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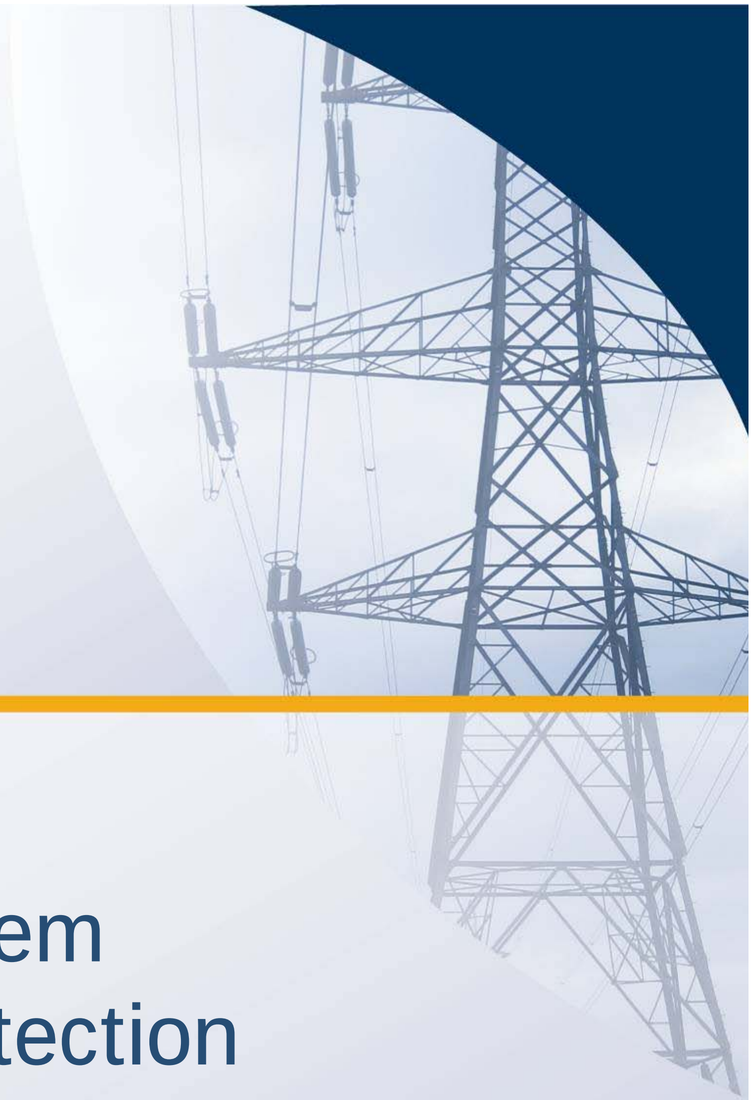
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Reliability Guideline

Transmission System Phase Backup Protection

NERC System Protection and Control Subcommittee

to ensure the reliability of the bulk power system

June 2011

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This Reliability Guideline was approved by the NERC Planning Committee on June 8, 2011.

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1. Introduction and Need to Discuss Backup Protection

Backup protection can, and in many cases does, play a significant role in providing adequate system performance or aiding in containing the spread of disturbances due to faults accompanied by Protection System failures or failures of circuit breakers to interrupt current. However, NERC protection standards affect and may limit the use of backup protection to ensure that backup protection does not play a role in increasing the extent of outages during system disturbances. A number of significant system disturbance reports since the 2003 Northeast Blackout have recommended evaluating specific applications of adding backup and/or redundant protection to enhance system performance or contain the extent of a disturbance. The most significant of these is the FRCC report from the February 26, 2008 system disturbance titled "*FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26th, 2008 at 1:09 pm*". This report states that "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection for autotransformers". As a result the NERC Planning Committee (PC) has assigned the NERC System Protection and Control Subcommittee (SPCS) the task of developing a document on backup protection applications.

The goal of this reliability guideline[1] is to discuss the pros, cons, and limitations of backup protection, and include recommendations, where deemed appropriate, for a balanced approach to the use of backup relaying as a means to ensure adequate system performance and/or to provide a system safety net to limit the spread of a system disturbance for events that exceed design criteria, such as those involving multiple protection system or equipment failures. The document provides a discussion of fundamental concepts related to phase backup protection for the most common equipment on the power system: transmission lines and autotransformers. The document is not intended to provide a comprehensive discussion of all methods used for providing backup protection.

[1] Reliability Guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not standards, binding norms, or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

2. Background on NERC SPCS Activities Related to Backup Protection

The use of backup protection and the implications of its use on the power system is a subject that has been discussed many times by the NERC SPCS since its formation as a NERC Task Force[2] after the 2003 Northeast Blackout. Overreaching or backup phase distance relays providing primary and/or backup functions played a role in the cascading portion of the 2003 Northeast Blackout and have played similar roles in other previous and subsequent blackouts.

The SPCS has done much work with respect to backup protection or issues that affect the use of backup protection. One of the first SPCTF reports was on the "Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems."[3] This paper discussed the pros and cons of the use of Zone 3 type backup protection in a general sense. The Protection System Reliability Standard developed as a result of the 2003 Northeast Blackout, PRC-023-1 "Transmission Relay Loadability," codified requirements for loadability of phase responsive transmission relays which in some cases significantly limited the ability of some relays to provide backup protection. This led to other SPCTF papers illustrating ways to use legacy and modern protective relays to increase relay loadability while meeting protection requirements.

The SPCTF reference paper "Protection System Reliability"[4] was created to accompany the SAR for a new standard to set the acceptable level of redundancy required in Protection System designs to meet system performance requirements. A new standard is currently being considered under a Standard Authorization Request (SAR) submitted by the SPCS. The Protection System Reliability paper discusses the potential use of local and remote backup Protection Systems to provide redundancy, but purposely does not go into detail regarding all the complexities involved in the use of remote backup protection.

The "Power Plant and Transmission System Protection Coordination"[5] Technical Reference Document describes a number of backup protection elements that may be applied on generators and how to ensure adequate coordination and loadability of these elements. These SPCS efforts, other SPCS efforts, and experiences from other events since the 2003 Northeast Blackout point to a need to address the technical details behind the pros and cons of applying backup protection in greater detail in this technical paper.

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[2] The System Protection and Control Task Force (SPCTF), formed in 2004, was the predecessor to the System Protection and Control Subcommittee (SPCS).

[3] Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems – A Report on the Implications and Uses of Zone 3 Relays, February 2, 2005.

[4] Protection System Reliability – Redundancy of Protection System Elements, December 4, 2008.

[5] Power Plant and Transmission System Protection Coordination – Revision 1, July 30, 2010.

3. Terminology Used In This Document

3.1. Redundancy

In the context of this paper, redundancy is the existence of separate Protection System components, as discussed in the NERC SPCS Technical Reference Document "Protection System Reliability," installed specifically for the purpose of meeting the NERC system performance requirements during a single Protection System failure.

It is not the goal of this paper to specify detailed methods to design redundancy into a Protection System. Other papers, including the NERC document cited above and the IEEE Power System Relaying Committee (PSRC) Working Group I19 document "Redundancy Considerations for Protective Relay Systems,"[6] provide detailed discussion of methods to design redundancy into a Protection System.

3.2. Backup Protection

In the context of this paper, backup protection consists of any Protection System elements that clear a fault when the fault is accompanied by a failure of a Protection System component or a failure of a breaker to interrupt current. Backup protection may operate because it is intentionally set to meet specific performance requirements or it may operate for conditions when multiple contingencies have occurred that bring the event into the backup zone of protection. Backup protection may be provided locally, remotely, or both locally and remotely.

3.3. Local Backup

The local backup method provides backup protection by adding redundant Protection Systems locally at a substation such that any Protection System component failure is backed up by another device at the substation. For local backup to provide redundancy, the local backup Protection System must sense every fault and consist of separate Protection System components, as discussed in the NERC SPCS Technical Reference Document "Protection System Reliability." To back up the failure of a circuit breaker to interrupt current, breaker failure circuitry is commonly used to initiate a trip signal to all circuit breakers that are adjacent to the failed breaker. On some bus arrangements, this may require transfer tripping to one or more remote stations.

[6] IEEE PSRC, Working Group I19, Redundancy Considerations for Protective Relaying Systems, 2010.

3.4. Remote Backup

The remote backup method provides backup by using the Protection Systems at a remote substation to initiate clearing of faults on equipment terminated at the local substation. Figure 3.4.1 depicts use of the terms "local" and "remote" in the context of this discussion.

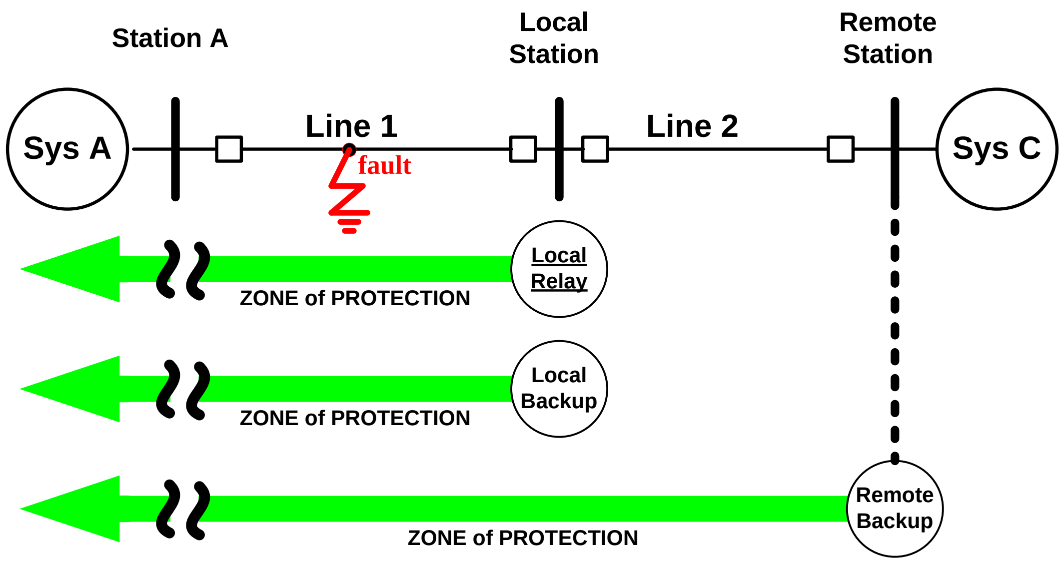


Figure 3.4.1 — Definition of Local and Remote Backup As Applied to Transmission Lines

Remote backup may be used to provide protection for single or multiple Protection System failures or failures of circuit breakers to interrupt current at the local substation. When remote backup is used to provide backup protection for a single Protection System failure or a failure of a circuit breaker to interrupt current, the relays at the remote station are set sensitive enough that they can detect all faults that should be cleared from the adjacent (local) substation for which backup protection is being provided. Remote backup may provide an additional benefit of protecting for multiple Protection System failures, but the relays at the remote station may not be set sensitive enough that they can detect all faults that should be cleared from the local substation.

When remote backup can be set to meet system performance requirements it can provide complete Protection System redundancy since it shares no common components with the local relay system. The remote backup protection is intentionally set with time delay to allow the local relaying enough time to isolate the faulted Elements from the power system prior to the remote terminals operating. The remote backup protection covers the failure of a Protection System and/or the failure of a circuit breaker to interrupt current.

4. Advantages and Disadvantages of Local and Remote Backup Protection

4.1. Advantages of Local Backup Protection Systems

- **System disruption** - For the failure of the local Protection System or the circuit breaker, local backup protection usually isolates a smaller portion of the transmission grid as compared to remote backup protection.
- **Relay loadability** – Local backup protection generally has no effect on relay loadability because it is set similarly to the primary system. Local backup does not require as sensitive a setting as remote backup and therefore is less susceptible to loadability concerns.
- **Tripping on Stable System Swings** – Local backup protection is less susceptible to operation for stable power swings for the same reasons it is less susceptible to loadability concerns.
- **Speed of operation** – Generally, local backup Protection Systems can be set to operate more quickly than remote backup Protection Systems.

4.2. Disadvantage of Local Backup Protection Systems

- **Multiple Local Protection System Failures** – Providing redundant Protection Systems does not eliminate the possibility of all common mode failures. A well designed fully redundant local Protection System can fall short when multiple local Protection System failures occur.

4.3. Advantages of Remote Backup Protection Systems

- **Common Mode Failures** – Use of remote backup systems, because of their physical separation, minimizes the probability of delayed clearing or failure to clear a fault due to a common mode failure.

- **Multiple Protection System Failures** – Remote backup can, in some cases, provide a safety net to limit the extent of an outage due to multiple local Protection System failures. This is especially significant for low-probability scenarios that exceed design criteria.
- **Reduced Reliance on Telecommunication** – Remote backup protection generally does not rely on telecommunication between substations.

4.4. Disadvantages of Remote Backup Protection Systems

- **Slow Clearing** – Remote backup generally requires longer fault clearing times than local backup to allow the local Protection System to operate first.
- **Wider-Area Outage for Single Failures** – For a single Protection System failure, remote backup generally requires that additional Elements be removed from the power system to clear the fault versus local backup. Depending on the scenario, this can have the added impact of de-energizing the local substation and interrupting all tapped load on the lines that are connected to the substation where the relay or breaker fails to operate.
- **Relay loadability** – The desired setting of remote backup is more likely to conflict with the relay loadability requirements than local backup.
- **Tripping on Stable System Swings** – Remote backup is more susceptible to tripping during stable system swings because this application typically requires relay settings with longer reach or greater sensitivity than local backup.
- **Difficult to Detect Remote Faults** – It is more difficult and more complicated to set remote backup protection to detect all faults in the protected zone for all possible system configurations prior to a fault.
- **Difficult to Study** – It is generally more difficult to study power system and Protection System performance for a remote backup actuation. This is because more power system Elements may trip. Tripping may be sequential and reclosing may occur at different locations at different times. For example, tapped loads may be automatically reconfigured and prolonged voltage dips that may occur due to the slow clearing may cause tripping due to control system actuations at generating plants or loads. It is very difficult to predict the behavior of all control schemes that may be affected by such a voltage dip, thus it is very difficult to exactly predict the outcome of a remote backup clearing scenario.

5. System Performance Requirements

The Bulk Electric System must meet the performance requirements specified in the Transmission Planning (TPL) standards when a single Protection System failure or a failure of a circuit breaker to interrupt current occurs. When a single Protection System failure or failure of a circuit breaker to interrupt current prevents meeting the system performance requirements specified in the TPL standards, either the Protection System or the power system design must be modified.

When time delayed clearing of faults is sufficient to meet reliability performance requirements, owners have the option to deploy either two local systems or one local system and a remote backup system to meet reliability levels. In either case, the Protection Systems must operate and clear faults within the required clearance time to satisfy the system performance requirements in the TPL standards.

Backup protection may also function as a safety net to provide protection for some conditions that are beyond the system performance requirements specified in the TPL standards. When used as a safety net, backup protection may be designed to protect against a specific multiple Protection System failure or failures of circuit breakers to interrupt current. Backup protection may also be designed to limit the extent of disturbances due to unanticipated multiple Protection System failures or failures of circuit breakers to interrupt current. When backup is applied as a safety net it must meet the requirements of current NERC standards related to relay loadability, Protection System coordination, and system performance requirements during a single Protection System failure or failure of a circuit breaker to interrupt current. Future standards related to Protection System performance during stable system swings may also affect the use of backup protection and provide further guidance on assessing relay response during stable swings. When remote backup is applied as a safety net it may be appropriate to place a greater emphasis on security over dependability.

5.1. Function of Local Backup

The main function of local backup is to address a single local Protection System failure or failure of a circuit breaker to interrupt current. The redundancy provided by local backup inherently addresses single Protection System failures while minimizing the impact to the system. Local backup may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme.

Breaker failure is a form of local backup that must be studied per NERC Planning Standards. The effects of a breaker failure operation must be studied to determine that system performance requirements are met. It is common throughout the industry to apply local breaker failure protection for transmission level circuit breakers.

5.2. Function of Remote Backup:

Remote backup can play a role in addressing single or multiple Protection System failures or failures of circuit breakers to interrupt current.

For addressing a single Protection System failure or failure of a circuit breaker to interrupt current, local backup is generally preferred to remote backup for many of the reasons stated above. However, certain configurations lend themselves to the use of remote backup while minimizing the disadvantages of using remote backup. Examples are discussed later in this document.

Multiple Protection System failures may not be anticipated or studied. The degree to which protection designs can detect faults under the condition of multiple Protection System failures varies based on a company's design practices, system topology, and a number of other factors.

Remote backup protection can provide a safety net minimizing the impact of unanticipated conditions caused by multiple Protection System failures to a greater degree than that afforded by local backup protection only.

Multiple failures due to more common combinations of single Protection System failures and/or failures of circuit breakers to interrupt current occurred in a number of the examples of post-2003 events discussed below.

6. Post-2003 Events Involving Backup Protection

6.1. 2008 Florida Event

6.1.1. Description of the 2008 Florida Event

On February 26, 2008, a system disturbance occurred within the FRCC Region that was initiated by delayed clearing of a three-phase fault on a 138 kV switch at a substation in Miami, Florida. According to the report "FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26th, 2008 at 1:09 pm" it resulted in the loss of 22 transmission lines, approximately 4300 MW of generation and approximately 3650 MW of customer load. The local primary protection and local backup breaker failure protection associated with a 138 kV switch had been manually disabled during troubleshooting. The fault had to be isolated by remote clearing because the local relay protection had been manually disabled.

6.1.2. Backup Protection and the Florida Event:

The report states "The 230 kV/138 kV autotransformers at Flagami do not utilize phase overcurrent or impedance backup protection. Although there are no current industry requirements for this type of protection, the autotransformers offer a position to install additional local relaying that could be used to isolate the 230 kV system from faults on the 138 kV system." Furthermore the investigation recommends "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection of autotransformers." The lack of autotransformer backup protection that contributed to this event was addressed by the installation of new protection equipment after this event.

6.2. 2004 West Wing Substation Event

6.2.1. Description of the 2004 West Wing Substation Event:

Another significant event where fault clearing times and the extent of outages could have been improved by the use of local backup or planned remote backup protection was the West Wing event on June 14th, 2004. In this event, a 230 kV line faulted to ground. The relay system for the faulted 230 kV line was designed with a single auxiliary tripping relay. This relay was used for tripping of the 230 kV line breakers and breaker failure initiation. The single auxiliary relay failed. Remote backup clearing with clearing times of 20 to 40 seconds was required to clear the fault. The remote clearing required in this case resulted in the loss of ten 500 kV lines, six 230 kV lines, and over 4500 MW of generation (including three nuclear units) per the initial WECC communication on the event. A couple of weeks after the event, several of the single-phase 500/230 kV autotransformers involved in the event failed catastrophically.

6.2.2. Backup Protection and the West Wing Event:

The first recommendation from the Arizona Public Service (APS) report "June 14, 2004 230 kV Fault Event and Restoration" was to add backup protection to the 500/230 kV autotransformers involved in the event. The report states that had backup protection been installed on the 500/230 kV autotransformers that the fault would have been cleared significantly faster and damage would have been prevented, and this remote backup "would have prevented the disturbance from being cleared within the 500 kV system".

Additionally, if the local protection scheme at West Wing included fully redundant systems with redundant auxiliary tripping relays, this event could have been mitigated.

Both the lack of remote backup protection and the lack of redundant local protection that contributed to this event were addressed by the installation of new protection equipment after this event.

6.3. 2007 Broad River Event

6.3.1. Description of the 2007 Broad River Event:

Another event where remote backup protection played a key role was the August 25, 2007 Broad River Energy Center Event. In this event, a 230 kV generator step-up transformer bushing failed and faulted to ground. The relay system for the faulted 230 kV transformer was designed with a single auxiliary tripping relay. The single auxiliary relay failed. Remote backup protection cleared the fault in about 0.5 seconds. The remote clearing in this case resulted in the loss of four 230 kV transmission lines and three Broad River Energy Center Units. In addition one 230 kV transmission line tripped due to a failed relay, two generating units tripped due to incorrectly coordinated backup protection settings, and two generating units tripped due to low station auxiliary bus voltage during the fault.

6.3.2. Backup Protection and the Broad River Event:

Recommendations from the NERC investigation report for this event included installing redundant relaying for the generator step-up transformer that sustained the fault. This recommendation has been implemented.

The overall effects of this event to the power system were minor compared to the Florida or West Wing events. However, this event does illustrate that when remote backup is applied to meet system performance requirements during single Protection System failures, the highest degree of coordination of Protection Systems and knowledge of system reactions to sustained low transmission level voltage is needed.

6.4. 2006 Upper New York State Event

6.4.1. Description of the 2006 Upper New York State Event:

The last event is a near miss event that occurred in New York State on March, 29, 2006 in the switchyard for a hydro plant. In this event, a ground fault occurred on the 13.8 kV side of a 115/13.8/13.8 kV transformer due to raccoon contact. The fault quickly evolved into a 3-phase to ground fault on the 115 kV side of the transformer. One of the 115 kV circuit breakers required to clear the 13.8 kV and 115 kV faults failed. Breaker failure was initiated to clear the fault via the surrounding circuit breakers; however one of these breakers failed to clear for about 5 seconds resulting in a double breaker failure for 5 seconds. During this time, all 14 in-service hydro units at the connected plant tripped on backup phase distance relays. The switchyard at this location also included a number of 230/115 kV autotransformers and 230 kV lines. The 230/115 kV autotransformer relay schemes in this area were not designed with phase backup protection that could detect this 115 kV fault. The delayed clearing in this event resulted in the loss of the 14 units at the hydro plant, numerous smaller hydro-generating facilities throughout northern New York, and one unit in Ontario, totaling 1200 MW, as well as various equipment in the connected switchyard.

6.4.2. Backup Protection and the Upper New York State Event:

Recommendations from the New York Power Authority (NYPA) investigation report for this event included considering whether to apply overcurrent backup protection on autotransformers. A decision whether to add backup overcurrent protection has not been made at this time.

The overall effects of this event to the power system were minor compared to the Florida or West Wing events. However, this event is a good illustration of the type of unanticipated failure event where remote backup protection can provide a safety net that may limit the extent of an outage.

7. Examples

The following sections provide a number of examples of backup protection applied to transmission lines and transformers. It is important to note that these examples were selected to illustrate concepts discussed in the paper and are not intended to be prescriptive or to suggest a preferred method of transformer protection, nor are they inclusive of all possible methods for providing backup protection. The protection system design (e.g., CT and PT primary connections) and settings derived in these examples are only for illustrative purposes.

7.1. Remote Backup Protection on Transmission Lines

Protection Systems applied to transmission lines commonly include elements which provide remote backup protection. The most common type of remote backup protection for phase faults on transmission lines is phase distance relaying with fixed time delay. The most common methods to provide remote backup for ground faults are by using ground distance relays with fixed time delay, ground time overcurrent relays with inverse time-current curves, or a combination of both. Phase faults generally affect the system to a higher degree than ground faults and phase relays are more susceptible to tripping than ground relays for severe system conditions.

The following series of examples focus on phase faults and illustrate some of the complexities of using remote backup protection as outlined above. Examples 1, 2, and 3 illustrate the complexity of applying remote backup protection to meet NERC system performance requirements during a single Protection System failure. In these examples the line terminals do not have local backup protection. Example 1A is used to illustrate application of remote backup protection for breaker failure protection. In this example the line terminals have local backup protection.

7.1.1. Example 1:

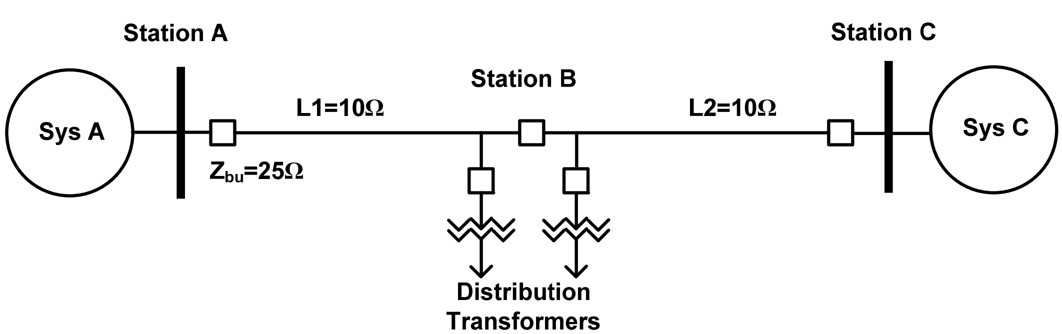


Figure 7.1.1 — Simple Three-Station, Two-Line System Used in Example 1

The simple system of two lines in Figure 7.1.1 shows the configuration under consideration in this example. In this case, the backup zone at the Station A line terminal can be set to cover phase and ground faults on the transmission line between Stations B and C and provide remote backup for any single transmission line Protection System related component failure. For this configuration, source impedances behind Stations A and C are not important.

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L2 is Z_{bu} = 1.25 (L1 + L2) = 25 Ω

7.1.1.1. Complexities

If a time delay of 0.7 to 1.0 seconds is assumed, remote backup clearing would be slower than a local breaker failure scheme with transfer trip from Station B to Station A. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. In many cases similar to this example the remote backup can be set within the loadability requirements of PRC-023, will not reach through the distribution transformers, and will provide adequate backup protection for Protection System failures at Station B.

7.1.2. Example 1A

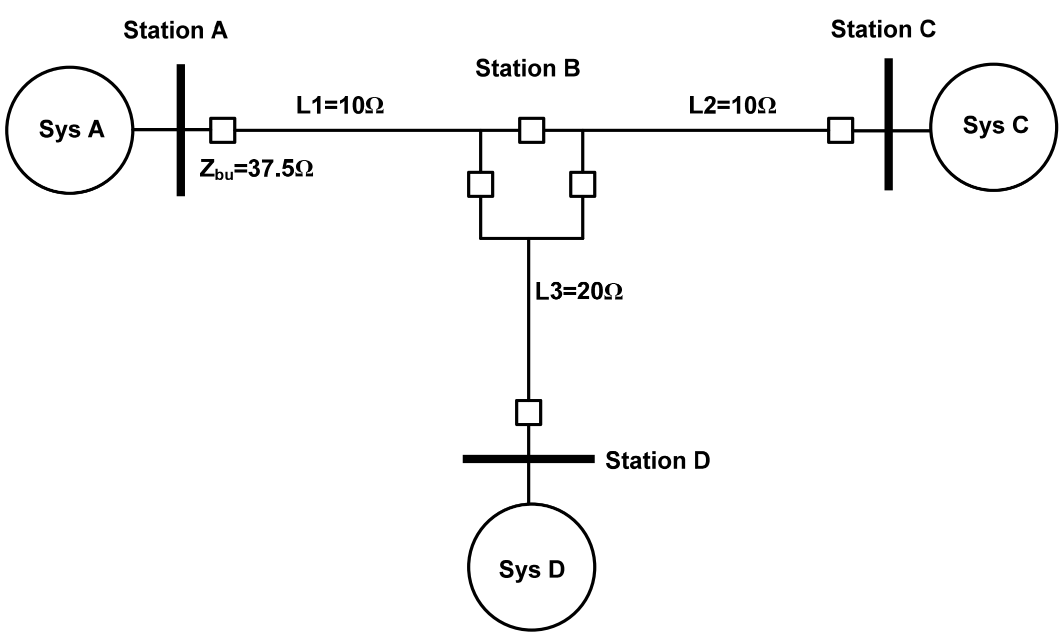


Figure 7.1.2 — Simple Four-Station, Three-Line System Used in Example 1A

The simple system of three lines in Figure 7.1.2 shows the configuration under consideration in this example. In this case, all of the line terminals have local backup protection for line faults as defined in section 3. Thus, a backup zone at the Station A line terminal may be designed to provide protection to address a couple of different situations:

1) The breaker failure protection scheme for the breakers at Station B is designed with local breaker failure but without breaker failure transfer trip communications capability from Station B to Station A. Due to the lack of transfer trip communications, the backup zone at Station A is designed to provide backup protection for faults on lines BC or BD with a breaker failure at Station B. Because the Station B breakers have local breaker failure protection, the Station A relay can be set to cover phase and ground faults on the transmission line between Stations B and C or B and D without considering apparent impedance (i.e., the local breaker failure operation at station B will open the other two breakers and remove the infeed). The owner of this scheme has decided to use backup instead of installing a transfer trip channel. This backup setting will also provide some protection for multiple Protection System failures of line BC or BD relaying. For this configuration and application, source impedances behind Stations A, C and D are not important.

2) The breaker failure protection scheme for the breakers at Station B is designed with local breaker failure and breaker failure transfer trip communications capability from Station B to Station A. The backup zone at Station A is designed to provide backup protection for faults on lines BC or BD with a breaker failure and a loss of transfer trip communications at Station B. Similar to the first situation, because the Station B breakers have local breaker failure protection, the Station A relay can be set to cover phase and ground faults on the transmission line between Stations B and C or B and D without considering apparent impedance for this application. This application protects for a situation that is beyond a single Protection System failure or failure of a circuit breaker to interrupt current and is thus not required to meet system performance requirements. The owner of this scheme has decided to apply backup as a safety net and may have decided to apply this type of backup based on past experiences or events. This backup setting will also provide some protection for multiple Protection System failures of line BC or BD relaying. For this configuration and application, source impedances behind Stations A, C and D are not important.

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L3 is Z_{bu} = 1.25 (L1 + L3) = 37.5 Ω.

7.1.2.1. Complexities

If a time delay of 0.7 to 1.0 seconds is assumed, remote backup clearing would be slower than a local breaker failure scheme with transfer trip from Station B to Station A. When the system is designed without transfer trip capability, a transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. In many cases similar to this example the remote backup can be set within the loadability requirements of PRC-023, will not reach through the distribution transformers, and will provide adequate backup protection for breaker failures at Station B and some line Protection System failures at Station B. Figure 7.1.5 illustrates the increased backup protection reach in this example compared to Example 1.

7.1.3. Example 2

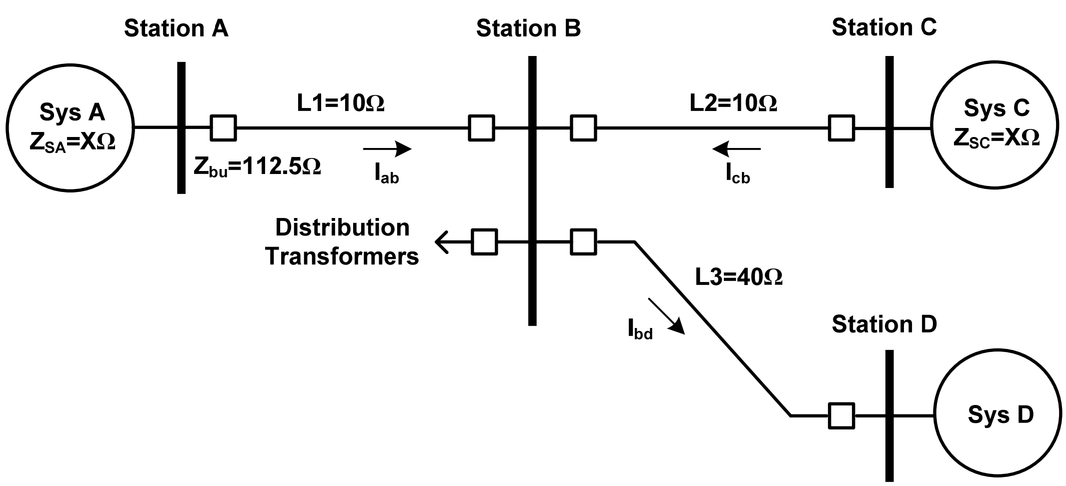


Figure 7.1.3 — Four-Station, Three-Line System Used in Example 2

Example 2 is complicated compared to Example 1A by the presence of a longer line between Stations B and D and the distribution transformers at bus B. For this configuration, source impedances behind Stations A and C are assumed to be equal. The source impedance behind Station D is not important in this simple system. In this case, a fault on L3 near Station D would be difficult to detect from Station A without overreaching for faults beyond Station C or seeing through the distribution transformers.

The apparent impedance seen by the relay at Station A is:

$$Z_{bu} = V_a/I_{ab} = ((I_{ab} \text{ x } L1) + (I_{bd} \text{ x } L3))/I_{ab} = L1 + (I_{bd}/I_{ab}) \text{ x } L3$$

Given the symmetry of the example system, $I_{ab} = I_{cb}$, and thus I_{bd} = 2Iab

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L3 is $Z_{bu} = 1.25\ (L1 + 2L3) = 112.5\ \Omega$.

If the source impedance of System A could be higher for certain system conditions, the setting would need to be increased accordingly.

7.1.3.1. Complexities

In this case, such a large setting at Station A may detect distribution level faults at Station B. A time delay of 0.7 to 1.0 seconds would be required to coordinate with remote relaying at Stations B and C given that the Station A backup zone will likely detect all faults on L2 and may look far past Station C, especially when L3 is out of service. The longer time to clear may also cause power quality issues for the loads at Stations A, B, or C that in the worst case may result in local loss of load. In many cases similar to this example it may not be possible to set the remote backup within the loadability requirements of PRC-023 without the use of some form of load encroachment. The larger setting might also be more susceptible to tripping on stable system swings. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. Figure 7.1.5 illustrates the increased backup protection reach in this example compared to Examples 1 and 1A.

7.1.4. Example 3

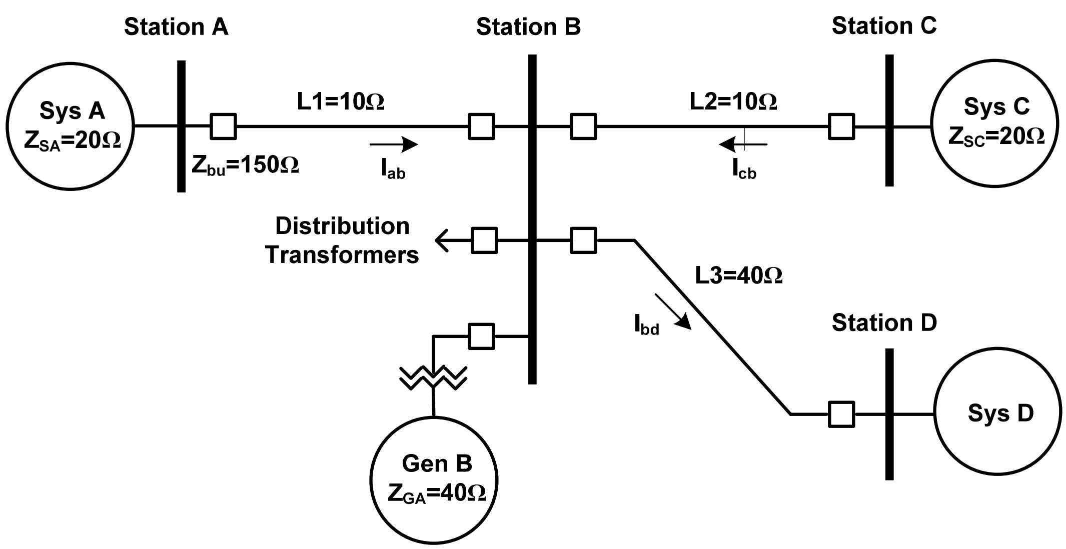


Figure 7.1.4 — Four-Station, Three-Line System Used in Example 3

Example 3 is further complicated compared to Example 2 by the presence of a generator at Station B. For this configuration, source impedances behind Stations A and C are assumed to be equal at 20 Ω with a reasonable system contingency source outage behind Station A. The impedance of the generator at Station B (including the generator step-up transformer) is assumed to be equal to 40 Ω. The source impedance behind Station D is not important for this example and can be ignored. In this case, a fault on L3 near Station D would be more difficult to cover.

The apparent impedance seen by the relay at Station A must be calculated:

> For the given fault, System A + L1 is in parallel with System C + L2, and the combination of these two systems is in parallel with Generator B, with all three systems in series with L3,
>
> Or
>
> The equivalent impedance of these systems is 30 Ω is in parallel with 30 Ω, in parallel with 40 Ω, + 40 Ω = 50.9 Ω

For fault near Station D on a 138 kV system, the total fault contribution from System A, System C, and Generator B is 1571 A.

The fault current contribution at Station A is 571 A and the line-to-ground voltage is 68.550 kV.

The apparent impedance at Station A for the L1 line relay is ~120 Ω

For this example, using a 25 percent margin, the backup relay reach at Station A necessary to detect all faults on line L3 is Z_{bu} = 1.25 (120) = 150 Ω

Additionally, the voltage on the Station B 138 kV bus is ~ 0.82 per unit.

7.1.4.1. Complexities

In this case, such a large setting at Station A may detect distribution level faults at Station B. A time delay of 0.7 to 1.0 seconds may be required to coordinate with remote relaying at Stations B and C given that the Station A backup zone will likely detect all faults on L2 and may look far past Station C, especially when L3 is out of service and/or Generator B is out of service. Thus, remote backup clearing would be much slower than local backup clearing. The longer time to clear may cause power quality issues for the loads at Stations A, B, or C that in the worst case may result in local loss of load. The longer time to clear and resulting lower voltage dip at the Station B bus may also cause an issue for the auxiliary equipment at Generating Station A that could result in a loss of generation. In many cases similar to this example it may not be possible to set the remote backup within the loadability requirements of PRC-023 without the use of some form of load encroachment. The larger setting might also be more susceptible to tripping on stable system swings. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements.

In general, a system such as shown in Figure 7.1.4 requires much greater care and study to ensure adequate system performance prior to implementation than a system that uses local backup to cover for faults on L3. Additionally, much greater care is required as the system changes over time to ensure that the remote backup system for Example 3 still provides adequate fault coverage while meeting system performance requirements. Figure 7.1.5 illustrates the increased backup protection reach in this example compared to Examples 1, 1A, and 2. It must be noted that the line lengths in the various examples were purposely picked to illustrate the effects that apparent impedance can have on remote backup settings. The extent to which relay reach must be increased for actual configurations may be more or less than shown in these examples.

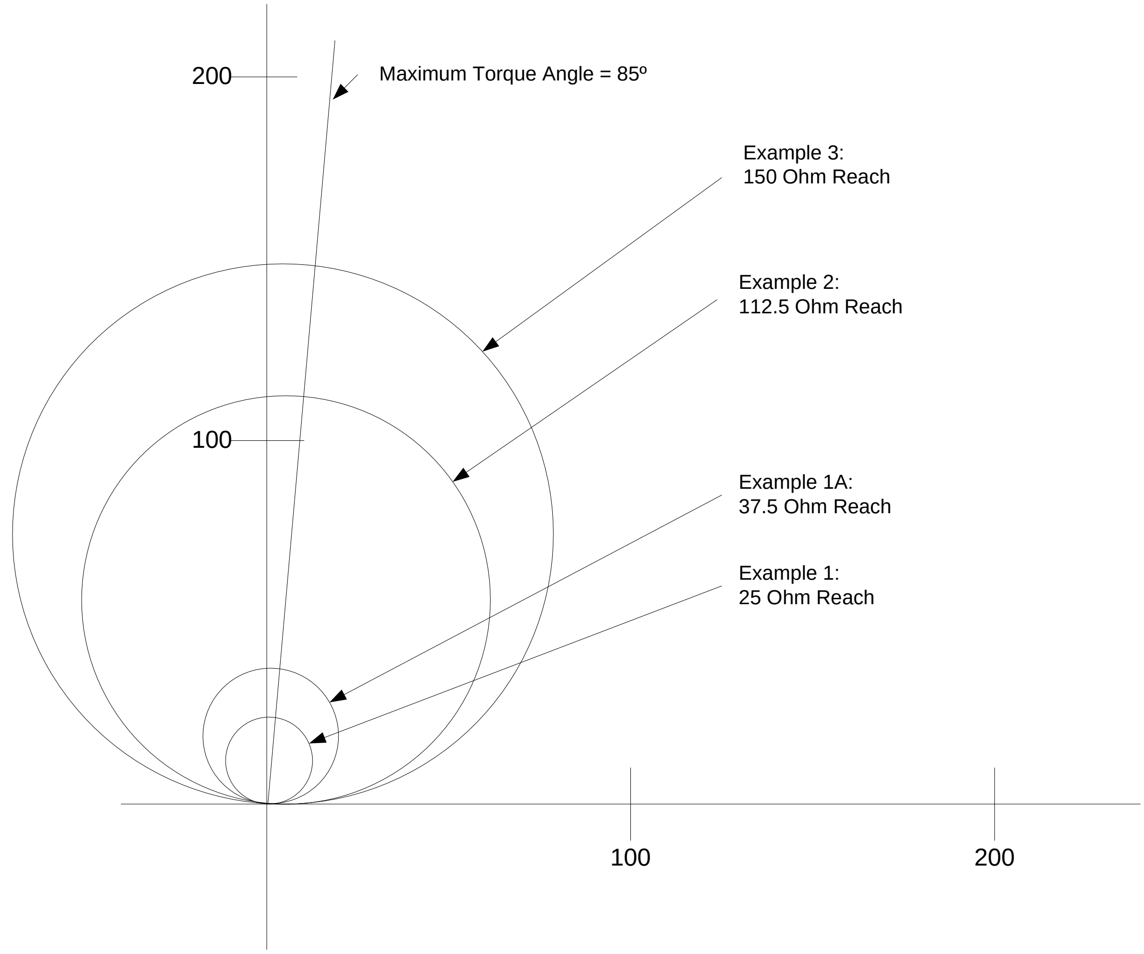


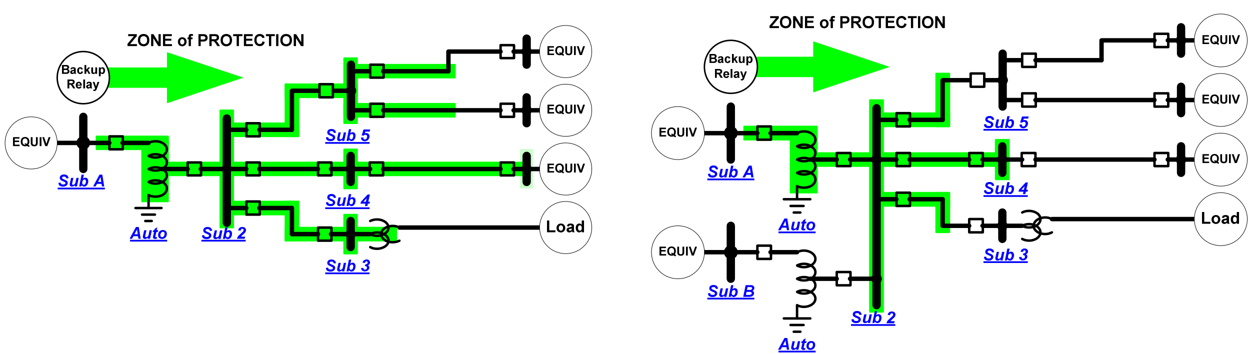
Figure 7.1.5 — Comparison of Backup Protection System Reach for Examples 1, 1A, 2, and 3

7.2. Backup Protection on Autotransformers

Applying phase backup protection on autotransformers is not as common as applying remote backup on transmission line terminals. Backup protection on transformers can be applied as backup for faults on both the high side and low side voltage levels and is commonly applied to protect transformers for uncleared faults.

The system events involving multiple voltage levels described in Section 6 were all related to faults on equipment on lower voltage systems (115 kV or 230 kV). These events support the general observation that the level of redundancy of protection on higher voltage level circuits is usually greater than that on the lower voltage circuits connected to autotransformers. Some lower voltage lines may not have local redundancy at all and the use of backup protection on the transformers may provide additional protection for uncleared faults.

Autotransformer backup may be designed to clear faults due to single relay failures or as a safety net. Figure 7.2.1 provides examples of the safety net protection coverage that may be achieved for two possible system configurations. In the second configuration, the reach of the backup protection will be reduced by roughly one-half versus the first configuration due solely to the paralleled equivalent contributions of the two transformers. When autotransformer backup protection is counted on to clear faults due to single relay failures, it is subject to meeting system performance requirements and subject to many of the same limitations as remote backup on transmission lines. When lower voltage systems are fully redundant, autotransformer backup can provide a safety net to limit damage to the low voltage system and isolate the low voltage system from the high voltage system for slow clearing faults due to multiple Protection System failures or failures of circuit breakers to interrupt current.



Transformer Backup Reach
One Auto Transformer

Transformer Backup Reach
Two Auto Transformers

Figure 7.2.1 — Safety Net Backup Protection Reach

Since the cited system events involving multiple voltage levels were related to faults on the lower voltage systems, the discussion on autotransformer backup will focus on backup applied to detect faults on the low voltage side of the autotransformer. The discussion will also be geared toward phase faults since phase faults generally negatively affect the system to a higher degree than ground faults and most transformer Protection Systems include ground backup protection. Additional reasons to focus on phase faults are that slow clearing ground faults can migrate into phase faults, and phase relays are more susceptible to tripping due to loadability issues than ground relays for severe system loading conditions.

Various methods may be utilized to protect and clear an autotransformer for phase faults external to an autotransformer. Three common types of phase backup protection for autotransformers to be discussed in this paper with examples are: phase time overcurrent relays; phase time overcurrent relays torque controlled by phase distance relays and phase instantaneous relays; and phase distance and phase instantaneous relays with fixed time delays. A fourth type of backup that can be applied on a transformer low side to provide backup protection for low side bus or close-in fault protection failure that has little complexity is a limited reach distance function. This application does not have relay loadability issues that may be associated with other methods. Additional discussion on transformer backup protection is provided in the IEEE Guide for Protective Relay Applications to Power Transformers (IEEE C37.91).

A very inverse time overcurrent curve will be used in the examples in this paper. Other types of curves have different advantages and disadvantages which are outside the scope of this paper and require similar considerations.

Example Autotransformer Data:

- 345(wye)/34(delta)/138(wye) kV with no delta connected load
- 300 MVA maximum nameplate for the 345/138 winding
- 1250 A nameplate at 138 kV and 500 A nameplate at 345 kV
- Maximum 138 kV 3-phase fault = 20,000 A ($Z_{TR} \sim 4\ \Omega$ @ 138 kV)
- This transformer has been determined to be critical by the Planning Coordinator and is thus subject to PRC-023 limitations

7.2.1. Relay Settings Based on a Simple System

A phase protective relay could be applied on either the high or the low side of the autotransformer. For the examples that follow, the current elements of all of the phase protective relays are connected to current transformers on the high side of the transformer. Thus, these relays also may provide backup protection for faults on the transformer high side and tertiary windings. In many cases, 3-phase potential devices are only available on the low side of the transformer so the phase distance relays are applied on the 138 kV side of the transformer. This also allows for a better reach of the phase distance relay into the 138 kV system as this connection does not result in the Protection System detecting the voltage drop through the transformer for 138 kV faults.

A desirable goal is to create a generic method for setting the phase protection relays that provides adequate backup protection, coordinates with other system relays, provides adequate overload protection for uncleared through-faults, will not trip on transformer inrush, and meets the loadability limitations of PRC-023-1. It may not be possible to meet all of these goals for all configurations of some systems. Two examples (a simple system and a more complex system) illustrate some of these limitations.

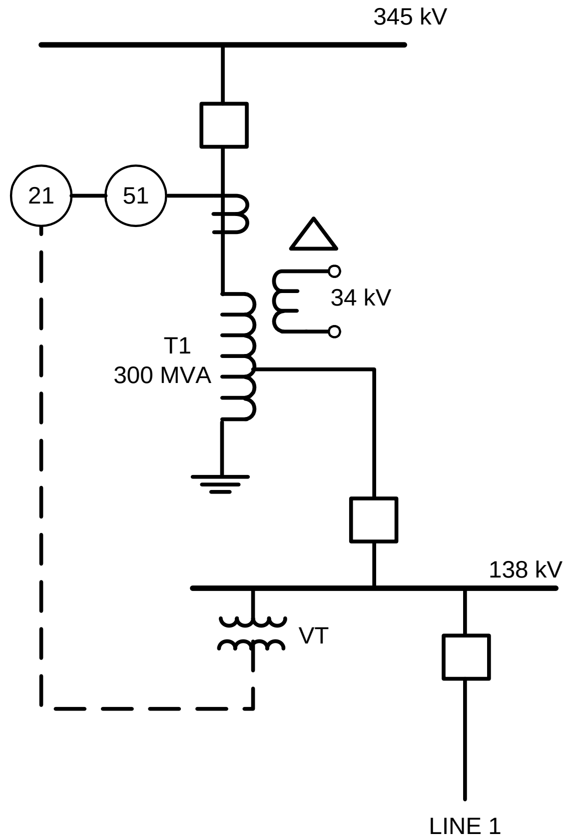


Figure 7.2.2 — Simple System One-Line Used in Transformer Protection Example

7.2.1.1. Example 4: Phase Time Overcurrent Relay Setting

In this example PRC-023 limitations for phase responsive transformer relays will dictate the minimum pickup setting of the relay. These limitations are:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooling ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

Assuming there are no operator established emergency transformer ratings for this transformer, the minimum pickup for this relay is limited to 150% of 300 MVA. On the 345 kV side this translates to ~ 750 A. Adding a minimum of additional margin and creating a setting that could likely be used for electromechanical relays with limited tap selections, the minimum pickup will be set to 800 A (about 2000 A at 138 kV).

To coordinate with local 138 kV breaker failure for close-in faults (typical 10 cycle breaker failure relay time is assumed), the minimum time to trip must be at least 0.4 second. This tripping speed also ensures that this relay trips faster than remote backup protection on the high voltage system (1 second is assumed) that may also detect low voltage system faults (especially close-in low voltage system faults). Thus, a time lever of 3 is chosen. Using the very inverse curve, the time for the relay to initiate a trip will then be about 0.4 second for a 20,000 A 138 kV fault, 0.77 second for a 10,000 A 138 kV fault and 1.74 seconds for a 6,000 A 138 kV fault. Coordination must be verified between these fault clearing times and the 138 kV line L1 protection (see Figure 7.2.2). The clearing times in this example were selected because they will coordinate with typical transmission line protection settings, will be secure during transformer inrush conditions, and are faster than required to coordinate with the transformer through-fault damage curve shown in IEEE Standard C37.91-2000.

7.2.1.2. Example 5: Torque Controlled Phase Time Overcurrent Settings

For this relay, a mho phase distance element and a phase instantaneous overcurrent element both torque control a phase time overcurrent. The phase time overcurrent element will not pickup and start timing until the mho phase distance element or the phase instantaneous overcurrent element picks up first. This allows a more sensitive phase time overcurrent setting than a pure phase time overcurrent relay since the phase time overcurrent relay is not subject to the loadability limitation. The phase instantaneous element is needed in addition to the phase distance element to cover for 138 kV bus faults and other close-in faults where the phase distance element may lose memory voltage and drop out prior to fault clearing given that the phase distance element is connected to the 138 kV potential device.

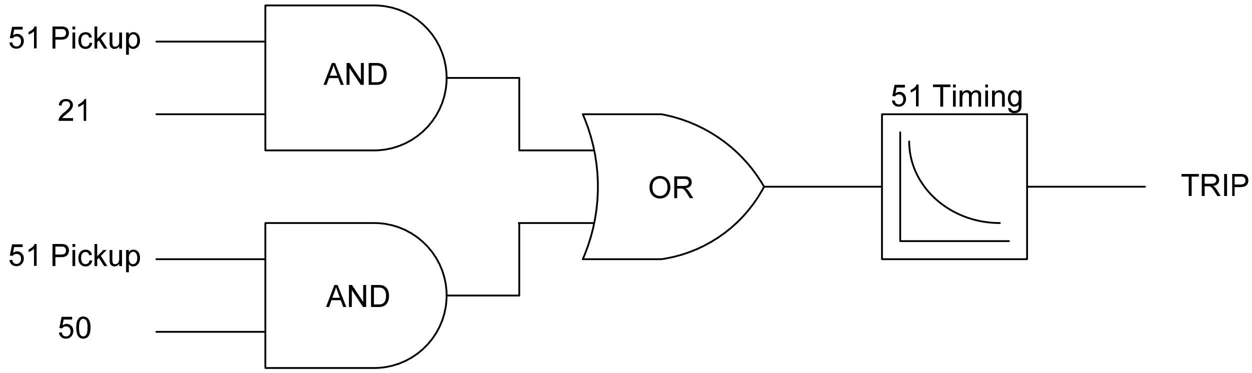


Figure 7.2.1.3 — Logic Diagram for Application of Phase Time Overcurrent Elements Torque Controlled by Phase Distance and Instantaneous Phase Overcurrent Elements

7.2.1.2.1. Phase Distance Element Setting

Assuming there are no operator established emergency transformer ratings for this transformer, the same PRC-023 limitation (150% of maximum nameplate rating) will limit the reach of the phase distance relay. Using the NERC criteria and assuming the relay uses a mho characteristic,

Max Allowable Setting = $Z_{relay@30} = (0.85*V_{relay})/(1.732*I_{Nameplate}*1.5)$

where V_{relay} = phase-to-phase line voltage at the relay location

and $I_{Nameplate}$ = 1250 A

To make the loadability of this setting equivalent to the time overcurrent for comparison purposes, we will use 800 A at 345 kV (2000 A at 138 kV) instead of $I_{Nameplate}$*1.5 (750 A at 345k V or 1875 A at 138 kV) to determine the loadability limitation. This limits $Z_{relay@30}$ to about 34 Ω at 138 kV. Since this relay is subject to PRC-023, this relay will be set with a 90 degree torque angle to maximize loadability. Thus $Z_{relay@90}$ is set to 68 Ω ($Z_{relay@90} = Z_{relay@30}/\cos(90-30)$). A typical 138 kV line impedance angle is 75 degrees. The reach at the 75 degree line angle is 68*cos(15) = 66 Ω.

7.2.1.2.2. Phase Instantaneous Overcurrent Element Setting

If high side potentials are available and used for the phase distance element, this element may not be required. The use of high side potentials to feed a distance relay does, however, limit the reach of the relay into the lower voltage system. The examples in this document are based on use of low side potential devices, so this element is included in this example as a method for assuring reliable operation for close-in low side faults when the phase distance relays do not have sufficient memory polarization for the duration of a zero voltage fault.

The instantaneous phase element setting is required for close-in three-phase faults where the phase distance relay may not operate because of very low voltage. Thus, sensitivity is not a great concern. Set this element to 225% of transformer nameplate to provide ample margin above emergency loading or roughly 1200 A at 345 kV (3000 A at 138 kV).

7.2.1.2.3. Phase Time Overcurrent Setting:

The phase time overcurrent minimum pickup is not subject to loadability limitations because the phase distance and instantaneous phase overcurrent relays that provides the torque control meets the loadability requirement; however, it may be desirable to provide additional security. For this example, the relay is set at 500 A at 345 kV (corresponding to the transformer nameplate rating) as a balance between security and sensitivity.

To coordinate with local 138 kV breaker failure for close-in faults, the minimum time to trip must be at least 0.4 second. This tripping speed also ensures that this relay trips faster than remote backup protection on the high voltage system (1 second is assumed) that may also detect low voltage system faults (especially close-in low voltage system faults). Thus, a time lever of 3.5 is chosen. Using the very inverse curve, the time to trip for selected 138 kV faults will then be about 0.39 second for a 20,000 A fault, 0.55 second for a 10,000 A fault, and 0.96 second for a 6,000 A fault. Coordination must be verified between these fault clearing times and the 138 kV line L1 protection (see Figure 7.2.2). The clearing times in this example were selected because they will coordinate with typical transmission line protection settings, will be secure during transformer inrush conditions, and are faster than required to coordinate with the transformer through-fault damage curve shown in IEEE Standard C37.91-2000.

7.2.1.3. Example 6: Phase Distance and Instantaneous Phase Overcurrent with Fixed Timers Settings

For this relay, a mho phase distance element tripping through a fixed timer is used. When the potential is provided from the low side of the transformer, the phase distance element is supplemented by an instantaneous phase overcurrent relay that also trips through the fixed timer.

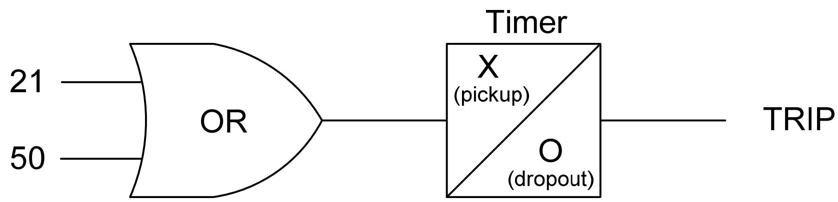


Figure 7.2.1.3 — Logic Diagram for Application of Phase Distance and Instantaneous Phase Overcurrent Elemets with Fixed Timers

7.2.1.3.1. Phase Distance Element Setting

Assuming there are no operator established emergency transformer ratings for this transformer, the same PRC-023 limitation (150% of maximum nameplate rating) will limit the reach of the phase distance relay. Using the NERC criteria and assuming the relay uses a mho characteristic,

Max Allowable Setting = $Z_{relay@30} = (0.85*V_{relay})/(1.732*I_{Nameplate}*1.5)$

where V_{relay} = Phase-to-phase line voltage at the relay location

and $I_{Nameplate}$ = 1250 A

To make the loadability of this setting equivalent to the unsupervised phase time overcurrent for comparison purposes, we will use 2000 A instead of $I_{Nameplate}*1.5$ (1875 A) to determine the loadability limitation. This limits $Z_{relay@30}$ to about 34 Ω. This relay will be set with a 90 degree torque angle to maximize reach while meeting the loadability limitation. Thus $Z_{relay@90}$ is set to 68 Ω ($Z_{relay@90} = Z_{relay@30}/\cos(90\text{-}30)$). A typical 138 kV line impedance angle is 75 degrees. This reach at the 75 degree line angle is 68*cos(15) = 66 Ω.

7.2.1.3.2. Instantaneous Phase Overcurrent Element Setting

If high side potentials are available, this element may not be required. The use of high side potentials to supply a distance relay does, however, limit the reach of the relay into the lower voltage system. The examples in this document are based on use of low side potential devices, so this element is included in this example.

The instantaneous phase element setting is required only for close-in three-phase faults where the phase distance relay may not operate because of very low voltage. Since for this example the main concern is with using this element to protect for close-in 138 kV faults (approximately 8000 A at 345 kV for a 138 kV bus fault) and the distance element will provide sensitivity for more remote faults, sensitivity for this element is not a great concern. Set this element to 800 percent of transformer nameplate to provide security for transformer inrush or roughly 4000 A at 345 kV (10,000 A at 138 kV).

7.2.1.3.3. Fixed Timer Settings

Ideally, this timer is set slower than the longest 138 kV line backup protection time and faster than any 345 kV line backup protection that reaches into the 138 kV system.

In practice, 345 kV relaying may not be able to detect 138 kV faults under normal conditions. If so, the timer should be set slightly higher than the longest 138 kV line backup protection time. Assuming a maximum 138 kV line backup time of 1.0 second, this relay may be set at 1.2 seconds.

If 345 kV relays are able to detect 138 kV faults under normal conditions, coordination with 345 backup protection may not be possible. In this case, the Transmission Owner must choose a specific time based on careful consideration of the consequences of the possible tripping sequence that might occur when a 138 kV fault is cleared in backup time or re-coordinate as necessary.

7.2.1.4. Simple System Setting and Reach Summary

	345 kV Side Setting	138 kV Side Setting	3-phase fault Reach into simple 138 kV system[1]
Phase Time Overcurrent Only	800	2000	36 Ω
Torque Controlled Phase Time Overcurrent	500	1250	60 Ω
Distance Element	NA	66 Ω @ 75 degrees	66 Ω

[1] Assumptions:

- 345 kV system is an infinite source
- 300 MVA transformer is 4 Ω at 138 kV
- Overcurrent Relay Setting = 80000/(4 + Reach in ohms)

7.2.1.5. Simple System Setting and Time to Trip Summary

	20,000 A 138kV Fault	10,000 A 138kV Fault	6,000 A 138kV Fault
Phase Time Overcurrent Only	0.4 seconds	0.77 seconds	1.74 seconds
Torque Controlled Phase Time Overcurrent	0.39 seconds	0.55 seconds	0.96 seconds
Distance Element with Fixed Timer[1]	1.2 seconds	1.2 seconds	1.2 seconds

[1] See section 7.2.1.3.3 for timer setting considerations

7.2.2. More Complex Systems

Most systems are not as simple as a single autotransformer feeding a single transmission line. Substations can have numerous transmission lines, multiple transformers in parallel, additional components such as shunt devices, and networked or looped lines. As the substation and its connected transmission system become more complex, so too does the application of backup protection.

A more complex system is shown in Figure 7.2.3 consisting of two autotransformers operating in parallel each feeding its own bus. In this example the connected 138 kV transmission lines are networked with significant fault current sources. This substation has two autotransformers operating in parallel feeding four transmission lines. In this configuration, the reach of the backup protection will be reduced by roughly one-half versus the simple system example due solely to the paralleled equivalent contributions of the two 300 MVA transformers. If any of the connected lines are short and provide additional fault current source contributions, the reach will be less than one-half of the reach calculated for the simple system. This reach limitation must be factored into system performance analyses when the Protection System design relies on autotransformer backup to clear faults for single Protection System failures. Figure 7.2.1 illustrates the impact on backup protection reach when multiple transformers are in parallel. In some cases it may be difficult, if not impossible, to achieve coordinated backup protection for more than close-in faults. In these cases the Transmission Owner may need to carefully consider the consequences of possible tripping sequences or re-coordinate where possible.

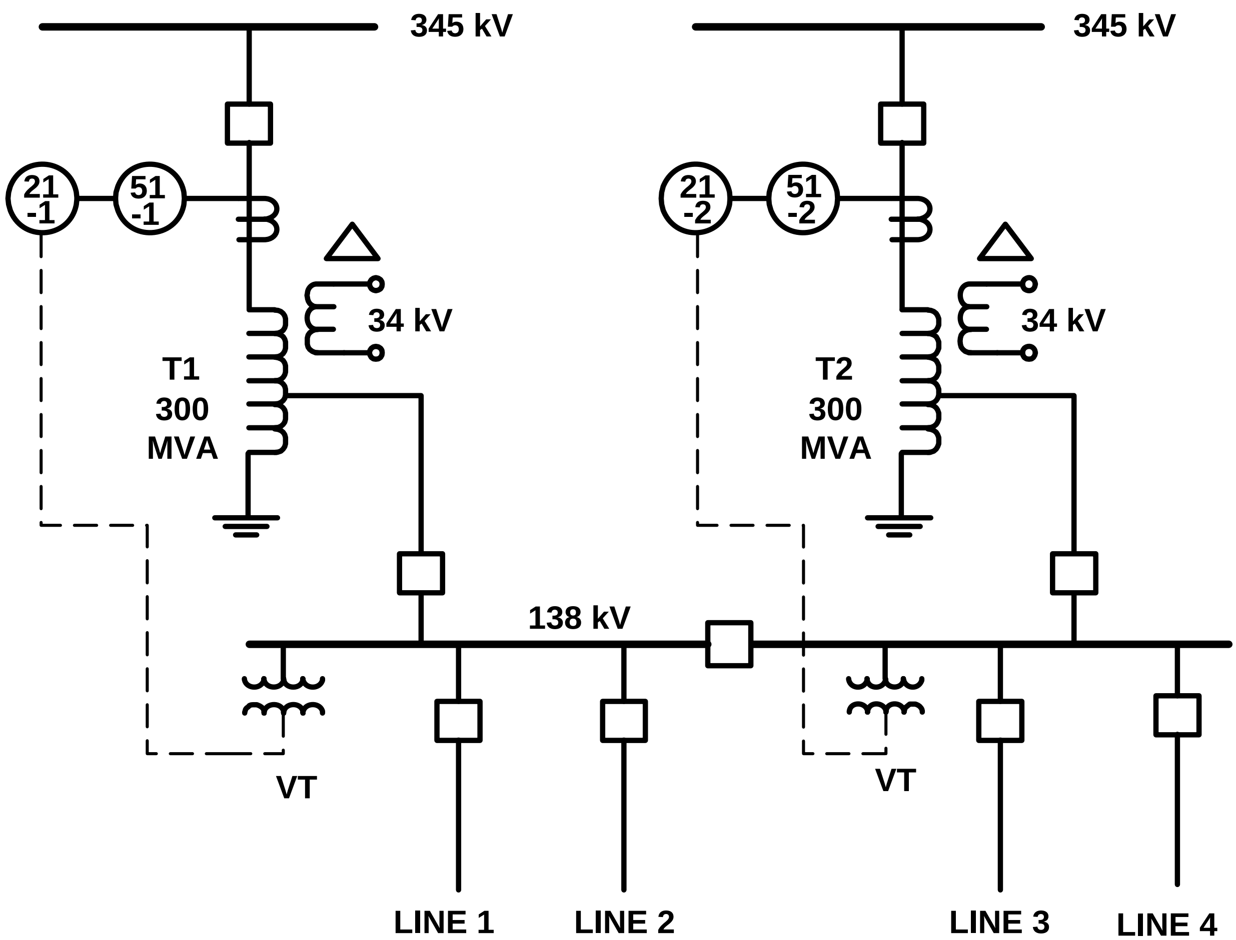


Figure 7.2.3 — More Complex System One-Line Used in Transformer Protection Example

Another problem for autotransformer backup in more complex systems is the inability of the local backup Protection Systems on the two transformers to provide selectivity based on the location of faults. The Protection Systems on both transformers may react similarly and operate simultaneously for faults because they will have similar or identical relay settings. In some cases it may be worthwhile considering backup protection that will split the bus to limit the number of system Elements interrupted, although for some bus configurations this may be impractical or add an undesired level of Protection System complexity. The relay practitioner will need to consider the application of backup Protection Systems applied on these complex systems and incorporate the appropriate degree of dependability and security to protect the assets and prevent degradation of reliability.

8. Conclusion

Transmission system events have shown that backup protection can play a significant role in preventing or mitigating the effects of Protection System or equipment failures.

Local backup inherently addresses single Protection System failures or failures of a circuit breaker to interrupt current while meeting NERC performance requirements and generally reduces the number of Elements that must be removed from the power system to clear the fault. Local backup may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme. Remote backup may also adequately perform this function and can also act as a safety net to reduce the extent of a power system disturbance during multiple Protection System failures or failures of circuit breakers to interrupt current. Application of remote backup protection, however, may be limited by the need to meet the requirements of NERC Reliability Standards designed to assure adequate power system response during single failures or severe system events.

The design of the power system and the local protection design practices dictate whether local or remote backup protection can be securely and dependably applied to meet NERC standards for power system and Protection System performance requirements. Careful examination of the overall interaction of Protection Systems may provide insight as to where additional local or remote backup can be applied to help mitigate the spread of an outage.

9. Recommendation

Large autotransformers are major capital investments and play a large role in the reliability and flexibility of the Bulk Electric System. Lead times for obtaining replacements are typically a minimum of six to twelve months; therefore, failures of these transformers can result in prolonged reduction in Bulk Electric System reliability and flexibility. Because of this, it is recommended that back up Protection Systems be applied to these assets to reduce the likelihood of damage due to prolonged through-fault currents caused by the failure of local or remote Protection Systems to clear the fault.

APPENDIX A – System Protection and Control Subcommittee Roster

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