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Optimizing Substation Grounding for Distribution System Faults

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SUMMARY

When designing a distribution substation grounding system, faults on either side of the power transformer may result in the controlling-case results considering touch and step voltages. Typical industry practice in the US involves designing a substation grounding system based on IEEE Std 80, IEEE Guide for Safety in AC Substation Grounding [1]. Within this guide, there is discussion on determining the "worst-case" fault to consider; however, many utilities ignore distribution system faults sourced from the low side of a typical delta-wye grounded distribution transformer. While this is reasonable for faults within the substation, it ignores the impacts of faults on the distribution feeder itself. Ignoring these faults assumes that a distribution system fault will always have an earth return current smaller than the maximum high-side fault current returning to remote substations. With increasing fault current availability on distribution systems and an increased awareness of fault impacts outside the substation fence, understanding distribution fault current returning through the earth back to the ground grid is becoming increasingly important.

There are a range of common assumptions for the earth return fault current for faults on the distribution system. The most conservative assumption for substations with four-wire distribution networks is that the full magnitude of the fault current available at the low-side transformer terminals is injected at the end of a feeder and it all returns through the earth. The multi-grounded neutral distribution system typical in US provides a better fault current return path than the earth. A much less conservative assumption is that a fault current inversely proportional to distance between the substation and the fault location on the feeder returns almost entirely through the neutral conductor. Calculating the appropriate earth return fault current is difficult to determine due to the extreme range of distribution system designs, grounding system performance, and soil characteristics.

This paper examines parametric analysis of faults throughout a variety of typical distribution feeders to determine the realistic portions of fault current that contribute to the Ground Potential Rise (GPR) of a substation under distribution system fault conditions. The analysis consists of varying significant input parameters including location of the fault on the

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distribution feeder, structure spacing, phase conductor size, neutral conductor size, downlead conductor size, substation size, and soil resistivity/layering. From this analysis, a practical maximum percentage of contribution of the system line-to-ground rated voltage expected to result in substation GPR can be determined for use in substation grounding analysis.

KEYWORDS

Substation, grounding, distribution, fault current, touch voltage, ground potential rise

INTRODUCTION

A substation's GPR is determined by the amount of zero-sequence ground fault current that returns to the source through the grounding system and the grounding system impedance. For a stand-alone transmission substation with no additional connections to earth (such as shield wires and neutrals) where all ground fault sources are remote, this is a simple determination: GPR (a voltage) equals the total fault current times the impedance of the grounding system. If there are alternative fault current return paths, such as shield wires and structure grounds, the fault current split factor methodology in IEEE Std 80 allows for a determination of how much of the total fault current flows through the local grounding system versus the shield wires and distribution neutrals.

However, in distribution substations, the delta-wye grounded transformer is the zero-sequence current source and is effectively local generation for faults on the low side of the transformer in the substation. Faults that occur within the substation have minimal current flowing through the earth as it simply circulates within the local grounding system, and thus does not produce a significant GPR. For faults on the distribution line outside of the substation grounding system, some current will flow through the earth back to grounding system and into the distribution transformer, producing a GPR.

Distribution faults have often been considered to have no earth return current (no GPR) or the full fault current to be conservative. The no-GPR scenario relies on the assumption that all current will return on the neutral, or that the fault is only analyzed in the substation, neither of which are accurate. The conservative approach produces the same GPR as if all current flowed through earth (none on the neutral) for simplicity. This second option is a conservative assumption that may result in significant over-design of the grounding grid as much of the distribution fault current will return through the distribution neutral (if a four-wire system is used) to the substation. This neutral portion of the current will not contribute to the GPR of the substation and only the percentage that flows through the earth back to the substation is necessary to consider. Additionally, faults further down the distribution line will decrease in total zero-sequence ground fault magnitude but increase in ratio of current flowing through the earth versus the neutral, making the determination of actual GPR very non-linear.

Using software that considers both current flow and magnetic field coupling, a determination can be made of how ground fault current returns through the earth and neutrals to distribution substation grounding system and how it results in GPR. For the purposes of this paper results are presented in terms of percentage the full GPR that can be expected for an infinite bus low-side fault injected directly into the full impedance of the grounding system, or the system line-to-neutral voltage. This resulting GPR can be compared to the GPR of transmission faults (through traditional analysis) to see if the distribution faults are of concern, while also considering impacts of clearing time and fault X/R ratio.

MODELING APPROACH

Distribution system designs are complicated and vary significantly from one region and/or utility to another. The factors that determine the percentage of fault current from a distribution fault that produces substation GPR are also widely varied, including the location of the fault on the distribution feeder, structure spacing, phase conductor size, neutral conductor size, downlead wire size, substation size, and soil resistivity/layering. To examine the variety of combination of scenarios that would produce the results desired, hundreds of cases were developed in a detailed grounding system analysis software package. Input data was varied using a range of representative inputs based on a large multi-state utility's system. Preliminary analysis determined which parameters that led to "worst-case" results, allowing optimization of further case runs. Ultimately the following inputs were considered:

- Phase conductors (8 total considered) varying from #6 AWG ACSR up to 336 kcmil ACSR
- Neutral conductors (6 total considered) varying from #6 AWG ACSR up to 4/0 AWG ACSR
- Downlead (pole ground) conductors (6 total considered) varying from #6 AWG copper to 4/0 AWG copper, attached to a single ground rod on the base of each pole
- Small, medium, and large distribution substation grounding systems with dimensions from 100 feet by 100 feet up to 500 feet by 500 feet
- Distribution circuit pole spacing of either 300 feet or 500 feet between poles
- Fault locations every 1,500 feet (10%) along distribution feeder (up to three miles out)
- Ten various soil resistivity models representing a range of soil structures with various high and low resistivity layers (see Table 1)

Table 1: Soil Resistivity Models

GPR (Highest-to-Lowest)	Soil Layer	Resistivity (Ω-m)	Thickness (ft)
Model #1 (Extreme Case)	Top	10	3
	Bottom	5,000	Infinite
Model #2	Top	10	3
	Bottom	1,000	Infinite
Model #3	Top	1,000	3
	Middle	10	20
	Bottom	1,000	Infinite
Model #4	Top	10	10
	Bottom	1,000	Infinite
Model #5	Top	10	3
	Middle	1,000	20
	Bottom	10	Infinite
Model #6	Top	10	10
	Bottom	100	Infinite
Model #7	Top	100	3
	Middle	10	20
	Bottom	100	Infinite
Model #8	Top	1,000	10
	Bottom	10	Infinite
Model #9	Top	10	3
	Middle	100	20
	Bottom	10	Infinite
Model #10	Top	100	10
	Bottom	10	Infinite

Figure 1 below shows a simplified version of the models and key parameters described above.

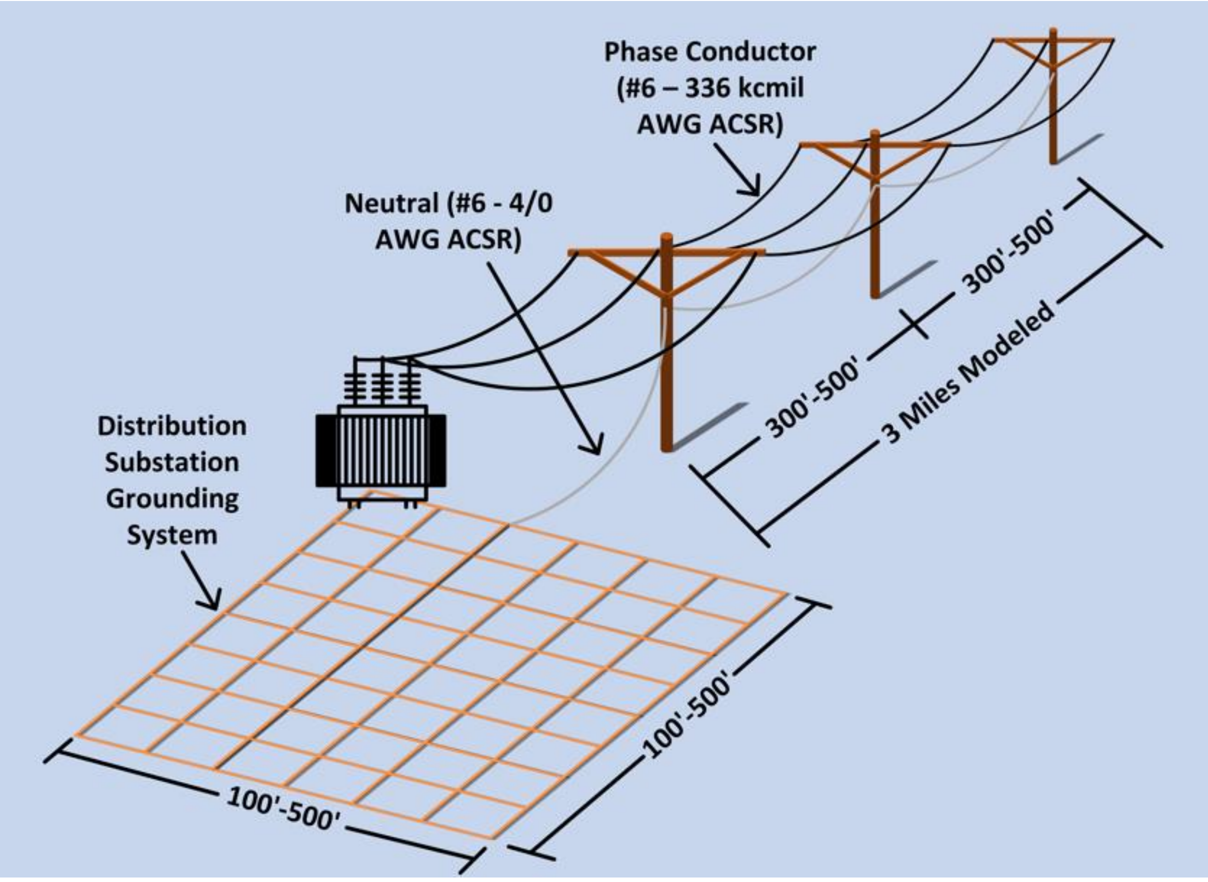

Figure 1: Simplified Diagram of Model and Key Inputs

Two additional factors in the performance of the substation grounding system were not considered in this specific analysis, but must for specific projects: fault clearing time, and X/R ratio. The X/R ratio generally has a small impact on the results but clearing time differences between transmission and distribution faults may vary significantly. For example, many transmission systems have a backup clearing time of 0.5 seconds or less, but a distribution feeder may rely on transformer backup overcurrent protection which may take a second or longer to clear distribution feeder faults if the feeder breaker or relay fails. Where there is a difference in clearing times, especially if significant), a lower magnitude GPR from a distribution feeder fault may result in greater risk to a person than a higher magnitude transmission system fault that has a shorter duration.

The actual models developed applied a fixed (arbitrary) 10 kV line-to-ground zero impedance voltage source at the substation. Faults were simulated every 10% of the feeder length along the distribution feeder with current magnitudes calculated based on the impedance of the phase conductor and total neutral/ground return path. The resulting GPR from the substation grounding system for each simulated fault with the variety of parameters was then compared to this total 10 kV energization to produce the results of the analysis.

INITIAL ANALYSIS

A large variety of case runs were performed by applying different conductor size combinations until it was determined which combinations yielded the highest and lowest substation GPR. These resulting highest- and lowest-GPR combinations were then applied to all three substation ground grid sizes and all ten soil resistivity models. Table 2 displays the final chosen conductor size combinations used for the remainder of the analysis, representing the extremes of cases (largest and smallest wire sizes) considered. Large phase conductors result in the highest GPR at the substation while smaller phase conductors result in the lowest GPR (primarily by reducing total available fault current at the fault location). Neutral wire sizes also impact the path of current as larger neutrals allow more current to flow on the neutral. However, only typical neutrals were considered for the corresponding phase conductor.

Table 2: Final Conductor Size Selections

GPR SCENARIO	PHASE CONDUCTOR	NEUTRAL AND DOWNLEAD CONDUCTOR
Highest	Oriole (336 kcmil 30/7)	Penguin (#4/0)
Lowest	Turkey (#6 AWG)	Turkey (#6 AWG)

As additional cases were explored, soil models 1 and 2 (from Table 1) produced the worst-case (most conservative) results. Since a soil structure such as case 1 would be very rare to find (generally only in a location with significant moisture with a shallow layer of soil over solid rock), all results presented in this paper are based on soil model 2 except for the soil variation section. This is still a generally conservative approach for most locations.

PRIMARY RESULTS

The following plots show results along the distribution feeders, representing various substation sizes combined with the extremes analyzed for conductor size (shown in Table 2) and span length between poles (300- or 500-foot spans). Plots were terminated at approximately 1.5 miles from the substations as all "worst-case" faults occurred within this distance. Faults further down a circuit would have significantly reduced total fault current, limiting the current return to the substation through any path.

Figures 2 through 3 show these results for a 500-foot, 300-foot, and 100-foot square substation respectively.

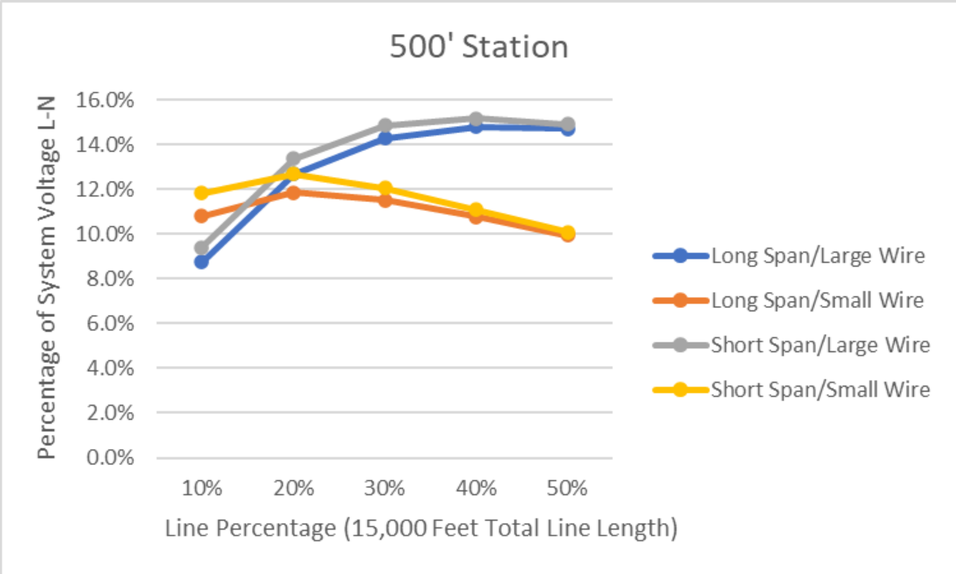

Figure 2: GPR Percentage of System Line-to-Neutral Voltage for a Large Substation

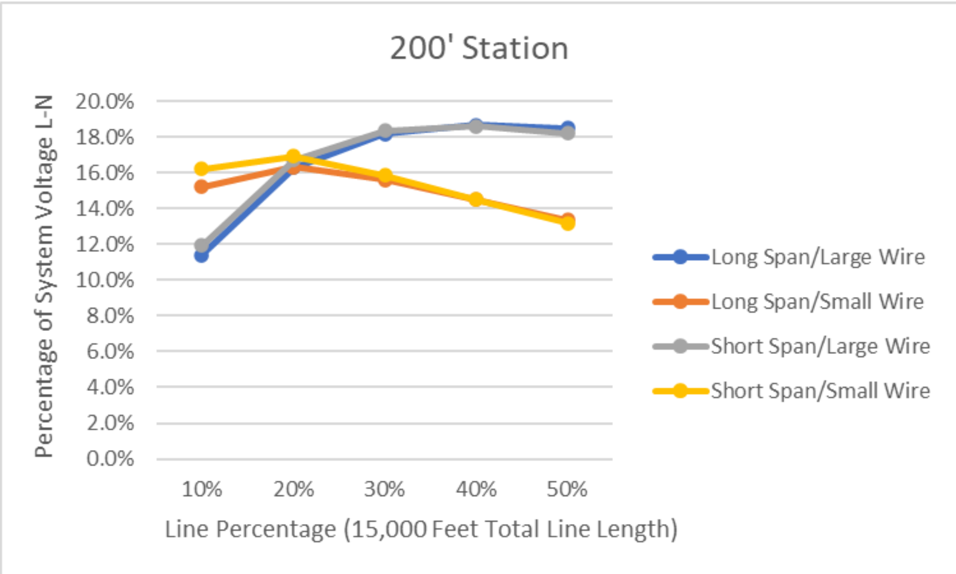

Figure 3: GPR Percentage of System Line-to-Neutral Voltage for a Medium Substation

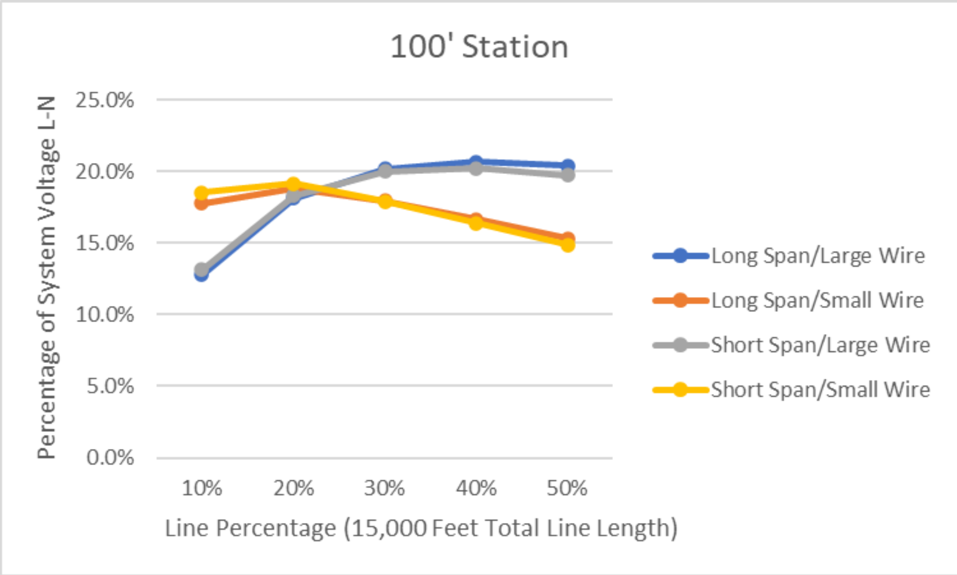

Figure 4: GPR Percentage of System Line-to-Neutral Voltage for a Small Substation

The general behavior of faults along the circuits is consistent despite substation size, namely that the "worst-case" location was typically around 0.5 to 1.5 miles from the substation and that larger wires pushed this distance further down the circuit (fault currents remain higher for a longer distance). Span length (thus resulting number of pole grounds along the circuit) has minimal impact. A smaller substation has higher resistance, resulting the fault current decreasing more for faults down a circuit, reducing total GPR. This results in slightly more of the current contributing to GPR, peaking around 20% of the system voltage for a small substation.

SOIL IMPACTS

The primary results above show that with some of the worst-case soil resistivity models, only 20% or less of the system line-to-ground voltage will contribute to GPR at a smaller substation. Based on this, a design engineer could simply consider 20% of the total fault current from a delta-wye grounded distribution transformer in the grounding system analysis. It should also be noted that this current would be limited to fault current sourced from the power transformer, and not contributions from any distributed energy resources along the distribution feeder, as those contributions would return to those sources, not the substation. Larger substations, using the same near worst-case soil resistivity models show the maximum contribution peaking at about 15% of the total current.

The "best-case" soil was soil model 10 from Table 1, representing a medium resistivity layer over a very low resistivity soil layer. With this soil scenario, as little as a maximum of 1% of the total distribution fault would contribute to the GPR of a large substation (shown in Figure 5 below), or as high as 8% for a small substation (shown in Figure 6 below). In these lower resistivity soils, the impact of span length also starts to have an additional impact on results. Particularly for a large substation in low resistivity soil, the approach some utilities use of ignoring distribution faults could make sense due to the extremely low percentage of current that actually impacts the substation GPR.

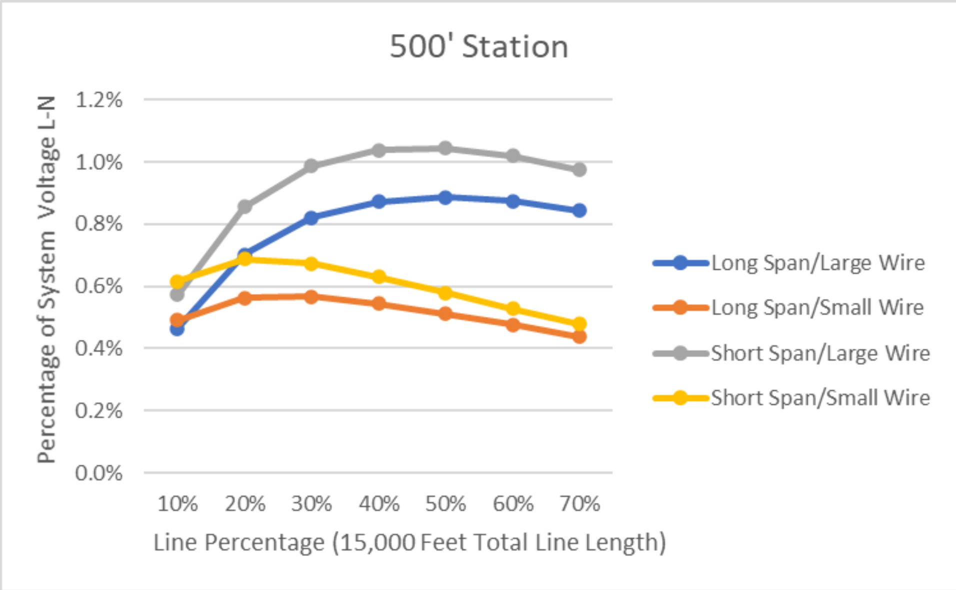

Figure 5: Percentage of Maximum GPR for a Large Substation with Low Resistivity Soil

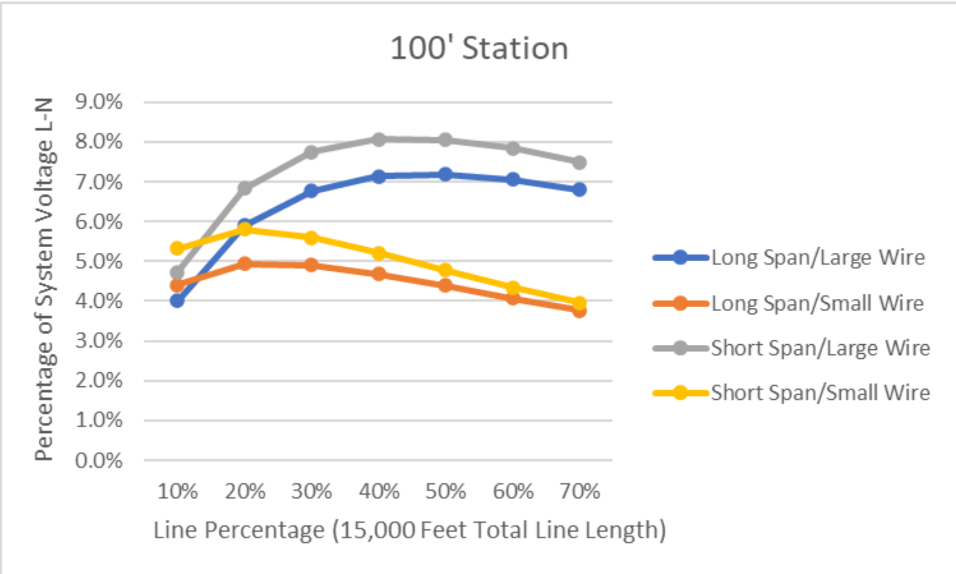

Figure 6: Percentage of Maximum GPR for a Small Substation with Low Resistivity Soil

CONCLUSIONS

Substation size, soil resistivity, and conductor sizes have the largest impact on the behavior of substation GPR for distribution feeder faults. The results from this study indicate that smaller substations and/or larger phase and neutral conductors result in a greater amount of the maximum possible GPR impacting the substation grounding system. Where smaller phase conductors are used, the worst-case location is generally within about half a mile of the substation; larger phase conductors may push this out further down the feeder. Generally, the faults producing the highest GPR are about one-half to one mile down the distribution circuit where the fault currents are still relatively high, but the impedance of the neutral is higher than faults immediately outside the substation, forcing more current to return through earth.

After compiling the resulting data from the study, the actual GPR value falls in a range of about 1% to 20% of the voltage source (line-to-neutral voltage). When comparing transmission and distribution faults, the resulting GPR (i.e. 20% of the distribution line-to-ground voltage rating and the calculated transmission GPR) can be compared directly, assuming similar clearing times. If a distribution fault has a longer clearing time, the factor may need to be reduced, or both transmission and reduced distribution fault scenarios can be analyzed in an advanced grounding software to determine which one results in the greatest GPR. If the substation is large and in low resistivity soil, the GPR for a distribution system fault may effectively be negligible.

Ultimately, every substation grounding system design situation is unique, but this analysis indicates that in a majority of scenarios, a distribution system fault will not result in the worst-case scenario for substation grounding analysis and thus can often be neglected. At a minimum, a significant reduction can be made to the impacts of distribution faults for low-side fault analysis to reduce possible significant over-design. However, in some designs, particularly when there is low high-side fault current, high low-side fault current, and poor (high resistivity) soil, the approach of simply ignoring distribution system faults may not provide a sufficient design for the grounding system. In these instances, the general guidance in this paper can provide a likely-conservative approach, or detailed modeling of distribution system impacts can be undertaken by the designer to provide a sufficient but reasonable design.

BIBLIOGRAPHY

[1] IEEE Std 80-2013, “IEEE Guide for Safety in AC Substation Grounding”