Example with Two Straight-Buses and One Ring Bus



In Figure 1-3, the Transmission Planner would exclude the 345 kV and 138 kV buses on the left side of the figure from the “List of Buses to be Tested.” The 345 kV and 138 kV buses on the right side of the figure would be included.

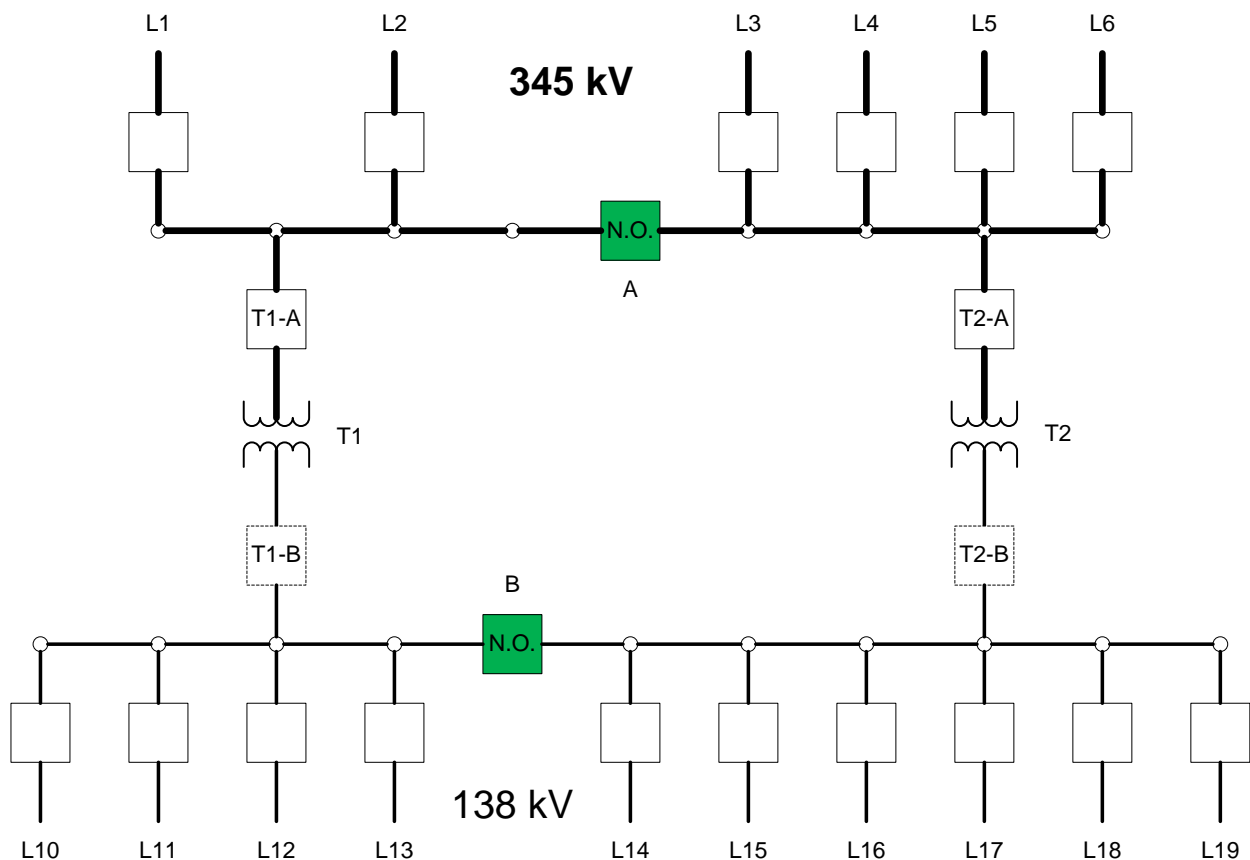
The 345 kV bus on the left has two transmission lines (L1 and L2) and one 345/138 kV transformer (T1) connected; a total of three circuits connected at 345 kV which does not meet any criterion in Table A.

The 345 kV bus on the right has four transmission lines (L3 through L6) and one 345/138 kV transformer (T2) connected; a total of five circuits connected at 345 kV which meets the first criterion in Table A.

The 138 kV bus on the left has four transmission lines (L10 through L13) and one 345/138 kV transformer (T1) connected; a total of five circuits connected at 138 kV which does not meet any criterion in Table A.

The 138 kV bus on the right has six transmission lines (L14 through L19) and one 345/138 kV transformer (T2) connected; a total of seven circuits connected at 138 kV which meets the first criterion in Table A.

Figure 1-3 – Table A Example with Straight-Buses and Normally Open Bus-Ties

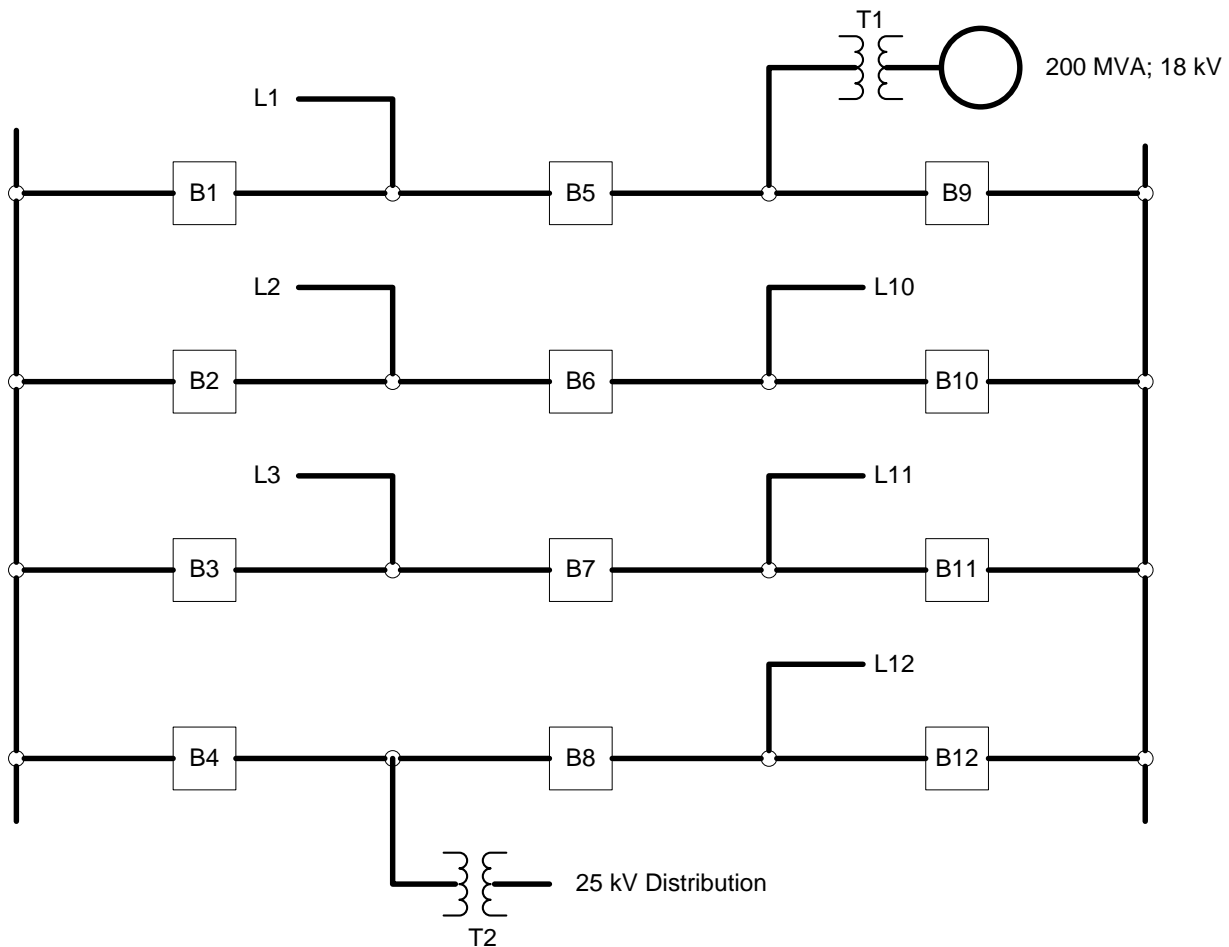




In Figure 1-4, the Transmission Planner would include the bus on the “List of Buses to be Tested,” as long as the bus voltage is 100 kV or higher.

The bus has six transmission lines (L1 through L3 and L10 through L12) and one generator step-up (GSU) transformer (T1) connected; a total of seven circuits connected at 100 kV or higher which meets the first or second criterion in Table A depending on the voltage. Note that for the purpose of applying Table A the step-down transformer does not qualify as a circuit. However, if the step-down transformer is connected to a bus on the final “List of Buses to be Evaluated” the asset owner does need to evaluate the step-down transformer protection system against the attributes in Table B. Also note that the generator step-up transformer qualifies as a circuit because the generator is greater than 20 MVA. If the generator gross nameplate rating was 20 MVA or less, the GSU transformer would not qualify as a circuit.

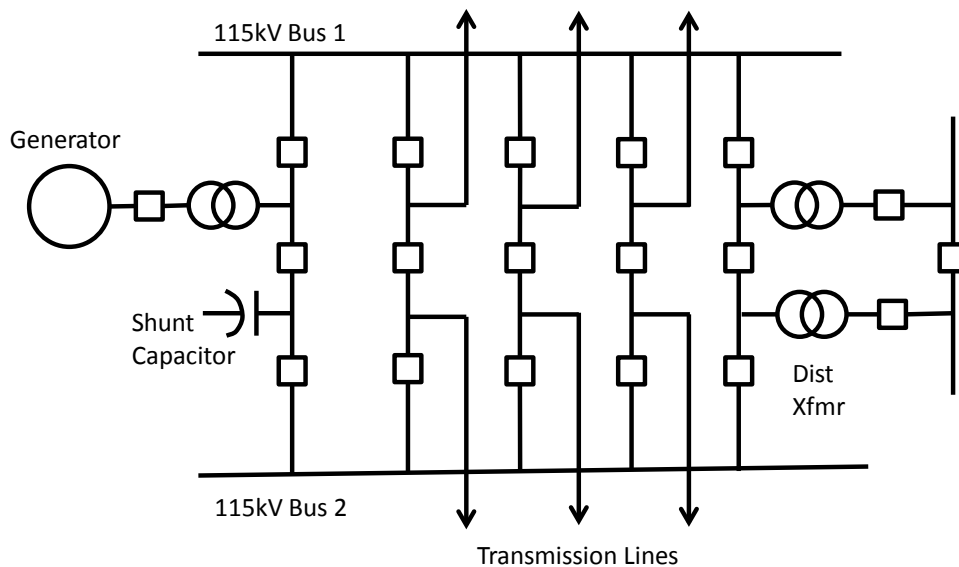
Figure 1-4 – Table A Example with a Breaker-and-a-Half Bus



## Examples Illustrating Application of the Criteria in Table B and Guidance on Determining Clearing Times<sup>26</sup>

Figure 1-5 shows a 115 kV breaker-and-a-half installation with a generator (registered), six non-radial transmission lines, two distribution step-down banks, and a shunt capacitor connected. Since there are seven qualifying circuits (the six lines plus the generator), this is a “Table A” bus. For the Transmission Planner’s three-phase fault simulation, the bus is collapsed into a single node. For analyzing the protection systems, the actual topology must be maintained. Several examples of this analysis are discussed below and illustrated in subsequent figures.

Figure 1-5 – Bus Configuration for Table B Example

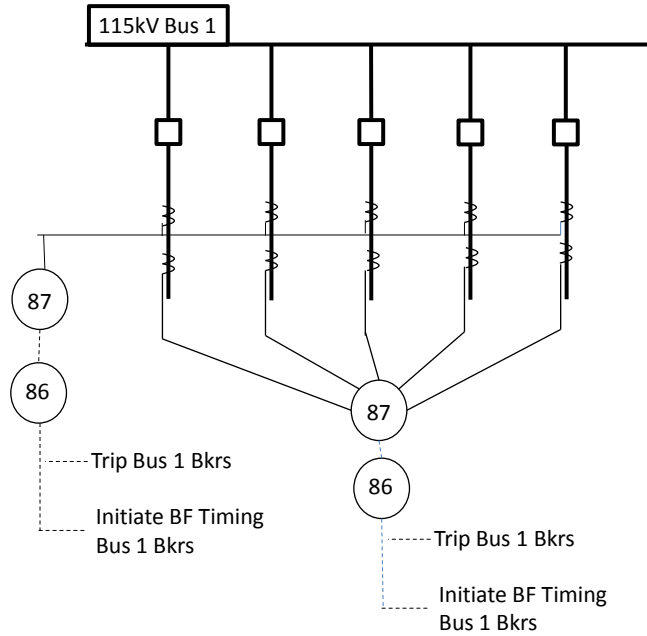


<sup>26</sup> These examples were selected to illustrate concepts discussed in the paper and are not intended to be prescriptive or to suggest preferred methods of protection, nor are they inclusive of all possible methods for providing protection.

**Bus Protection:**

Figure 1-6 illustrates a set of bus differential protection schemes that would result in a protection system with the required attributes of Table B for redundancy. The schemes have separate CT secondary windings, separate protective relays, and separate auxiliary relays. If the auxiliary relays (the lockouts) have separate DC circuits, and operate separate trip coils, this set of schemes meets the necessary redundancy requirements.

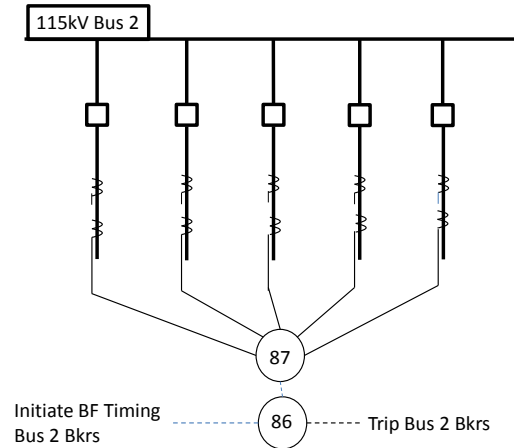
Figure 1-6 – Bus Protection Design Meeting Table B Attributes



Note: Figure 1-6 is a detailed excerpt from Figure 1-5 illustrating the bus protection for 115 kV Bus 1.

Figure 1-7 shows a scheme that in general, does not meet any of the Table B redundancy requirements.

Figure 1-7 – Bus Protection Design Not Meeting Table B Attributes

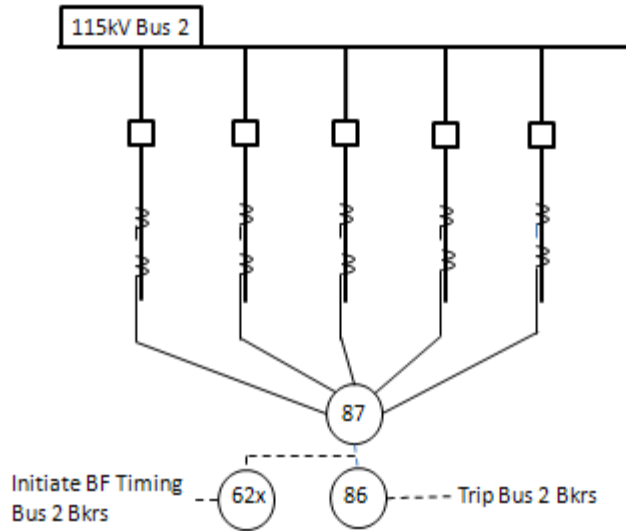


Note: Figure 1-7 is a detailed excerpt from Figure 1-5 illustrating the bus protection for 115 kV Bus 2.

Filling out the template for the breaker-and-a-half installation in Figure 1-5 would yield the following values to be included on the Buses tab for the rows in the 100-200 kV column: for row 1, 2 physical buses evaluated; for rows 2, 3, 5, and 6, the protection system for 1 bus evaluated does not meet the specified attributes.

Figure 1-8 shows the same scheme as the previous, but with a separate auxiliary relay to initiate breaker failure timing. If we assume an electro-mechanical relay scheme using one relay per phase (such as a CA-16 or PVD), this scheme has many interesting characteristics relative to Order 754. For a three-phase fault, there are three separate protective relays, each with its own CT set. Separate auxiliary relays are used for tripping, and for arming breaker failure protection, so a single trip coil should not be an issue. The limitation of this scheme is that it is likely that while the DC circuits of each breaker failure scheme are most probably separate from the bus differential scheme, it is likely that the lockout relay and 62X relay share the same DC source. An estimated 95 percent or more of systems that use separate auxiliary relays for tripping and breaker failure initiation (including separate reed relays in microprocessor relays) probably use the same DC source for both. While this scheme would not have the same failure mode observed in the Westwing event, for the purpose of this survey it does have a single point of failure associated with the DC circuit operating the lockout and auxiliary relay used to initiate breaker failure relaying.

Figure 1-8 – Alternate Bus Protection Design Not Meeting Table B Attributes

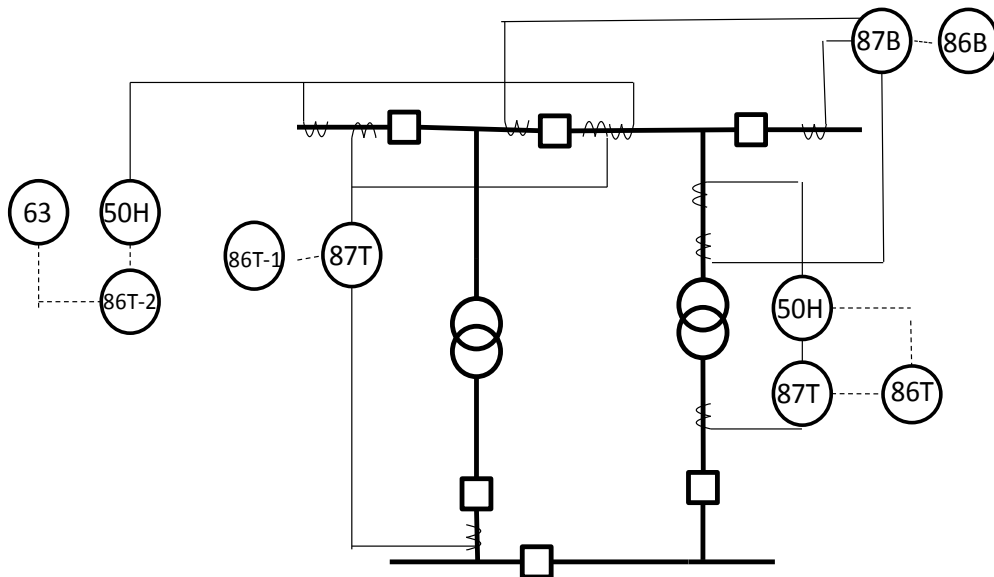


Note: Figure 1-8 is a detailed excerpt from Figure 1-5 illustrating the bus protection for 115 kV Bus 2.

***Distribution Transformers:***

Figure 1-9 illustrates some Order 754 points; it is not intended to be widely representative of typical distribution transformer protection. The faults of interest for this assessment only include faults which are essentially the same as bus faults. It is not necessary to consider faults on the low-side and faults within the transformer with enough impedance between the bus and the fault that an instantaneous overcurrent relay set to operate for a bus fault would not operate.

Figure 1-9 – Step-down Distribution Transformer Example



Note: Figure 1-9 is a detailed excerpt from Figure 1-5 illustrating the step-down transformer protection.

**Right Hand Transformer:** The CTs indicate the zones of protection. The bus, including any lightning arrestors on the high side of the transformer, is protected by a bus differential. The transformer is protected by an instantaneous overcurrent relay and a transformer differential. As drawn none of this is redundant except for the minimal area between the transformer bushing CTs. The situation could be substantially improved if the 50H relay were connected to a redundant set of CTs (not shown) covering the bus. In that case the entire 115 kV bus would be covered by both a bus differential and the 50H, each provided with separate CTs, and tripping through separate lockouts. Faults within the tank, before the winding, would be covered by the 50H and 87T, but they would have a single point of failure as they both trip through the same lockout.

**Left Hand Transformer:** The protection for bus equivalent faults on this transformer meets all the requirements of Table B. The differential protection uses dedicated CTs, and trips through its own lockout. The 50H covers the bus and transformer with dedicated CTs and trips through its own lockout. The 50H lockout is also operated by a fault pressure relay (perhaps an SPR or Bucholtz) which will trip high speed for bus equivalent faults within the tank.

Concerning the reporting template, there are two step-down transformers evaluated here. Therefore, the entry in row 1 on the Step-down Transformers tab in the 100-200 kV column would include 2 step-down transformers. The left hand transformer meets the redundancy requirements of Table B and the right hand transformer does not, so 1 would be included in row 2 under the 100-200 kV column. The bus associated with the left hand transformer is entirely covered by the transformer protection; however, this would not be reported on the Buses tab as indicated in Note 1 on the Buses tab.

As drawn, the right hand transformer would have 1 included on rows 5 and 6. If the 50H relay were wrapped around the bus, there would still be 1 included in row 6, due to the common lockout relay. The single bus differential scheme would be handled on the bus tab. If the 50H relay were connected to CTs covering the bus, this installation would meet all requirements for Table B (relative to the bus). As drawn, the bus has multiple single points of failure.

### ***GSU Transformers:***

Analysis of the protection for GSU transformers is similar to distribution transformers in that only protection systems required to clear bus equivalent (high-side) faults need to be redundant. Unlike distribution transformers however, GSU transformers have a source behind them. If a single point of failure exists, clearing time from behind the GSU needs to be used in the planning study. In many cases with very large generators, there is no low side breaker. When there is a fault in the GSU zone the generator is tripped from the high side, excitation is tripped, but permanent magnetization remains in the rotor iron. The generator will contribute to the fault until it spins down to a stop. However, this fault contribution will not contribute to the overall system performance once the rest of the system is cleared from the GSU.

Figure 1-10 shows a typical arrangement for a large generator connected to a bus. The generator and GSU transformer are often significantly displaced from the switchyard and

because of this, protection systems on the GSU transformer are also often located apart from each other (i.e., switchyard and generator). This is the case illustrated in Figure 1-11.

Figure 1-10 – Detailed View of Generator Connection

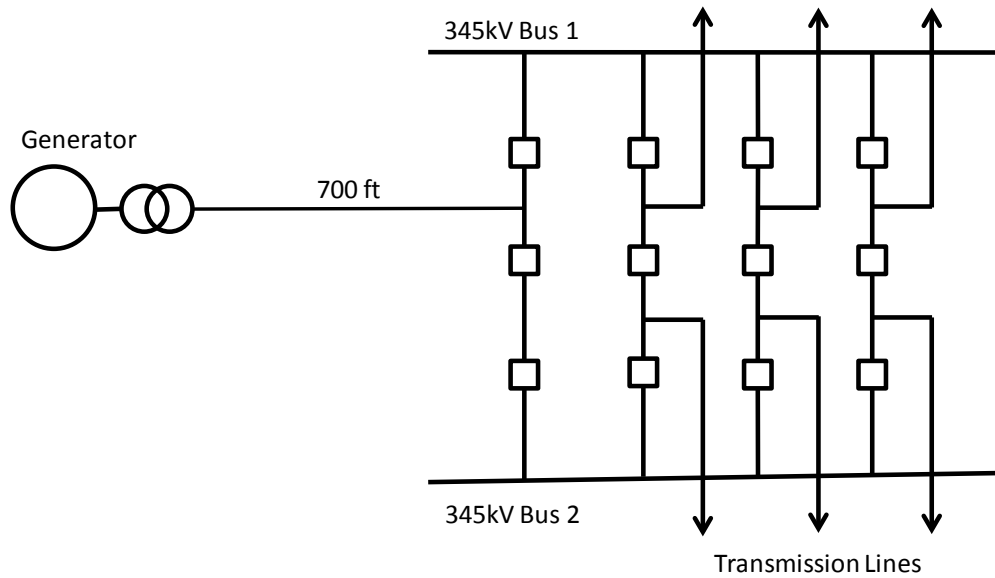
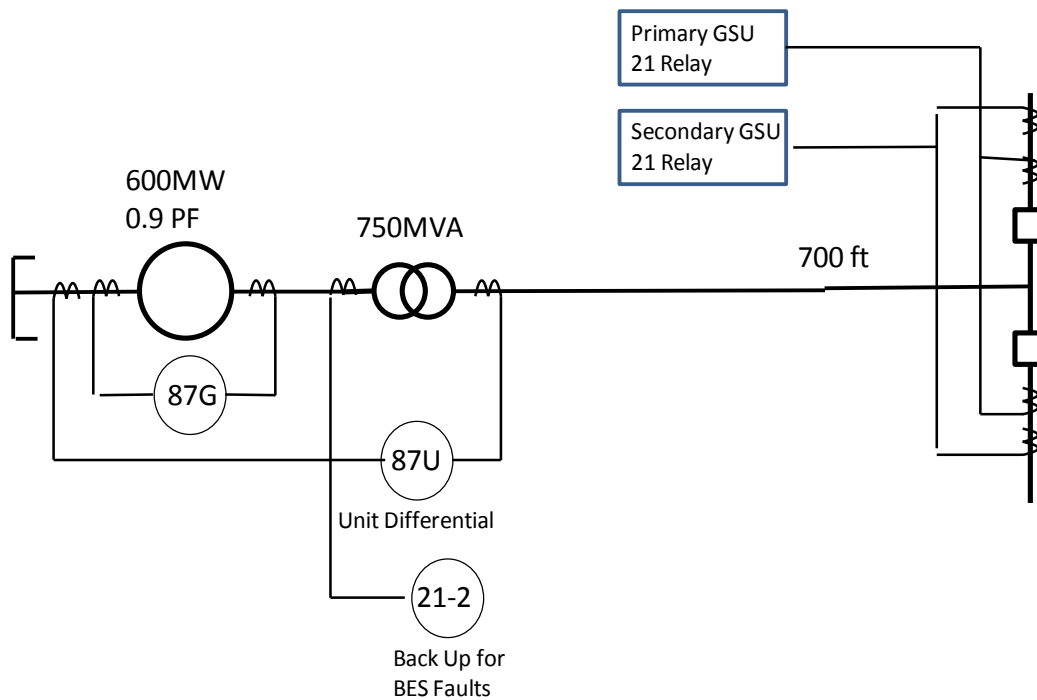


Figure 1-11 – Detailed View of Selected Generator and GSU Transformer Protection



Note: Figure 1-11 is a detailed excerpt from Figure 1-10 illustrating the generator step-up (GSU) transformer protection.

GSU Impedance Relays (21) – These relays are typically located in the 345 kV switchyard control house where they are closer to the CTs, VTs, and breaker trips coils. The zone 1 impedance elements typically reach into, but not beyond the GSU. If they consist of a primary and secondary pair, connected to redundant CTs and PTs, and trip separate trip coils, these will meet the redundancy attributes of Table B. In this example, communication systems are not used for these applications.

Generator and Unit Differentials – These relays are typically located in the plant. They provide protection for the generator (redundant) and the GSU transformer (not redundant – only the unit differential covers the GSU transformer). Faults within the GSU transformer that are essentially bus magnitude faults, are covered by the unit differential, and by the GSU impedance relays located in the switchyard (discussed above). In addition, there may be a dedicated GSU transformer differential, instantaneous overcurrent, and fault pressure relays applied to the GSU transformer.

Generator Back-Up Relays (21-2) – These relays are typically located in the plant. An impedance relay on the low side of the GSU transformer is shown. Voltage-controlled or voltage-restrained over current relays are sometimes used as an alternative to the impedance relay. These relays determine the back-up tripping times for the source behind the GSU transformer for uncleared faults on the transmission system.

Generator and GSU Relays Not Subject to the Data Request – There are many devices applied in generation plants that are not subject to the data request. These include loss of field relays, V/Hz relays, negative sequence relays, reverse power relays, and other devices which are not intended to clear faults on the transmission system.

***Shunt Devices:***

In the case of large reactors, especially reactors in oil filled tanks, the relay redundancy analysis will be similar to distribution transformers. Smaller air core reactors are more commonly found on autotransformer tertiary windings than on transmission buses or lines, and therefore not an issue. In the case of shunt capacitors, voltage unbalance and neutral current unbalance schemes, which are typically used to provide protection for small failures within the array of capacitors, are not suitable for responding quickly to single-line-to-ground or three-phase faults at the capacitor. Usually there will be instantaneous overcurrent relaying for these faults for which single points of failure must be considered. As such, when evaluating whether capacitor bank protection meets the attributes in Table B, one scheme that detects single-line-to-ground and three-phase faults at the capacitor and one scheme that detects unbalance within the bank would not meet the attributes in Table B.

***Radial Transmission Lines:***

If a line is radial and the only Elements connected to the line are transformers that step down to a voltage below 100 kV, the line is not counted as a circuit when applying Table A to identify the initial “List of Buses to be Tested.” However, if the radial line is connected to a bus on the final “List of Buses to be Evaluated” the asset owner does need to evaluate the protection system against the attributes in Table B.

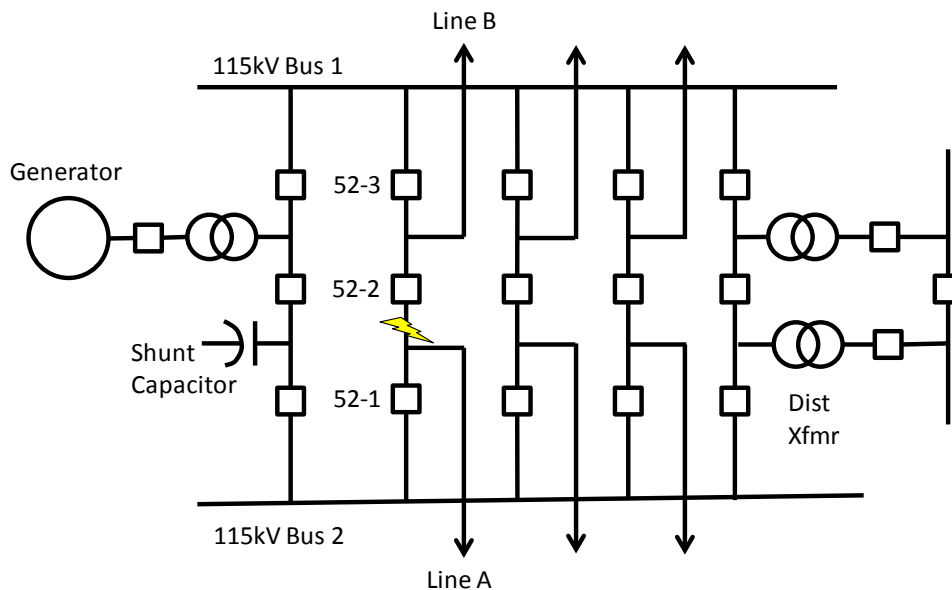


**Transmission Line Single Points of Failure and Resultant Clearing Times:**

Faults on Line A as shown in Figure 1-12 will be discussed for two protection system variations, and several representative single points of failure. The fault will be located on the bus section between breakers 52-1 and 52-2. This is a line fault with essentially identical fault currents as a fault on either of the two main buses. In general, different protection systems, as well as different single points of failure within the protection systems will result in different remote clearing times. For this example, clearing times for the shunt capacitor and distribution transformers will be ignored, as they are not sources to the fault. Both line breakers have breaker failure schemes which will operate outputs in 10 cycles.<sup>27</sup> All breaker clearing times are 3 cycles.<sup>28</sup> Line B has a remote clearing time of 25 cycles. All other lines have remote clearing times of 20 cycles.

Note that while examples are provided to identify the clearing times for a single point of failure in each component category for which a single point of failure exists, step 8 requires the Transmission Planner to simulate only one three-phase fault. Typically the fault clearing for this simulation is based on the actual fault clearing for a failure of the protection system to initiate tripping and breaker failure protection. However, some exceptions exist such as if the only single point of failure is in the communication system; or in the case where the only single point of failure is the circuit breaker trips coils and breaker failure protection is provided, in which case the actual fault clearing would be based on operation of the breaker failure protection.

Figure 1-12 – Clearing Times for Transmission Line Fault with Single Point of Failure

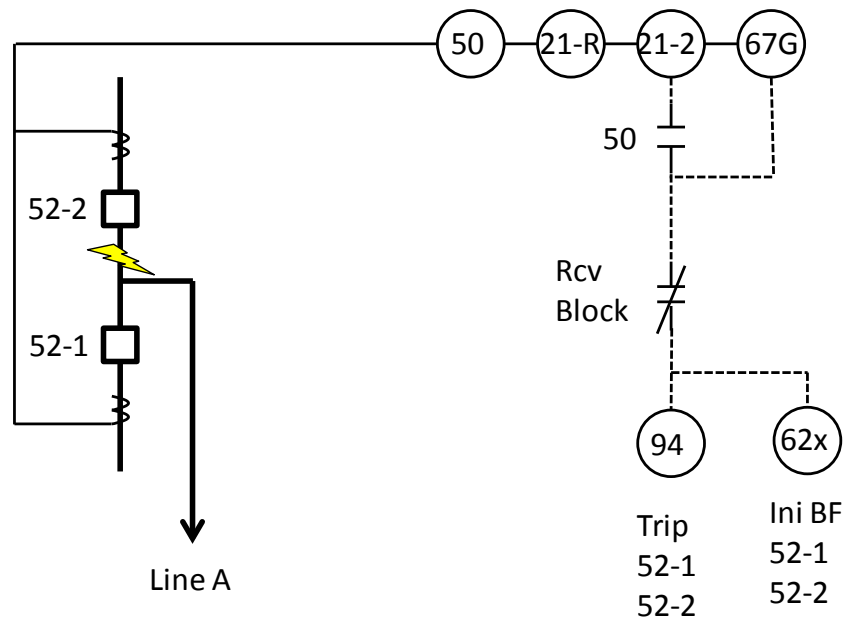


<sup>27</sup> The 10 cycle time from fault inception to breaker failure outputs consists of fault detection and breaker failure initiation time (2 cycles), breaker failure delay setting (7 cycles), lockout operation (1 cycle). In practice actual operating times or best estimates should be used.

<sup>28</sup> Although clearing typically occurs faster than nominal breaker operating time, nominal times are typically used in planning studies, and provide a more conservative study.

**Case 1:** Line A has the simple directional comparison blocking (DCB) scheme shown in Figure 1-13 with no back-up scheme. The protective relays and auxiliary relays share a common DC circuit. Breakers 52-1 and 52-2 both have single trip coils connected to DC circuits separate from each other, and from the line relaying scheme. Both breakers have breaker failure relaying. This example has multiple single points of failure in various component categories for illustrative purposes and is not necessarily what is commonly implemented for protection of transmission lines.

Figure 1-13 – Simple Directional Comparison Blocking Scheme with No Back-up



Note: Figure 1-13 is a detailed excerpt from Figure 1-12 illustrating the transmission line A protection for case 1.

1) All of the following single points of failure will have the same result:

- Failure of the 50 relay to operate.
- Failure of the 21-2 relay to operate.
- Failure of the communication system resulting in a permanent block received.
- Failure of the protective relay DC circuit.

The net result of any of these single points of failure is that no tripping commands or breaker failure initiates will occur. High speed tripping will occur at the remote end of Line A, as it will not receive a block. Line B will clear in 28 cycles (25 cycle relay time + 3 cycle breaker time). The other lines will clear in 23 cycles. The generator source will clear according to its back up characteristics. If it uses an impedance relay set to not overreach the adjacent line zone 1 elements, this may also be in the 25 cycle range.

2) Failure of the Tripping Relay (94) – If the 94 relay fails no tripping commands will be issued, but breaker failure relaying will be initiated on 52-1 and 52-2. The remote end of Line A will trip high speed. The generator and all other lines, except Line B, will clear in 13 cycles due

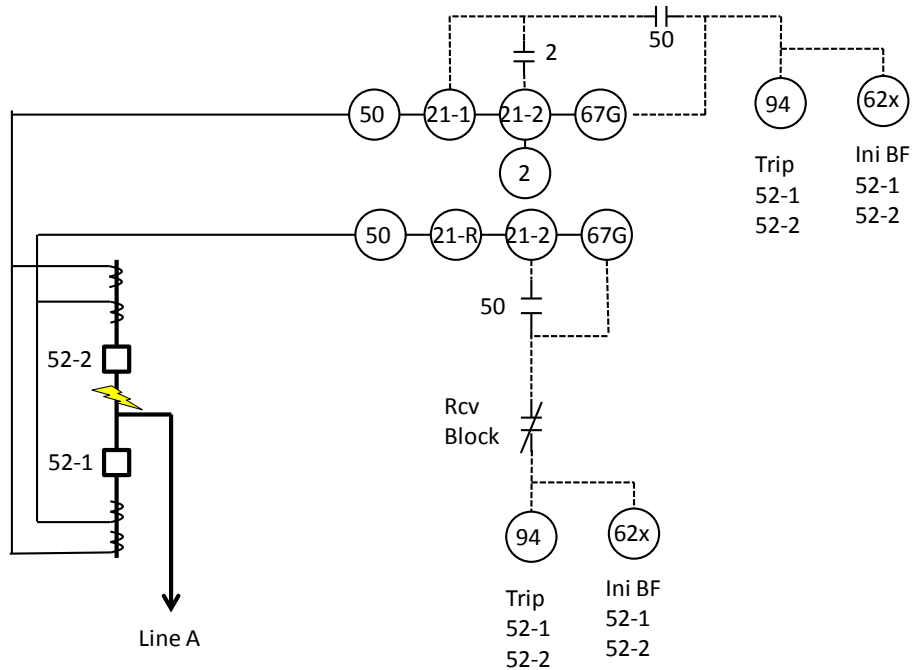
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to breaker failure protection. Remote clearing of Line B will depend on whether or not it is transfer tripped by the breaker failure protection. If it is, it will clear in about 14 cycles. If not, it will clear in 28 cycles.

- 3) Failure of 52-2 Trip Coil or DC circuit breaker – Breaker 52-1 and the remote end of Line A will trip high speed. The generator and all other lines, except Line B, will clear in 13 cycles due to breaker failure protection. Remote clearing of Line B will depend on whether or not it is transfer tripped by the breaker failure protection. If it is, it will clear in about 14 cycles. If not, it will clear in 28 cycles.
- 4) Failure of 52-1 Trip Coil or DC circuit breaker – Breaker 52-2 and the remote end of Line A will trip high speed. The generator and all other lines, including Line B, will clear in 13 cycles due to breaker failure protection.
- 5) Failure of AC Circuits – AC circuits have various failure modes that are difficult to predict. If the failure exists undetected before the three-phase fault, unless it consists of a total loss of all voltage or current sources, the scheme may still trip. If a failure of a single AC circuit occurs during the event then the scheme may still trip. If a pre-existing failure is detected, it may also trip. However, for this study the worst case response is required and therefore AC failures must be considered to result in relay failure to trip.

**Case 2:** An independent stepped distance scheme is added to the DCB scheme on Line A as shown in Figure 1-14, and second trip coils and DC circuits are added to breakers 52-1 and 52-2. This scheme now meets all of the Table B redundancies, except for communication schemes.<sup>29</sup> Although the scheme does not meet the communication redundancy requirements of Table B, a single point of failure of any aspect of communications in that scheme, cannot of itself prevent high speed local clearing of the fault.

Figure 1-14 – Directional Comparison Blocking Scheme/ Stepped Distance Back-up



Note: Figure 1-14 is a detailed excerpt from Figure 1-12 illustrating the transmission line A protection for case 2.

<sup>29</sup> Table B only requires redundant communication schemes when the successful operation of the piloted scheme is necessary to meet TPL standard requirements.