

## In Search of Z-Zero

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Traditionally, the calculation of transmission line impedance has involved conductor properties and spacing of the three phase conductors of the line in question, plus any shield wires. This has been found to produce sufficiently accurate results for positive sequence impedance –  $Z_1$  – and in many areas it produces acceptable results for the zero sequence impedance –  $Z_0$ . The analysis of ground fault events indicates that there is a problem with the zero sequence results in urban areas. Portland General Electric (PGE) has noted a tendency for overreach of ground overcurrent relays on much of the system. PacifiCorp (PACW) has also noted a long standing tendency for ground fault currents in the Portland area to be higher than predicted by their model.

This paper highlights some of the on-going work at PGE to find more accurate line models; the search for z-zero.

Given the low incidence of lightning in the PGE service territory, there is almost no shield wiring on the system. Historically, line impedance has been calculated using equivalent spacing of the three phase conductors and equations such as (1) and (2) from Blackburn's Symmetrical Components book [1]:

$$Z_1 = r_a + j * (X_a + X_d) \quad (1)$$

$$Z_0 = r_a + r_e + j * (X_a + X_e - 2 * X_d) \quad (2)$$

where

$r_a$  = resistance of a single conductor of GMR

$GMR$  = Geometric Mean Radius of the conductor under consideration

$r_e$  = 0.286, the resistance of the ground return

$$X_a = j * 0.2794 * \log \frac{1}{GMR}$$

$$X_d = j * 0.2794 * \log \sqrt[3]{D_{ab} D_{bc} D_{ca}}$$

$$X_e = j * 0.8382 * \log D_e$$

$$D_e = 2160 * \sqrt{\frac{\rho}{f}}$$

$D_{ab}$ ,  $D_{bc}$ ,  $D_{ca}$  = distance from conductors a to b, b to c, c to a

$\rho$  = bulk resistivity of earth

Similar equations are found in many texts and reference manuals. The constants used assume impedances in ohms per mile at 60Hz; other values will be found for other unit lengths or frequencies.

The zero-sequence impedance discrepancies noted in the Portland area indicate that there might be more to the picture than just the three conductors of the transmission circuit. Using the matrix

methods of Chapter 4 of Anderson [2], a MathCAD worksheet was developed that could solve for the impedances of a system with some number (m) of 3-phase lines and some other number (n) of grounds. Due to limitations in how MathCAD parses matrices, the worksheet requires the presence of at least two grounds for all calculations, but will accept grounds that are sufficiently small, have sufficient resistivity, and are sufficiently far away from the phase conductors as to have no impact on the results. This allows a single worksheet to be used to solve all cases but does require up to two fictitious ground conductors for each line configuration. Each of the m-lines is assumed to consist of 3 phase conductors; bundled lines need to be entered as equivalent conductors. The m-line capability was included to allow the calculation of mutual impedances between lines in addition to the self impedances of the line. The worksheet performs a matrix reduction to create a 3\*m by 3\*m matrix of equivalent conductor impedances and a 3\*m by 3\*m matrix of sequence impedances. The conductor impedance matrix includes the self impedance of each conductor and the equivalent mutual impedance between each conductor and all other phase conductors under consideration. The sequence impedance matrix includes the sequence impedances of each line as well as the mutual couplings between each sequence and all other sequences of all lines under consideration. Generally, only the positive-sequence self impedance, zero-sequence self impedance, and zero-sequence mutual impedances are output for use in system models.

The following matrices are from the multiple line example discussed in the next section (m=3, n=2), for the case with a 4/0 ACSR neutral and a  $\rho_{\text{earth}}$  of 10Ωm. The matrix  $Z_{\text{abcg}}$  includes all eleven (3\*m+n) conductors; ABC for line 1, ABC for line 2, ABC for line 3, and the two grounds.

$$Z_{\text{abcg}} = \begin{pmatrix} 0.35 + 1.31j & 0.1 + 0.61j & 0.1 + 0.52j & 0.1 + 0.53j & 0.1 + 0.52j & 0.1 + 0.48j & 0.1 + 0.36j & 0.1 + 0.35j & 0.1 + 0.37j & 0.1 + 0.55j & 0.1 + 0.35j \\ 0.1 + 0.61j & 0.35 + 1.31j & 0.1 + 0.61j & 0.1 + 0.52j & 0.1 + 0.53j & 0.1 + 0.52j & 0.1 + 0.36j & 0.1 + 0.35j & 0.1 + 0.35j & 0.1 + 0.5j & 0.1 + 0.36j \\ 0.1 + 0.52j & 0.1 + 0.61j & 0.35 + 1.31j & 0.1 + 0.48j & 0.1 + 0.52j & 0.1 + 0.53j & 0.1 + 0.36j & 0.1 + 0.36j & 0.1 + 0.37j & 0.1 + 0.46j & 0.1 + 0.36j \\ 0.1 + 0.53j & 0.1 + 0.52j & 0.1 + 0.48j & 0.35 + 1.31j & 0.1 + 0.61j & 0.1 + 0.52j & 0.1 + 0.34j & 0.1 + 0.33j & 0.1 + 0.34j & 0.1 + 0.55j & 0.1 + 0.33j \\ 0.1 + 0.52j & 0.1 + 0.53j & 0.1 + 0.52j & 0.1 + 0.61j & 0.35 + 1.31j & 0.1 + 0.61j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.5j & 0.1 + 0.33j \\ 0.1 + 0.48j & 0.1 + 0.52j & 0.1 + 0.53j & 0.1 + 0.52j & 0.1 + 0.61j & 0.35 + 1.31j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.34j & 0.1 + 0.46j & 0.1 + 0.33j \\ 0.1 + 0.36j & 0.1 + 0.36j & 0.1 + 0.36j & 0.1 + 0.34j & 0.1 + 0.33j & 0.1 + 0.33j & 0.23 + 1.24j & 0.1 + 0.58j & 0.1 + 0.54j & 0.1 + 0.35j & 0.1 + 0.45j \\ 0.1 + 0.35j & 0.1 + 0.35j & 0.1 + 0.36j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.58j & 0.23 + 1.24j & 0.1 + 0.58j & 0.1 + 0.34j & 0.1 + 0.5j \\ 0.1 + 0.37j & 0.1 + 0.35j & 0.1 + 0.37j & 0.1 + 0.34j & 0.1 + 0.33j & 0.1 + 0.34j & 0.1 + 0.54j & 0.1 + 0.58j & 0.23 + 1.24j & 0.1 + 0.35j & 0.1 + 0.53j \\ 0.1 + 0.55j & 0.1 + 0.5j & 0.1 + 0.46j & 0.1 + 0.55j & 0.1 + 0.5j & 0.1 + 0.46j & 0.1 + 0.35j & 0.1 + 0.34j & 0.1 + 0.35j & 0.77 + 1.46j & 0.1 + 0.33j \\ 0.1 + 0.35j & 0.1 + 0.36j & 0.1 + 0.36j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.33j & 0.1 + 0.45j & 0.1 + 0.5j & 0.1 + 0.53j & 0.1 + 0.33j & 0.53 + 1.33j \end{pmatrix} \frac{\Omega}{\text{mi}}$$

The matrix is then reduced to incorporate the affects of the grounds into the phase conductors and results in  $Z_{\text{abc}}$ .

$$Z_{\text{abc}} = \begin{pmatrix} 0.36 + 1.08j & 0.1 + 0.39j & 0.09 + 0.31j & 0.1 + 0.3j & 0.1 + 0.3j & 0.09 + 0.28j & 0.08 + 0.17j & 0.08 + 0.16j & 0.08 + 0.16j \\ 0.1 + 0.39j & 0.35 + 1.1j & 0.09 + 0.41j & 0.1 + 0.3j & 0.09 + 0.33j & 0.09 + 0.33j & 0.08 + 0.17j & 0.08 + 0.16j & 0.08 + 0.15j \\ 0.09 + 0.31j & 0.09 + 0.41j & 0.35 + 1.12j & 0.09 + 0.28j & 0.09 + 0.33j & 0.09 + 0.35j & 0.08 + 0.18j & 0.08 + 0.17j & 0.08 + 0.18j \\ 0.1 + 0.3j & 0.1 + 0.3j & 0.09 + 0.28j & 0.36 + 1.09j & 0.1 + 0.4j & 0.09 + 0.32j & 0.08 + 0.15j & 0.08 + 0.14j & 0.08 + 0.14j \\ 0.1 + 0.3j & 0.09 + 0.33j & 0.09 + 0.33j & 0.1 + 0.4j & 0.35 + 1.11j & 0.09 + 0.42j & 0.08 + 0.16j & 0.08 + 0.15j & 0.08 + 0.14j \\ 0.09 + 0.28j & 0.09 + 0.33j & 0.09 + 0.35j & 0.09 + 0.32j & 0.09 + 0.42j & 0.34 + 1.13j & 0.08 + 0.16j & 0.08 + 0.16j & 0.08 + 0.16j \\ 0.08 + 0.17j & 0.08 + 0.17j & 0.08 + 0.18j & 0.08 + 0.15j & 0.08 + 0.16j & 0.08 + 0.16j & 0.21 + 1.05j & 0.08 + 0.38j & 0.09 + 0.33j \\ 0.08 + 0.16j & 0.08 + 0.16j & 0.08 + 0.17j & 0.08 + 0.14j & 0.08 + 0.15j & 0.08 + 0.16j & 0.08 + 0.38j & 0.22 + 1.03j & 0.09 + 0.36j \\ 0.08 + 0.16j & 0.08 + 0.15j & 0.08 + 0.18j & 0.08 + 0.14j & 0.08 + 0.14j & 0.08 + 0.16j & 0.09 + 0.33j & 0.09 + 0.36j & 0.22 + 1j \end{pmatrix} \frac{\Omega}{\text{mi}}$$

With the matrix reduced to 3\*m by 3\*m (9x9), the sequence transform can be performed to provide a matrix,  $Z_{012}$ , of all of the self and mutual sequence impedances.

$$Z_{012} = \begin{pmatrix} 0.54 + 1.84j & 0.02 - 0.03j & -0.01 - 0.03j & 0.28 + 0.94j & 0.01 - 0.03j & 0.01 - 0.02j & 0.25 + 0.5j & 0 + 0.01j & -0 + 0.01j \\ -0.01 - 0.03j & 0.26 + 0.73j & -0.05 + 0.03j & 0.01 - 0.02j & 0 + 0.03j & -0.02 + 0.01j & 0.01 - 0.01j & -0.01 + 0j & -0 - 0j \\ 0.02 - 0.03j & 0.05 + 0.03j & 0.26 + 0.73j & 0.01 - 0.03j & 0.02 + 0.01j & 0 + 0.03j & -0.01 - 0.01j & 0 - 0j & 0.01 + 0j \\ 0.28 + 0.94j & 0.01 - 0.03j & 0.01 - 0.02j & 0.54 + 1.87j & 0.02 - 0.04j & -0.01 - 0.03j & 0.24 + 0.45j & 0 + 0.01j & -0 + 0.01j \\ 0.01 - 0.02j & 0 + 0.03j & -0.02 + 0.01j & -0.01 - 0.03j & 0.26 + 0.73j & -0.05 + 0.03j & 0.01 - 0.01j & -0.01 + 0j & -0 - 0j \\ 0.01 - 0.03j & 0.02 + 0.01j & 0 + 0.03j & 0.02 - 0.04j & 0.05 + 0.03j & 0.26 + 0.73j & -0.01 - 0.01j & 0 - 0j & 0.01 + 0j \\ 0.25 + 0.5j & -0.01 - 0.01j & 0.01 - 0.01j & 0.24 + 0.45j & -0.01 - 0.01j & 0.01 - 0.01j & 0.39 + 1.74j & 0.02 + 0.01j & -0.03 + 0.01j \\ -0 + 0.01j & 0.01 + 0j & -0 - 0j & -0 + 0.01j & 0.01 + 0j & -0 - 0j & -0.03 + 0.01j & 0.13 + 0.67j & -0.03 + 0.02j \\ 0 + 0.01j & 0 - 0j & -0.01 + 0j & 0 + 0.01j & 0 - 0j & -0.01 + 0j & 0.02 + 0.01j & 0.03 + 0.02j & 0.13 + 0.67j \end{pmatrix} \frac{\Omega}{\text{mi}}$$

The worksheet results were compared to the worked examples in Anderson. With various constants truncated at the precision used in Anderson's calculations, the worksheet was found to produce the same results.

### Do Neutrals Matter?

With this tool at hand, inclusion of more than just the three phase conductors became manageable. That opened up the opportunity to do some experimentation; what does an underbuilt distribution neutral do to the line impedance? The results were enough to lead to an ongoing reevaluation of the impedances of all lines with underbuilt distribution.

Figure 1 shows PGE's standard 115kV line framing for tangent structures. Various combinations of this framing with an underbuilt distribution neutral can be evaluated. Two line configurations were considered in the following results. The line was evaluated with 795 AAC as the line conductor, 70 foot poles, and various neutrals. If the whole line is framed on the 70 foot transmission poles, the neutral will be about 38 feet above grade. If the line is constructed with a mix of transmission poles with shorter distribution poles in between, the neutral will be about 27 feet above grade.

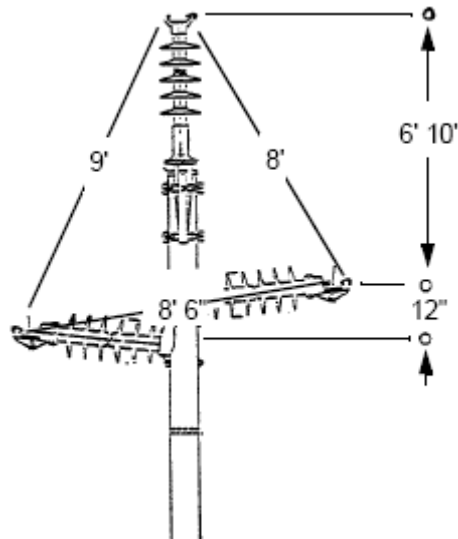


Figure 1

The affects of the neutrals are compared against the base case of three phase conductors alone. Neutral sizes range from #4 ACSR through 795 ACSR and #2 AAC through 795 AAC. The base

case uses the default bulk earth resistivity,  $\rho_{\text{earth}}$  value of  $100\Omega\text{m}$  and the comparison cases include  $\rho_{\text{earth}}$  values of both  $10\Omega\text{m}$  and  $100\Omega\text{m}$ .

Figure 2 shows  $Z_0$  relative to the base case, Figure 3 shows the relative reactive component  $X_0$ , and Figure 4 shows the relative resistive component  $R_0$ . As shown, the inclusion of the underbuilt distribution neutral can easily reduce the  $Z_0$  of the line to less than 80% of the  $Z_0$  calculated using only the three phase conductors. In all of the cases observed,  $X_0$  is less than the  $X_0$  of the base case. Because  $X_0$  is significantly larger than  $R_0$ , the decrease in  $Z_0$  closely matches the decrease in  $X_0$ . The resistive component  $R_0$  will increase for small neutral conductors and decrease for large neutral conductors.

The type of neutral conductor, AAC or ACSR, does not appear to influence the result. A decrease in  $\rho_{\text{earth}}$  can be seen to reduce  $R_0$ ,  $X_0$ , and  $Z_0$ . Closer spacing between the distribution neutral and line phase conductors correlates to a greater reduction in  $X_0$  and  $Z_0$  while increasing in  $R_0$ . The results for  $X_0$  and  $Z_0$  appear to trend to a limiting value with increasing neutral size while  $R_0$  continues to decrease with increasing neutral size. Neutral size becomes the dominant factor influencing  $R_0$ .

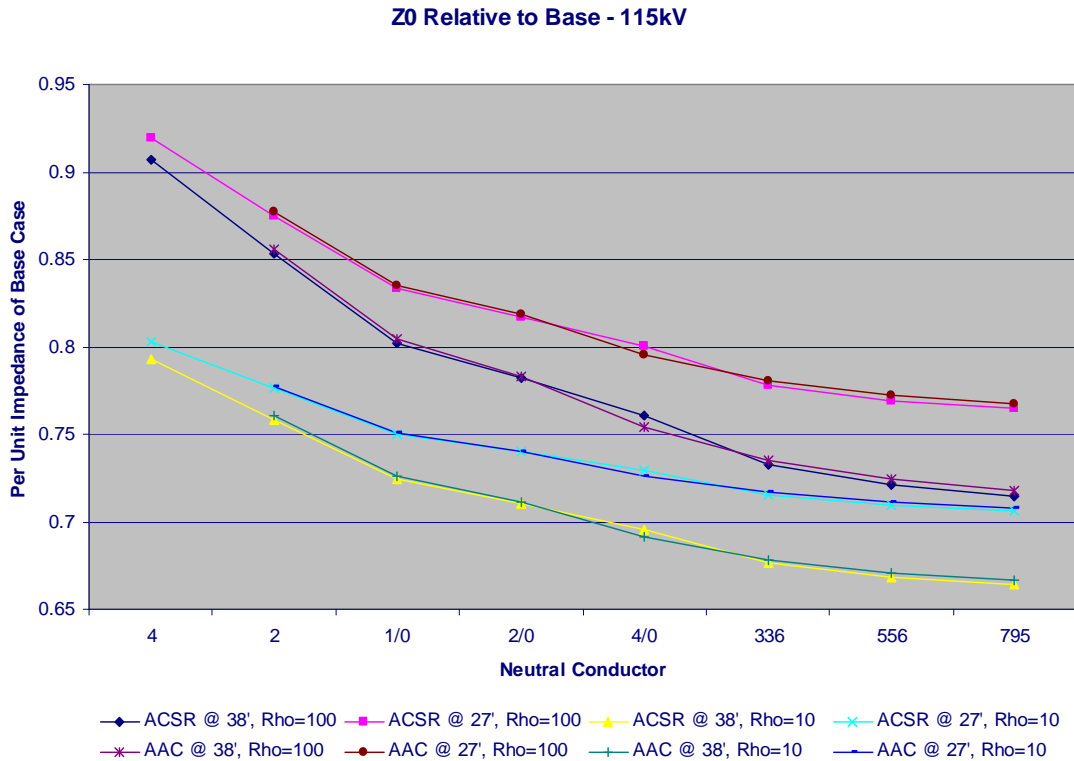


Figure 2

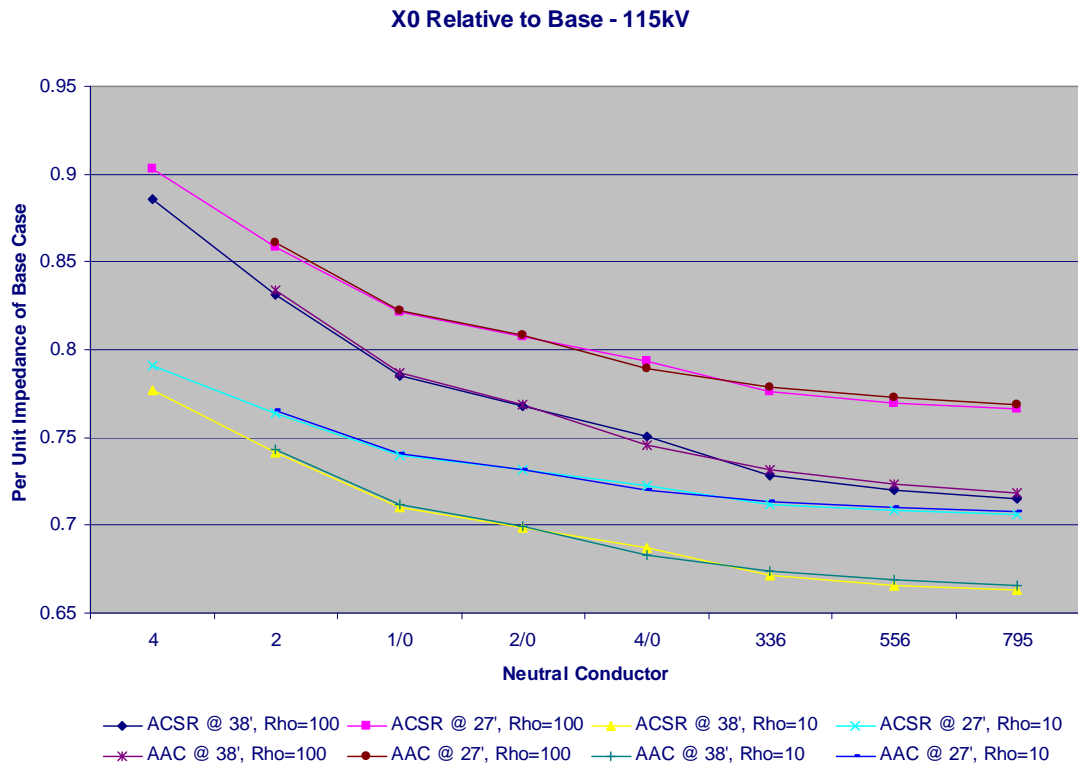


Figure 3

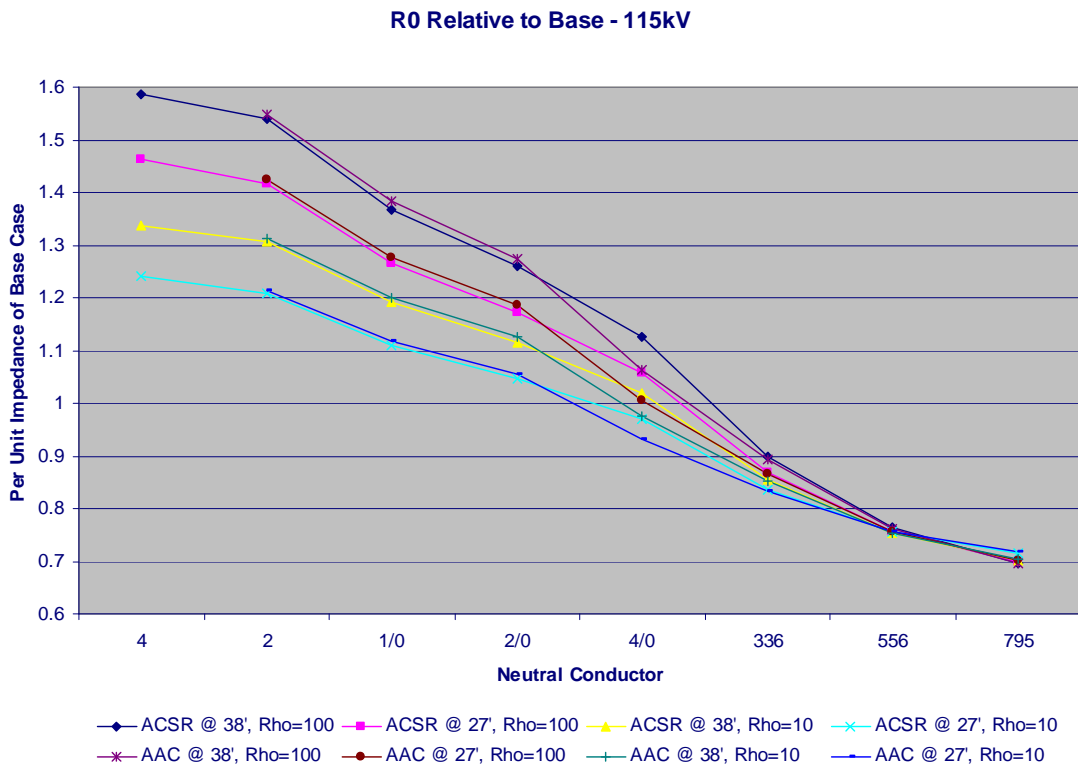


Figure 4

To look at the impact of line voltage, a 57kV line framing with tighter spacing was also evaluated. Figure 5 shows the framing for this line construction and Figures 6 through 8 show  $Z_0$ ,  $X_0$ , and  $R_0$  relative to the base case.

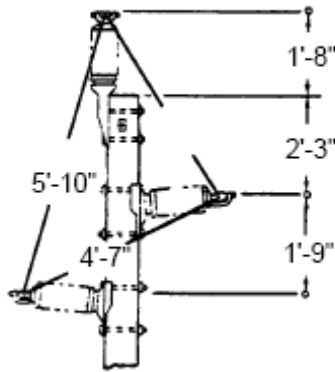


Figure 5

#### **$Z_0$ Relative to Base - 57kV**

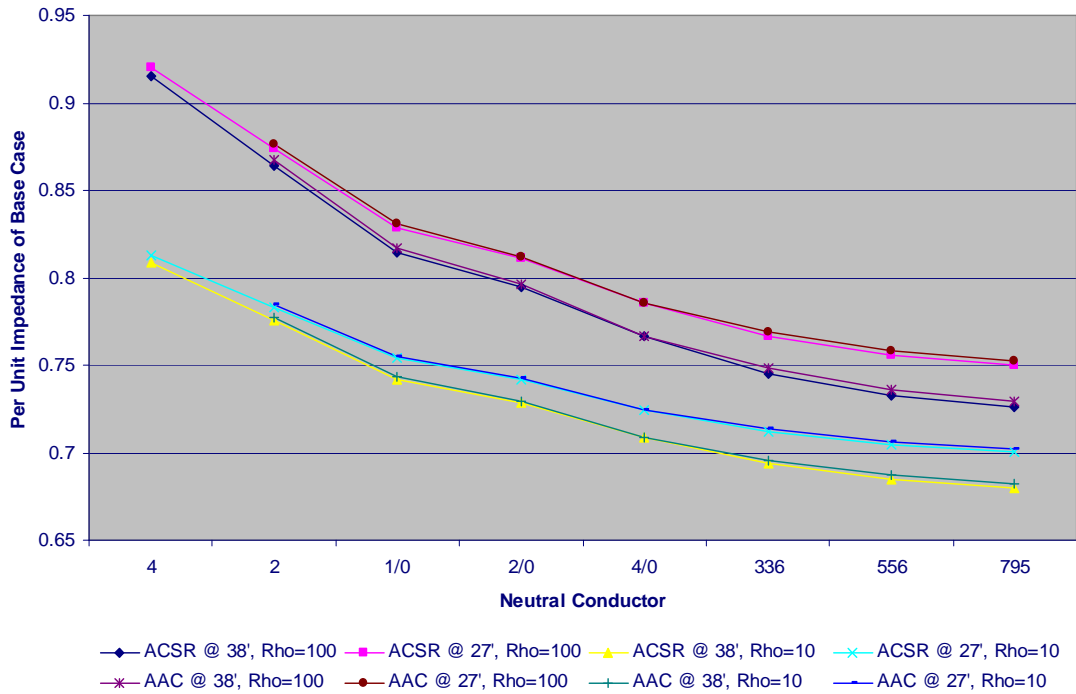


Figure 6

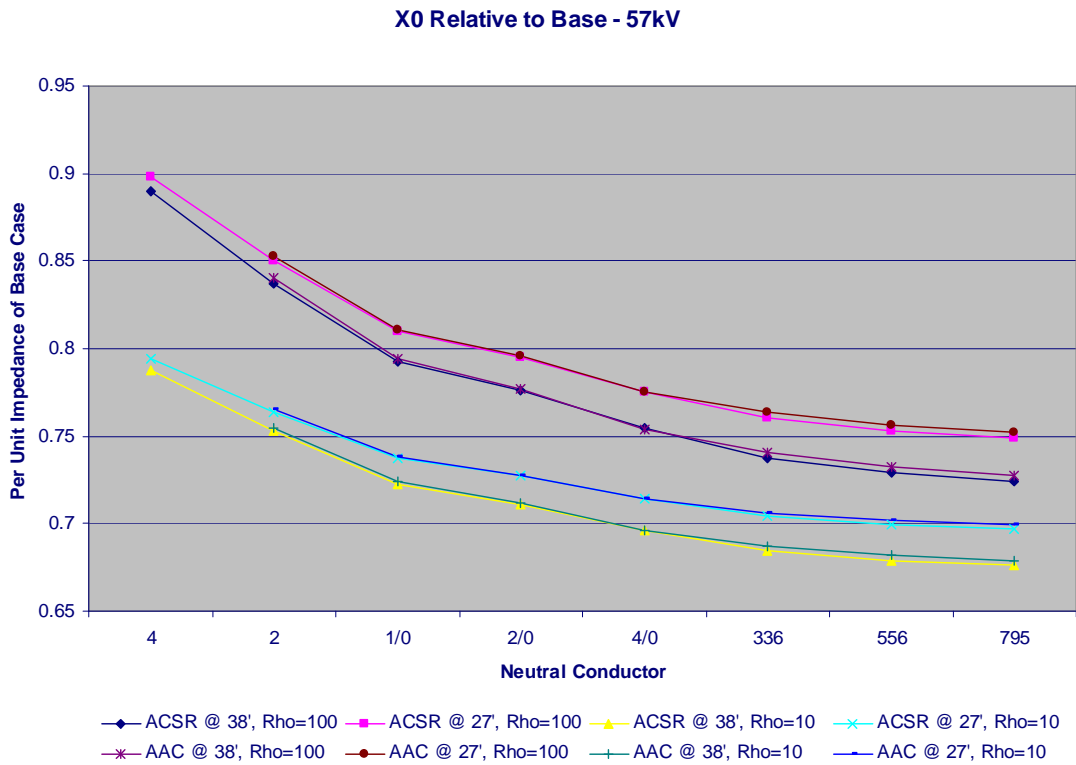


Figure 7

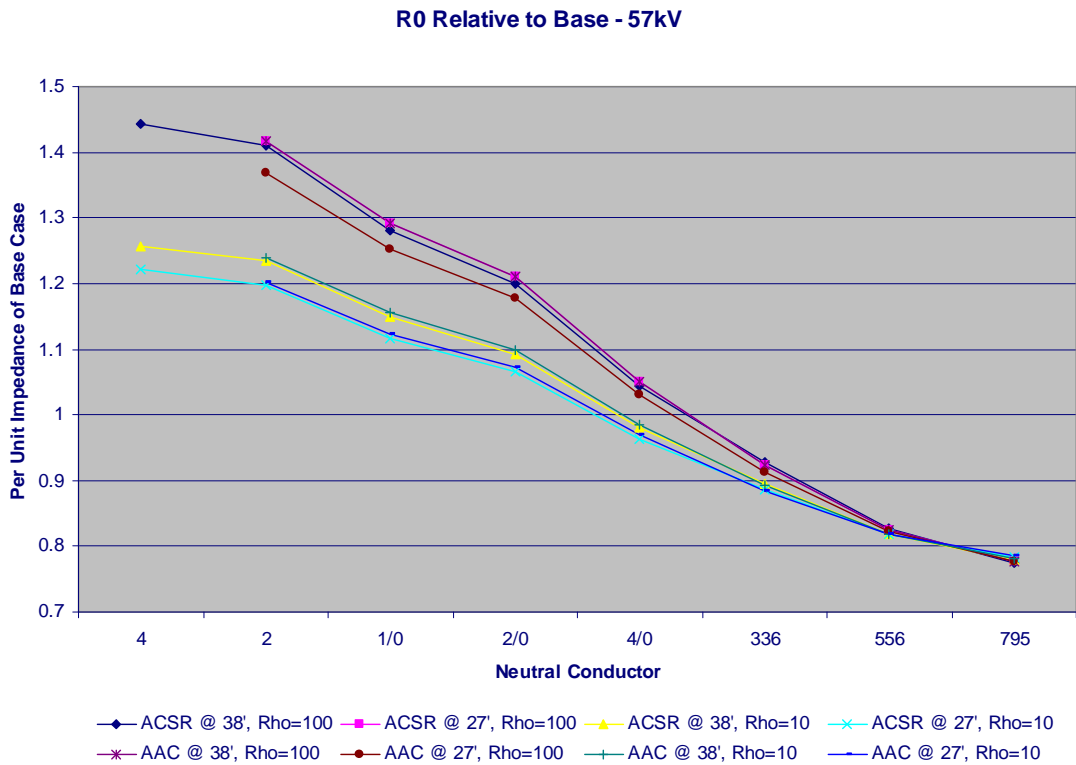


Figure 8

For all of the combinations discussed above, the positive-sequence impedance  $Z_1$  was compared to the base case  $Z_1$ . The greatest reduction in  $Z_1$  was less than 0.06%; the presence of a distribution neutral as no discernable affect on  $Z_1$ .

Another configuration studied involves multiple parallel lines with a distribution circuit below one of the lines. Figure 9 is a diagram from the MathCAD worksheet used for the calculations; it shows the placement of three lines and two grounds. Lines 1 and 2 are the two lines to the left, both 57kV on steel lattice towers, constructed soon after the turn of the 20th century with a shield wire. Line 1 is on the left and line 2 on the right side of the tower. The third line, Line 3, is an 115kV line with an underbuilt distribution circuit. The neutral is shown as the ground below the phase conductors. For this case, the ACSR neutral conductor is set at 38 feet, while the neutral size and  $\rho_{\text{earth}}$  are varied for comparison. The base case includes the shield wire and no neutral.

Figure 10 shows the resulting  $Z_0$  relative to the base case. Line 1 is 55.5 feet from the center line of Line 3 and shows a 10 to 15% reduction in  $Z_0$  compared to when the neutral is ignored. This indicates that neutrals do not need to be on the same structure as the line in question to cause a noticeable change in impedance.

Figure 11 shows the change in mutual impedance between pairs of lines due to consideration of the distribution neutral. A 2/0 ACSR neutral, with no change in  $\rho_{\text{earth}}$ , results in a 30% reduction of  $Z_{0m}$  between the 115kV line and either of the 57kV lines. With a 795 ACSR neutral and a change of  $\rho_{\text{earth}}$  to  $10\Omega\text{m}$ , the mutual coupling between the 115kV and 57kV lines is reduced by half from the base case.

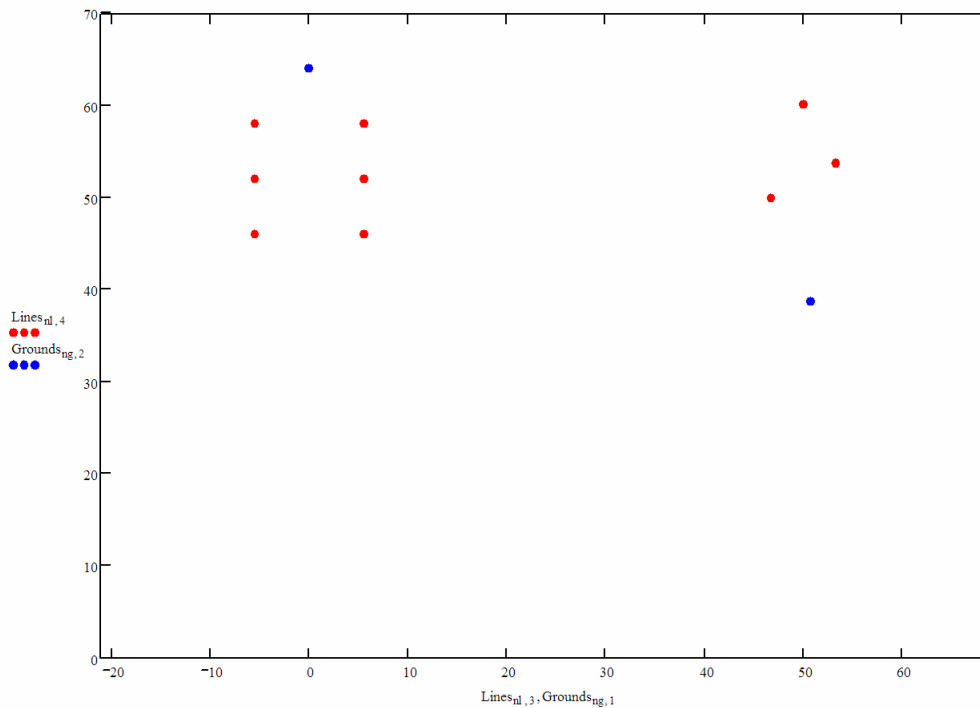
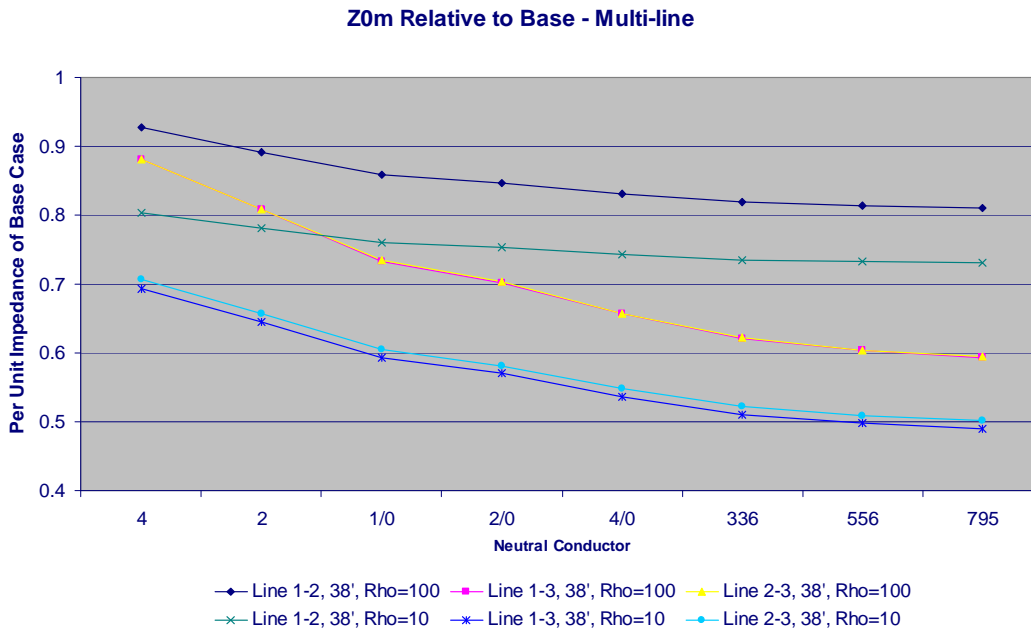
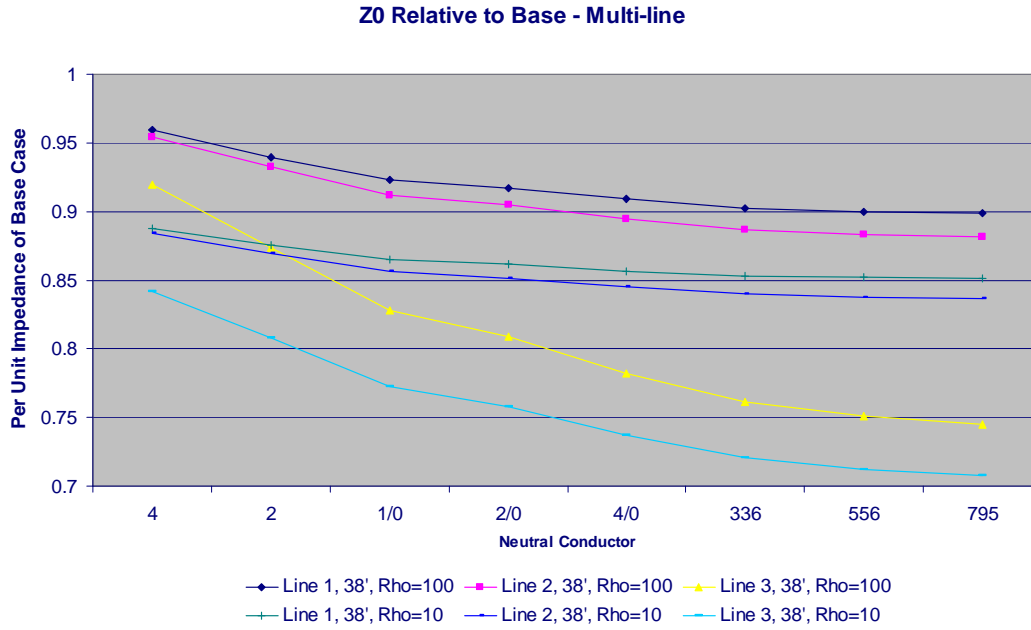


Figure 9



## Test Cases

Once it became apparent that distribution neutrals had a significant role in the calculation of line impedance, test cases were sought to see if the inclusion of the distribution neutral in the impedance calculations was enough to make the ASPEN OneLiner model match the fault currents seen by relays during actual faults. It was necessary to find faults with a known fault location and likely minimal fault resistance.

## Test Case 1

One such fault was readily at hand; on April 3, 2007, a circuit switcher failed at PacifiCorp's (PACW) Troutdale substation. PGE had three lines trip in response to this circuit switcher failure; undesired trips of the two unfaulted lines were both initiated by instantaneous ground directional overcurrent elements.

The three lines involved in this event connect to the west bus at Bonneville Power Administration's (BPA) Troutdale 230kV switchyard as shown in Figure 12. The lines, from shortest to longest, are Bluelake-Troutdale BPA, Linneman-Troutdale BPA, and Gresham-Troutdale BPA. The Linneman and Gresham lines share double circuit structures from Linneman to Troutdale BPA. Troutdale PACW substation is just outside Troutdale BPA substation and has taps from both the Gresham and Linneman lines. The lines in question are shown in the aerial map of Figure 13.

The fault to be evaluated was on the Gresham line at Troutdale PACW. On the first strike, the Troutdale BPA breaker on the Gresham line tripped instantaneously on directional ground overcurrent (67N). The Gresham breaker tripped by pilot relaying from Troutdale, but after the Troutdale breaker opened and before the Gresham breaker could open, the instantaneous 67N relay at Gresham picked up. The instantaneous 67N relay at Bluelake picked up and the Bluelake breaker tripped. Following these trips, the Gresham breaker remained open as it only recloses on to an energized line. The Troutdale BPA breaker reclosed into the fault and again tripped instantaneously. While the Troutdale BPA breaker was closed and the Bluelake breaker was open, the Linneman breaker was tripped by an instantaneous 67N relay. After the Troutdale BPA breaker tripped the second time and locked out, both the Linneman and Bluelake breakers successfully reclosed. Neither Linneman nor Bluelake should have operated for this event.

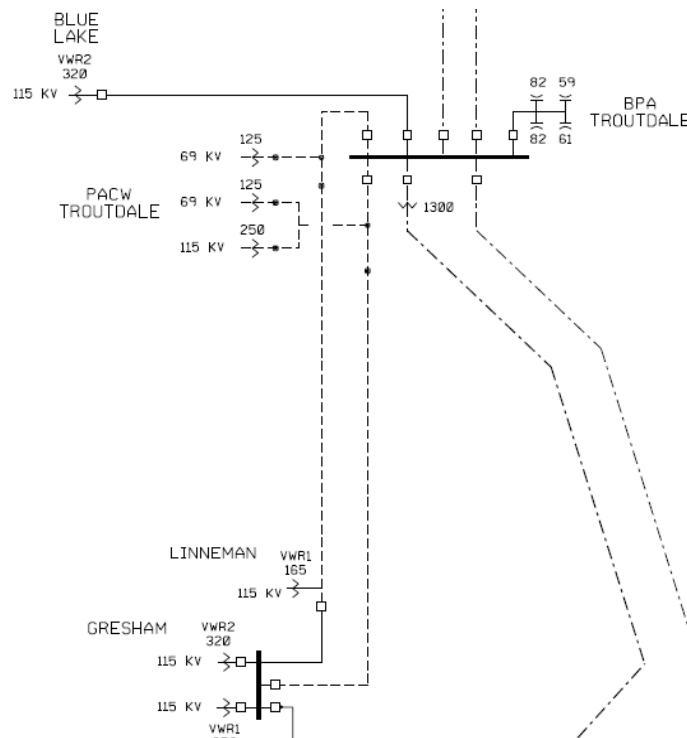


Figure 12



Figure 13

For this fault, the intended operation would be an instantaneous trip at Troutdale BPA, directional ground time picked up at Gresham and an instantaneous trip at Gresham via pilot relaying from Troutdale BPA. Troutdale BPA would have reclosed once, retripped and locked out, and neither Linneman nor Bluelake should have had any operations.

Could the addition of the affects of distribution neutrals and accounting for all line mutual couplings explain the observed results?

Table 1 shows current from the relay records and compares them with currents predicted by the system model in use at that time (Model 1) and the settings based on that model.

Location	Actual	Model 1	Setting
Gresham	3600	3240	7200
Gresham Troutdale Open	7300	10275	7200
Linneman		1590	5200
Linneman Gresh/BL Open	6250	4408	5200
Bluelake	3060	2425	3000
Bluelake Gresham Open		2465	3000

Table 1

As shown above, the model in use at the time predicted the Gresham breaker would trip after Troutdale BPA opened, but it predicted that none of the other stations have operations. The predicted currents are below the actual currents except for Gresham with the Troutdale BPA breaker open. The breaker at Gresham was tripped on transfer trip from Troutdale BPA and the remote end open condition lasted for less than one cycle. A longer duration may have allowed the recorded current to increase.



Figure 14



Figure 15

Could the model be improved to predict the operation of Bluelake and more accurately predict the currents seen?

In addition to the 230kV circuits directly involved, Figure 14 shows a number of 115kV lines, portions of which parallel the 230kV lines. All of the lines shown in Figure 14, plus distribution neutrals under any of the 115kV lines, were modeled and compared to the previous ASPEN OneLiner model.

With the line data updated, the subsequent model – Model 2 – was used to predict fault currents, as tabulated in Table 2.

Location	Actual	Model 2	Model 1	Setting
Gresham	3600	3165	3240	7200
Gresham Troutdale Open	7300		10275	7200
Linneman		2815	1590	5200
Linneman Gresh/BL Open	6250	5599	4408	5200
Bluelake	3060	2571	2425	3000
Bluelake Gresham Open		2684	2465	3000

Table 2

Model 2 predicted lower fault current on the faulted line, but it predicted higher current into the fault from the other lines. In order to verify that the Gresham-Troutdale BPA line data was not the issue, a simulation was run for a fault at Troutdale PACW on the Linneman line. This also showed a decrease in current on the faulted line and an increase on the coupled line. With this symmetry, the results were attributed to a more complete modeling of mutual coupling. In the original model, the Gresham and Linneman lines were coupled to each other, but no other couplings were modeled. In Model 2, and later models, each of the Gresham and Linneman lines has 7 mutual couplings and the Bluelake line went from no couplings to five.

This version of the model showed Linneman tripping with both the Gresham and Bluelake breakers open, but could not explain tripping at Bluelake.

The affects of ground resistivity were reviewed in an attempt to resolve this issue. The line impedances were recalculated with a  $\rho_{\text{earth}}$  of 10 $\Omega$ m. Over one half of the length of the Gresham and Linneman lines is adjacent to Fairview Creek. Between Bluelake and Troutdale BPA, the lines are in a wetland adjacent to the Columbia River. This fault, as do many PGE faults, happened during the wet season; the ground would be close to saturated even when not adjacent to open water.

The affect of distribution neutrals was also investigated. In Figure 15, the green lines represent the location of distribution neutrals. Although these neutrals are associated with many different distribution feeder circuits, they are connected to adjacent circuits at open tie switches on the phase conductors. In many areas, the affect of these neutrals is so significant that there becomes a second effective ground plane 25-40 feet above ground level.

With this change, Model 3 was evaluated and the results tabulated in Table 3

Location	Actual	Model 3	Model 2	Model 1	Setting
Gresham	3600	3302	3165	3240	7200
Gresham Troutdale Open	7300			10275	7200
Linneman		2954	2815	1590	5200
Linneman Gresh/BL Open	6250	6058	5599	4408	5200
Bluelake	3060	2539	2571	2425	3000
Bluelake Gresham Open		2625	2684	2465	3000

Table 3

The predicted currents are close to the actual values during the event, but further refinement was desired.

It was observed that the line  $Z_0$  impedances had decreased by 20% or more, but the fault currents had not increased proportionally, suggesting that the source impedance was an issue. Rather than trying to improve the model of all surrounding lines, the impedance of transformers supplying ground current to the fault was considered.

In *A Practical Guide to Short-Circuit Calculations* [3], St. Pierre suggests that transformer  $Z_0$  is about 85% of the transformer  $Z_1$ . Due to the lack of zero-sequence impedance data from transformer manufacturers, previous system models used transformers with  $Z_0$  equal to  $Z_1$ . Bluelake and Linneman each have one 230kV-115kV auto-transformer and Gresham has two.

With these four transformer zero-sequence impedances modified, the fault was studied again, with the results of Model 4, shown in Table 4.

Location	Actual	Model 4	Model 3	Model 2	Model 1	Setting (Model 4)	Setting (Old)
Gresham	3600	3771	3302	3165	3240	7100	7200
Gresham Troutdale Open	7300	10581			10275	7100	7200
Linneman		3350	2954	2815	1590	7200	5200
Linneman Gresh/BL Open	6250	6944	6058	5599	4408	7200	5200
Bluelake	3060	2845	2539	2571	2425	3700	3000
Bluelake Gresham Open		2956	2625	2684	2465	3700	3000

Table 4

The predicted fault currents were deemed to be sufficiently improved from those provided by the original model. Model 4 does not suggest the trip at Bluelake, but does suggest that the setting at Bluelake was too low and should have been at least 3600A. The 3700A value listed in Table 4 is based on a different contingency not included in the table. The remaining discrepancies between predicted results and those recorded by the relays may be due to use of assumed transformer  $Z_0$  impedances rather than tested values, not revising the impedance of adjacent lines, not revising the impedance of additional transformers, and not accounting for fault resistance. It is also probable that a  $\rho_{\text{earth}}$  value of  $10\Omega\text{m}$  was too low for the Gresham and Linneman lines while being too high for the Bluelake line. If settings based on Model 4 had been used, all three line relays would have operated properly with an acceptable margin for all currents recorded.

## **Test Case 2**

A second event with a known location occurred on March 8, 2004, when a lightning arrestor failed on the transformer at the Maxim Substation. Maxim is served by a tap from the radial St. Marys-Tektronix 115kV line. With the radial line, there were no concerns with overreach, but this case did provide a fault to test the system model. As shown in Figures 16 and 17, a portion of this line runs parallel to Tri-Met's Westside Max light rail and one track of a freight rail track. The light rail is "isolated" from earth but the resistance to earth over large distances can be fairly low. There is no particular attempt to isolate the freight rail tracks from earth and these are the closest of the three rail lines to the transmission line. Historical response of the light rail system to ground faults on adjacent transmission lines suggests significant current flow in the rails as a result of the fault currents in the line. Figure 16 shows the whole line while Figure 17 shows a portion with line and rail in more detail.

The previous system model predicted fault current of 14430A at this location while the relay recorded about 17,000A for the initial fault and on reclose. The relay setting was 10,080A. The line parameters were recalculated using a  $\rho_{\text{earth}}$  of  $10\Omega\text{m}$  plus distribution neutral, neglecting the rails. That model was not retained, but the results were not close enough to the actual fault values to be considered acceptable. The rails were then added to the line parameter calculations. All of the electrical conductor properties were not found for steel rail resulting in the need develop the needed parameters. The resistance of  $0.05\Omega/\text{mile}$  was available. An equivalent conductor diameter was determined, 9.05 inches, to produce a circle with the same circumference as the rail. Determination of a reasonable GMR required an iterative solution. The attempt was to produce reasonable results, not necessarily to arrive at the definitive value of GMR. Eventually, it was determined that a GMR of 0.5 feet was a workable value.

The revised model predicted fault current of 17,682A, which is much closer to the relay measurement of 17,000A. If fault resistance is considered,  $0.75\Omega$  of fault resistance lowers the predicted fault current to 17,020A. The Maxim station has a small ground grid and  $0.75\Omega$ , or higher, fault resistance to ground is reasonable.

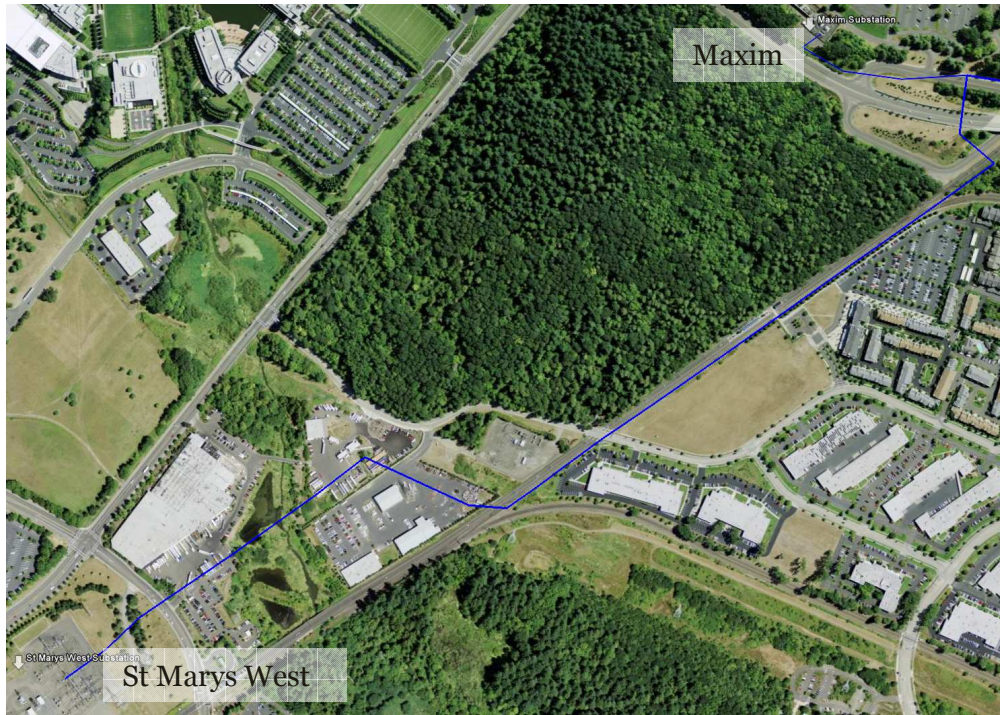


Figure 16

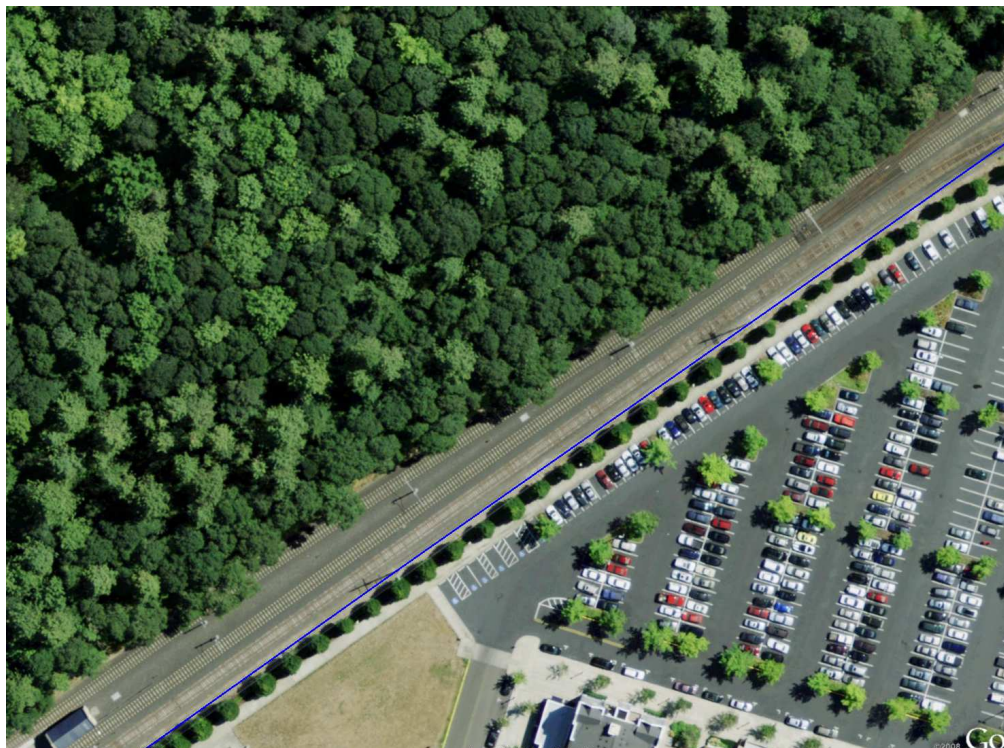


Figure 17

### **Test Case 3**

A third event occurred on May 29, 2007, when relays at Linneman on the Linneman-Tabor 115kV line operated for a fault about a half mile outside Tabor on an adjacent line. Unfortunately, this line is protected by an IRD-9 relay that provides no information other than trip indication. Before reevaluation of the parameters of the Linneman-Tabor line, the system model predicted that Linneman would see 4160A for this fault and the relay was set at 4320A. Because the relay tripped, and the instantaneous ground overcurrent relay targeted, we know the fault current exceeded 4320A, but the exact magnitude remains unknown. With the line parameters recalculated to include both the underbuilt distribution neutral and the distribution neutral on the opposite side of the road, the system model predicted that Linneman would see 4619A. The neutral on the opposite side of the road resulted in a 2-3% reduction in line  $Z_0$  beyond the reduction due to the underbuilt distribution neutral.

### **Conclusions and Recommendations**

Distribution neutrals in the vicinity of transmission lines can have a significant impact on the zero sequence circuit parameters of the line. Urban areas with a high density of neutrals will increase the impact. In the absence of detailed line calculations, it appears that reducing line  $X_0$  to 75 or 80% of the value arrived at when considering only the phase conductors will provide more accurate line impedance values when a distribution neutral is on the same pole as the line conductor. Detailed calculations or impedance measurements made in the field will always provide better results.

Evaluation of transformer  $Z_0$  used in system models should be examined. Setting  $Z_0=Z_1$  may be convenient, but this can contribute to predicted fault currents below those found during actual faults. If actual zero-sequence impedance data is not available, setting  $Z_0=85\%$  of  $Z_1$  per St. Pierre is suggested.

The use of a  $\rho_{\text{earth}}$  of 100 $\Omega\text{m}$  is the recommendation of many texts in the absence of actual test results, but this value may be too high. Ground that spends several months of the year near saturation may be more accurately represented by a lower value for  $\rho_{\text{earth}}$ . A reduced  $\rho_{\text{earth}}$  value can also be used to account for presence of a mesh of distribution neutrals covering large areas.

Transportation rails in the same corridor as transmission lines should be accounted for in the calculation of line parameters, but rail parameters as electrical conductors are not readily available.

Data from “good” faults with known locations and low fault resistance is valuable for system model validation.

### **Comments on Ground Overcurrent vs. Ground Distance**

While improved calculation of line  $Z_0$  can help in reducing overreach of ground overcurrent elements, the performance of ground overcurrent is dependent on knowing the source  $Z_0$  as well as the line  $Z_0$ . As the first Test Case showed, there can be significant reductions in line  $Z_0$  that are not matched by proportional increases in projected fault current because the line  $Z_0$  is only part of the total impedance. An under reaching ground distance element, on the other hand, is almost entirely dependent on the line  $Z_0$  and the source  $Z_0$  has much less impact. While the example provided showed that a 20% reduction in line  $Z_0$  resulted in as little as 3% increase in 3I0, it would result in a 20% increase in the reach of a ground distance element.

## **Bibliography**

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## **Biography**

David Beach received a BS degree in Electrical Engineering from California State University, Fresno in December of 1982. Since that time, David has become a Registered Professional Engineer, licensed in the states of California, Oregon, and Washington. David worked in the Consulting Engineering business until February 2005, when he joined Basler Electric Company as a Senior Application Engineer. In December 2006, David became a System Protection Engineer with Portland General Electric. David is a Senior Member of the IEEE, a member of the Industrial Applications Society and the Power Engineering Society of IEEE. David is also a member of the WECC Relay Work Group.