Requests for Clarifications
And Responses
Order No. 754 – Data Request
The Study of Single Point of Failure

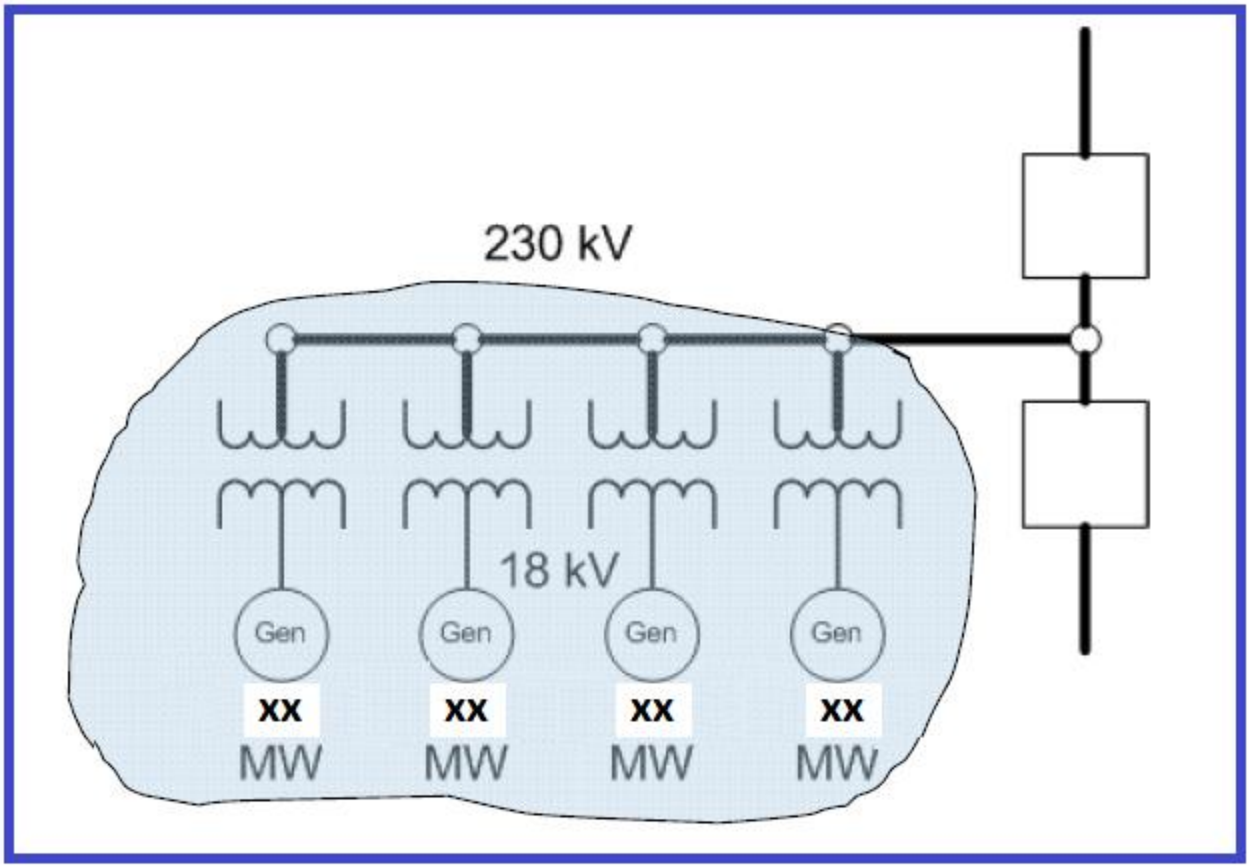
Revised: July 12, 2013

Introduction

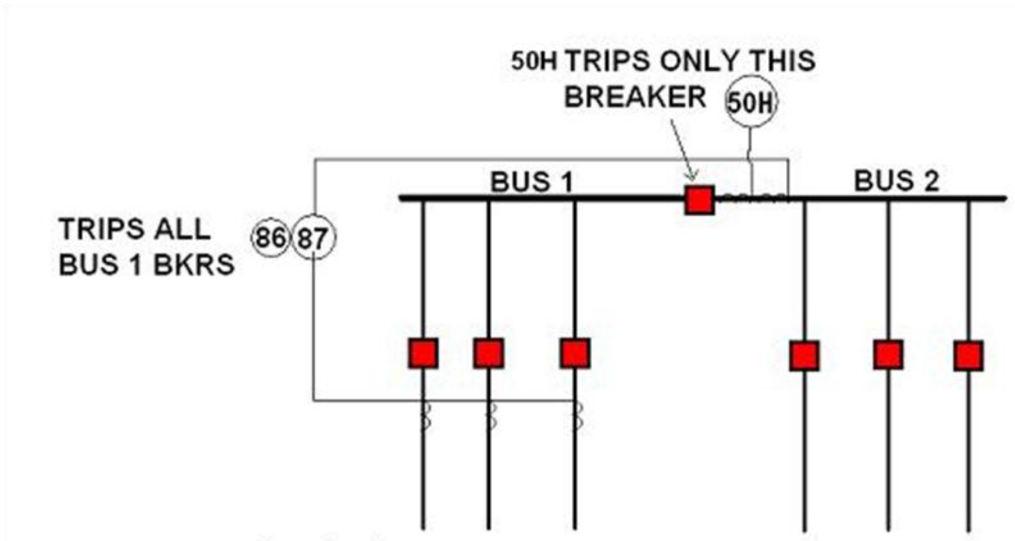
The following information includes requests for clarification concerning the NERC Order No. 754, Request for Data or Information, The Study of Single Point of Failure. Responses are a collaborative effort of NERC staff and selected members of both the System Analysis and Modeling Subcommittee (SAMS) and the System Protection and Control Subcommittee (SPCS). NERC posts this information periodically for entities to review and apply to its efforts in collecting the required data concerning the data request. From time to time, NERC will issue announcements to update Transmission Planners when new clarifications are available. The supporting entities, Distribution Provider, Generation Owner, and Transmission Owner will be included in these announcements.

Step 1

Step 1 Q1. In the example below, please provide guidance in regards to Table A of the Request for Data or Information. Would this generator collector bus with four GSU transformers that has one connection to the substation bus be counted as one GSU transformer or as four GSU transformers?



Step 1 A1. For the purpose of applying Table A it is necessary to determine the number of circuits connected to a bus. In this figure, the generator collector bus with four GSU transformers connected to the 230 kV substation bus via a single connection would be counted as one circuit.



Step 1, Q2. (See figure above) For the purposes of the NERC 754 request – List of Buses to be Tested, does this configuration count as 2 buses with 4 terminals each, or is this one bus with 6 terminals?

With the 50H in-service, a bus section 1 fault with a single-point 86 or 87 failure trips the far terminals from bus 1 and the main bus sectionalizing breaker via the 50H. If the 50H relay did not exist, a bus section 1 fault with a single-point 86 or 87 failure trips the far terminals from both bus 1 and bus 2.

Step 1, A2. (See figure above) For the purposes of this testing, this bus configuration would be treated as a single bus because the sectionalizing breaker is operated normally closed. The existence of protection that would trip the sectionalizing breaker for a bus fault is not considered in this determination, but may be considered by the Transmission Planner when simulating faults.

Whether the Transmission Planner can simulate operation of the protection on the sectionalizing breaker depends on the method used to collect the required data. If the Transmission Planner uses the conservative method (as outlined in the data request) that simulates only one bus fault, the simulation should be based on no local protection operating. In this case the fault would be cleared remotely by all six lines and the simulated bus fault would be representative of the power system performance for a fault on either bus section as well as a fault adjacent to the bus on any element. If the Transmission Planner chooses to perform more detailed analysis for a given substation, he or she must identify all single points of failure that would affect clearing of faults on or immediately adjacent to the bus under study. The Transmission Planner must then study all faults (not just bus faults) for which an identified single point of failure has an impact. This must be done to assure that the worst case power system performance is identified.

Step 3

Step 3, Q1. Facility Selection Criteria – How should entities treat facilities that are in the near-term transmission planning horizon case used by the Planning Coordinator that have not been placed in-service prior to the relevant reporting date in the Reporting Schedule in the data request; e.g., September 30, 2013 for buses operated at 300 kV or higher?
Step 3, A1. Entities should report data for all facilities in the near-term transmission planning horizon case used by the Planning Coordinator. The case closest to modeling year 2013 was specified in the data request to include collection of data for planned new facilities and planned facility upgrades. Entities should provide protection system information based on the protection system attributes expected to be in-service in the time period modeled in the near-term transmission planning horizon case. This includes protection systems on facilities that have not been placed in-service prior to the reporting date as well as protection systems on existing facilities for which upgrades are planned. Please note that the time period modeled may vary for the three reporting periods. As noted in the data request, it is recognized due to the staged reporting approach the assessments for all voltage levels may not occur in the same year and may be based on different Near-Term Transmission Planning Horizon representations.
Step 3, Q2. Fault Location and System Performance Measures – When evaluating transformer protection, to what extent must an entity consider through-faults that occur on the low-side of a distribution transformer or the tertiary of an autotransformer (e.g., at the 13.8 kV terminals of a 345/115/13.8 kV transformer)? Is the data request concerned with the potential tripping of an autotransformer resulting from back-up clearing for a through-fault on the tertiary?
Step 3, A2. The Transmission Planner is only required to simulate three-phase faults on buses operating at 100 kV or higher. Similarly, Transmission Owners, Generator Owners, and Distribution Providers only need to consider protection systems that will detect faults on these buses and faults that are essentially the same as bus faults (e.g., a fault between a circuit breaker and high-side transformer bushing). The single point of failure analysis is intended to identify locations with the potential for a protection system failure resulting in one of the adverse consequences in Table C (i.e., loss of synchronism of multiple generating units, loss of synchronism between portions of the system, or undamped oscillations). The potential reliability impact of backup protection removing an autotransformer from service for a through-fault on the tertiary is outside the scope of this data request.
Step 3, Q3. Section 3 of the data request procedure states: “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."   Is it permissible to clear the fault by opening up all of the facilities on the other side of the transformer?
Step 3, A3. For entities following the method in the data request it is not permissible in step 3 to open all facilities on the other side of a transformer that does not have though-fault protection. This is because the determination of the maximum expected clearing times used in this step does not include analysis necessary to confirm that the remote backup protection on each of the facilities will reach through the transformer to detect the fault. However, when using expected clearing times in step 8, it is intended that the facility owner has confirmed whether the remote backup protection is able to reach through the transformer and detect the fault, while accounting for infeed. Therefore, it is permissible in step 8 to trip each facility for which the ability of remote protection to detect the fault has been confirmed; however, this may still not result in opening all of the facilities on the other side of the transformer. Since the data request permits entities to use an alternate method that yields the requested data, tripping of appropriate facilities using the above approach for step 8 is also permissible in any alternate method that uses expected clearing times.

Table A

Table A, Q1. Facility Selection Criteria – How should entities treat facilities that are in the near-term transmission planning horizon case used by the Planning Coordinator that have not been placed in-service prior to the relevant reporting date in the Reporting Schedule in the data request; e.g., September 30, 2013 for buses operated at 300 kV or higher?
Table A, A1. Entities should report data for all facilities in the near-term transmission planning horizon case used by the Planning Coordinator. The case closest to modeling year 2013 was specified in the data request to include collection of data for planned new facilities and planned facility upgrades. Entities should provide protection system information based on the protection system attributes expected to be in-service in the time period modeled in the near-term transmission planning horizon case. This includes protection systems on facilities that have not been placed in-service prior to the reporting date as well as protection systems on existing facilities for which upgrades are planned. Please note that the time period modeled may vary for the three reporting periods. As noted in the data request, it is recognized due to the staged reporting approach the assessments for all voltage levels may not occur in the same year and may be based on different Near-Term Transmission Planning Horizon representations.

Table B

Table B, Q1. When evaluating communication systems associated with transmission line protection systems, is it necessary for communication channels to have diverse paths to be considered independent for the purposes of meeting the attributes in Table B?
Table B, A1. Entities do not need to consider path diversity when evaluating whether communication systems meet the attributes in Table B. For the purposes of this data request, physical separation of protection system components is not necessary for protection system components to be reported as independent.
Table B, Q2. Some generating plant Main Power Transformers have 3 independent relays (GE BDD); one per phase connected to a single set of CTs at the generator breaker. My thinking is for a 3 phase fault, there is redundancy with the relays (each one on its own phase) but I am not sure that having each relay being supplied input from a single set CTs is considered redundant. Would it make a difference if the CTs are wired delta or wye?
Table B, A2. The intent of the method in the data request is to use a three-phase fault to simplify the analysis by studying a credible worst-case system condition. However, the data collection is focused on all single points of failure and the attributes in Table B are not specific to three-phase faults. Therefore, one set of single phase relays and one set of single phase CTs would not meet the intent of the attributes in Table B. The CT connections (wye or delta) would not have a bearing on this determination. Entities may provide additional information in the comment field to describe situations where one set of relays mitigates or eliminates the potential for non-operation of a protection system due to a single point of failure. A discrepancy with instruction 7 on the reporting template has been identified and a revised reporting template has been posted to clarify that facility owners will assess single points of failure based on protection system operation for all fault types.
Table B, Q3. On some installations for bus protection, a single set of CTs is utilized with single-phase current differential relays in series with single-phase instantaneous overcurrent / time delay relays. Each of these systems is connected to independent DC systems that include the following: 125 V dc battery sets / chargers and control circuitry (including tripping relays).
Table B, A3. The intent of the method in the data request is to use a three-phase fault to simplify the analysis by studying a credible worst-case system condition. However, the data collection is focused on all single points of failure and the attributes in Table B are not specific to three-phase faults. Therefore, one set of single phase relays, one set of single phase CTs, and separate dc circuitry for each phase would not meet the intent of the attributes in Table B, even though the only condition that a single point of failure would prevent this design from detecting is a single phase fault. Entities may provide additional information in the comment field to describe situations where one set of relays mitigates or eliminates the potential for

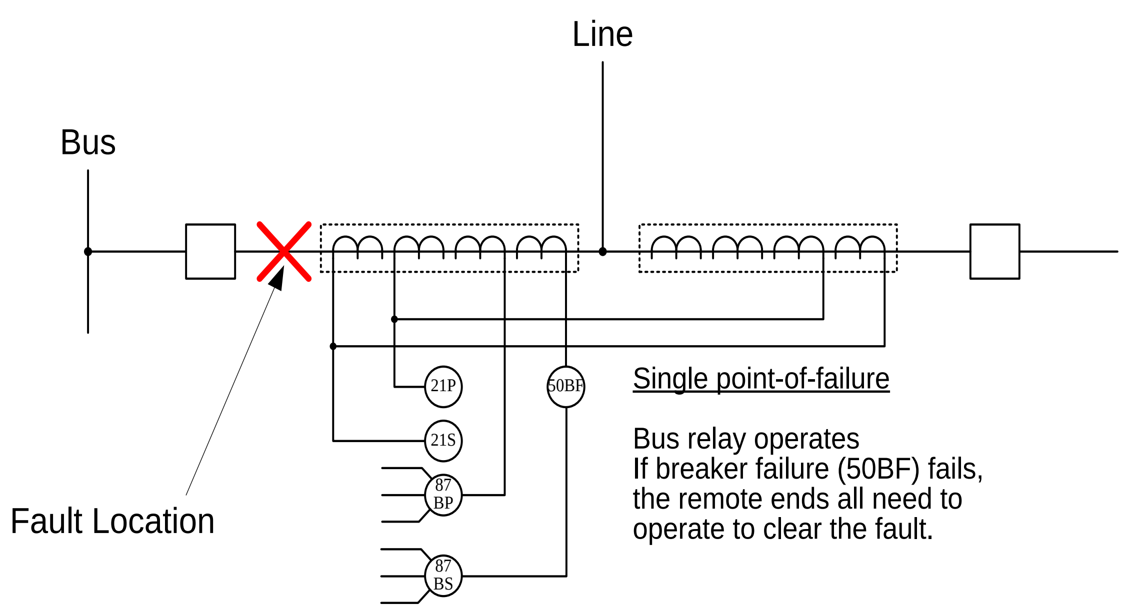
non-operation of a protection system due to a single point of failure. A discrepancy with instruction 7 on the reporting template has been identified and a revised reporting template has been posted to clarify that facility owners will assess single points of failure based on protection system operation for all fault types.
Table B, Q4. Our transmission transformers (i.e., autotransformers) are three-phase, single-tank design. The current differential and sudden pressure relays are installed to detect internal transformer faults. Each of these systems is connected to independent DC systems that include the following: 125 V dc battery sets / chargers and control circuitry (including tripping relays).
Table B, A4. A sudden pressure relay and a differential relay meet the intent of Table B and may be considered as two independent protective relays to detect faults inside the transformer tank. However, to meet the attributes in Table B, two independent protective relays would be necessary to detect faults outside the tank, but within the transformer protection zone.
Table B, Q5. Please provide guidance on data reporting for facilities that utilize live-tank breakers and free-standing CTs. Unlike dead-tank breakers, this application does not provide the classic, over-lapping zones of protection and relies on the breaker failure protection for clearing a fault between the breaker and the free-standing CT. In the example below, the fault is in the bus protection zone; however, opening the bus breakers does not clear the fault and the fault remains outside the line protection zone. Generally accepted industry practice is to provide non-redundant breaker failure and CT column ground protection. Does this affect whether the bus and line protection systems meet the attributes in Table B? 

Table B, A5. It is generally accepted in the industry that a fault in the location shown is a very low probability occurrence and it is standard industry practice to utilize one breaker failure relay and one CT column ground relay. The data request is not collecting information on this known condition, as it could skew the protection system attribute data being reported for buses, transmission lines, transformers, and shunt devices.

Table C

Table C, Q1. Assume that a bus that is being analyzed in the Eastern Interconnection has more than 2000 MW of generation directly connected to it. Assume that remote clearing times for the lines connected to this bus will all clear in 30 cycles. If the generation connected to this bus, which exceeds 2000 MW, all goes unstable in 10 cycles does this constitute failure of the Table C performance test? This generation would have otherwise been remotely cleared in 30 cycles. Table C does not speak to the timing issue of the units going unstable but only states “Loss of synchronism of generating units totaling greater than 2000 MW.” The generation could be considered consequential generation loss.
Table C, A1. The criteria in Table C apply to the portion of the system remaining after fault clearing. In the example proposed, the generation that loses synchronism in 10 cycles, but is disconnected from the system due to protection systems operating to isolate the fault at 30 cycles, would not be counted toward the 2000 MW threshold in the first criterion in Table C.

Version History

Version	Date	Action	Change Tracking
1.0	9/30/2012	Step 1, Q1	New
2.0	11/2/2012	Table B, Q1	Appended
3.1	12/20/2012	Table C, Q1	Appended
4.0	1/30/2012	Step 3, Q1 – Facility Selection Criteria Step 3, Q2 – Fault Location and System Performance Measures	Appended
5.0	4/30/2013	Step 1, Q2– Terminal count Step 3, Q3 – Through faults Table B, Q2, Q3, Q4 – Redundancy	Appended
6.0	7/12/2013	Table B, Q5 – Redundancy	Appended