A New Approach for Automated Fault Location

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Outline

• Introduction
• New fault location method using voltage monitors on transmission system for all fault types
• Case studies
• Extension of the problem using voltage monitors on distribution system
• Case studies
• Conclusions and suggestions for future work
What Is a Fault and Its Impacts

• A fault is a short circuit caused by an internal or external element in a power system, such as lightning, tree, animal.

• It creates a voltage sag in the entire system and sometimes a complete line outage.

• The voltage sag can have severe negative impact in operation of sensitive loads; such as high-tech or data-center facilities.
Why is it Important to Quickly Estimate the Location of Transmission Faults?

Repair and determine the cause of a fault as a preventive measure, due to:

- Generation is being imported over long distances
- Transmission lines are becoming more congested
- Sustained faults have adverse economic impact as well as impact on system operation and reliability
- Increasing number of sensitive loads
Available Devices

- Digital fault recorders on transmission system
- Microprocessor relays at substations
- Power quality monitoring devices
- Smart meters with PQ data
## Digital Fault Recorder

![Voltage Sag](image)

<table>
<thead>
<tr>
<th>Channel</th>
<th>V (rms)</th>
<th>T1: 63.31</th>
<th>T2: 77.38</th>
<th>TD: 140.69</th>
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</thead>
<tbody>
<tr>
<td>MB1VA</td>
<td>79323</td>
<td>78096</td>
<td>1226.7</td>
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<tr>
<td>MB1VB</td>
<td>78935</td>
<td>82399</td>
<td>3464.3</td>
<td></td>
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<tr>
<td>MB1VC</td>
<td>77977</td>
<td>38800</td>
<td>-39177</td>
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<tr>
<td>MB1V0</td>
<td>692.83</td>
<td>52690</td>
<td>51997</td>
<td></td>
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<tr>
<td>AT1VGD</td>
<td>103.86</td>
<td>131.40</td>
<td>27.54</td>
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<tr>
<td>x15 900IA</td>
<td>151.94</td>
<td>750.19</td>
<td>598.25</td>
<td></td>
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<tr>
<td>x15 900IC</td>
<td>127.69</td>
<td>2625.0</td>
<td>2697.3</td>
<td></td>
</tr>
<tr>
<td>x12 900IN</td>
<td>108.12</td>
<td>3573.1</td>
<td>3465.0</td>
<td></td>
</tr>
</tbody>
</table>
Start of BG fault

Start of BCG

Start of BCAG

Prefault 80.51kV

33.22 kV 58.7 % sag

Relay Trigger 886.3 Amps
PQ Monitoring Devices
(12.5 kV, A-G; 80% sag, 5 cyc)
## Voltage Sags Due to a Fault
*(typical severe fault)*

<table>
<thead>
<tr>
<th>Bus #</th>
<th>Substation</th>
<th>Voltage (PU)</th>
<th>Bus #</th>
<th>Substation</th>
<th>Voltage (PU)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9200</td>
<td>GROVE</td>
<td>71.80%</td>
<td>9239</td>
<td>MAGPLANT</td>
<td>37.90%</td>
</tr>
<tr>
<td>9202</td>
<td>HAMILTON</td>
<td>25.70%</td>
<td>9243</td>
<td>NORTH</td>
<td>61.50%</td>
</tr>
<tr>
<td>9203</td>
<td>HAMILMB2</td>
<td>25.60%</td>
<td>9247</td>
<td>OAKHILL</td>
<td>67.60%</td>
</tr>
<tr>
<td>9204</td>
<td>HARRIS</td>
<td>75.30%</td>
<td>9251</td>
<td>ONION</td>
<td>78.40%</td>
</tr>
<tr>
<td>9212</td>
<td>HOLLYMB1</td>
<td>75.30%</td>
<td>9255</td>
<td>PATTON</td>
<td>67.20%</td>
</tr>
<tr>
<td>9213</td>
<td>HOLLYMB2</td>
<td>75.30%</td>
<td>9257</td>
<td>PEDERNAL</td>
<td>75.30%</td>
</tr>
<tr>
<td>9214</td>
<td>HOLLYMB3</td>
<td>75.30%</td>
<td>9259</td>
<td>PILOT</td>
<td>76.50%</td>
</tr>
<tr>
<td>9215</td>
<td>HOLLYMB4</td>
<td>75.30%</td>
<td>9260</td>
<td>RIVERPLS</td>
<td>35.40%</td>
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<tr>
<td>9216</td>
<td>SANDHILL</td>
<td>78.80%</td>
<td>9263</td>
<td>SALEMWLK</td>
<td>70.80%</td>
</tr>
<tr>
<td>9217</td>
<td>HOWARD</td>
<td>23.80%</td>
<td>9267</td>
<td>SLAUGTR</td>
<td>72.90%</td>
</tr>
<tr>
<td>9220</td>
<td>JETT</td>
<td>30.30%</td>
<td>9271</td>
<td>SPRINKLE</td>
<td>29.00%</td>
</tr>
<tr>
<td>9223</td>
<td>JOLLYVIL</td>
<td>37.00%</td>
<td>9275</td>
<td>STECK</td>
<td>28.00%</td>
</tr>
<tr>
<td>9227</td>
<td>KOENIG</td>
<td>50.30%</td>
<td>9279</td>
<td>SUMMITN</td>
<td>22.10%</td>
</tr>
<tr>
<td>9228</td>
<td>LAKESHOR</td>
<td>41.90%</td>
<td>9280</td>
<td>SUMMITS</td>
<td>22.10%</td>
</tr>
</tbody>
</table>
Existing Methodologies for Locating a Fault

Impedance method

- Distance to the fault is determined by dividing the measured reactance by the total reactance of the line multiplied by the line length.

Traveling wave method

- Distance to the fault is determined by the time difference between an incident wave approaching the fault and the corresponding wave reflected at the fault - Use of GPS time.
Existing Industry Practices for Fault Location

1. If an IED (DFR or microprocessor relays) is used on the faulted segment, then measured voltage and current waveform are easily (and sometimes automatically) converted to distance estimates using the impedance of the line segment.

2. When electromechanical relay are employed, estimation is by field inspection and/or manual short circuit simulations.

3. If there are false or sympathetic trips of other circuit breakers, the process reverts to field inspection and/or simulations.
Existing Industry Practices for Fault Location

• Most important current deficiency in determining fault location is **time**
  – Drive to substations
  – Remote communication- Failures of: comm. lines, sub. modems (due to fault), Ethernet problem
  – Too much data to look at; time to manually analyze collected data
  – Lack of expertise and needed resources for analysis
New Fault Location Method Using Transmission System Monitors

• The new procedure uses the system voltage and system impedance matrices with least-squared error minimization technique to estimate the fault location.

• The procedure was successfully tested on 15 actual faults to verify its validity for all fault types.

• The new procedure can take advantage of the existing data at no extra cost, and supplement the existing fault location procedure.
Existing vs. New Method

• Install detectors at every bus: Time + data + cost

• With the new method, we only need to have a few voltage monitors respond to the event to successfully locate the fault.

• Most utilities already have such monitors in their transmission system and many more in their distribution system.

• The new methodology shows how to use the existing equipment and data more intelligently.
Calculating System Impedance Matrix

• Every utility has system’s sequence data and system loadflow and short circuit cases, but no simple tool to get impedance matrix data

• Commercially available codes $15K-20K

• Free program- PCFLO

• Thevenin equivalent the rest of the surrounding systems.
Three-Phase Balanced Faults

Problem: a set of voltage sag measurements at metered buses m1, m2, m3, ... mn, Identify the bus at which the fault occurred.

Error function at each candidate bus k, for k = 1, 2,… n,

$$err_k^2 = \sum_{m=1}^{n} \left( |\Delta V_{m,meas}^+| - |\Delta V_{m,pred(k)}^+| \right)^2$$

$$|\Delta V_{m,meas}^+|$$ measured positive-sequence sag magnitude, in per unit, at metered bus m,

$$|\Delta V_{m,pred(k)}^+|$$ corresponding predicted positive-sequence sag magnitude.
Assuming pre-fault voltage magnitude of 1.0,

\[ |\Delta V_{m,\text{pred}(k)}^+| = 1.0 - |Z_{m,k}^+ I_k^+|, \quad (2.2) \]

\( I_k^+ \) is the unknown positive sequence fault current at candidate bus \( k \), in PU.

\[ |I_k^+|_{MAX} = \frac{1}{|Z_{k,k}^+|} \quad (2.3) \]

From (2.2), we obtain sag magnitude

\[ \Delta V_{m,\text{pred}(k)}^+ = 1.0 - |\Delta V_{m,\text{pred}(k)}^+| = |Z_{m,k}^+ I_k^+| \]
yields
\[ |I_k^+| = \frac{\sum_{m=1}^{n} |\Delta V_{m,meas}^+| |Z_{m,k}^+|}{\sum_{m=1}^{n} |Z_{m,k}^+|^2}, \] (2.6)

subject to upper bound,
\[ |I_k^+| \leq |I_{k,MAX}^+| = \frac{1}{|Z_{k,k}^+|}. \] (2.7)

The constraint eliminates “far away” buses from the list of likely candidates.

\[ err_k^2 = \sum_{m=1}^{n} \left( |\Delta V_{m,meas}^+| - |Z_{m,k}^+| |I_k^+| \right)^2. \] (2.4)

We do this for all buses and every bus has a best \( I_k \), but the bus that produces the smallest error is the winner, the likely candidate.

**Similar procedure for other fault types.**
The Austin Energy System

• 844,263 service area population
• 421 square miles of service area
• 2,383 MW system peak
• 2,934 MW generation capacity
• 608 miles of transmission lines
• 10,308 miles of OH and UG distribution lines
• 9 transmission substations
• 54 distribution substations
Case 1. 69 kV Phase-to-ground fault. 4.5 cycles. Automobile accident.
Case 3. 138 kV 3 Phase fault.
5 cycles. Substation insulator explosion.
Case 4. 138 kV 1 Phase-to-ground fault.  
5 cycles. Contact between buzzard and CKT 929
Case 6. 138 kV 2 Phase fault.
4 cycles. Ice, Galloping conductors
Case 7. 138 kV 2 Phase fault.
4 cycles. Ice, Galloping conductors
Case 15. 138 kV 1 Phase-to-ground fault.
4 cycles. Buzzard
Results – Case Summaries

• Out of 15 cases:
  – 7 estimated exact location with two meter data that had the deepest sag,
  – 5 additional with three meter data,
  – 1 additional with fourth meter data,
  – the remaining 2 cases estimated at one bus away from the actual near system boundary, and
  – 0 with fifth meter data.

• Overall, most of the times, two voltage monitors were enough, but three voltage monitors were sufficient to accurately estimate the fault location.
Extension of the Problem Formulation Using Voltage Monitors on Distribution System

- Takes advantage of the capabilities of microprocessor relays on distribution feeders (SEL relays).
- Use of symmetrical comp. and transformation matrix to transform voltage data to high side.
Transformer Phase Shift

• YY and Δ Δ Transformers Have No Phase Shift

• Three-Wire Connections (i.e., Δ and Ungrounded Y) Have No Zero Sequence Currents

• Zero Sequence Currents Can Flow on the Y Side of a Grounded-Y: Δ Transformer

• High-voltage side positive sequence voltages and currents in Y:Δ (and Δ:Y) transformers lead those on the low-voltage side by 30°

• High-voltage side negative sequence voltages and currents in Y:Δ (and Δ:Y) transformers lag those on the low-voltage side by 30°
Computing High-side Sequence Voltages

• Positive and negative sequences are calculated using the fundamental principals of transformer phase shift.

• Need to calculate $V_0$ component on the high side which is not observed on the low side of a delta-to-wye grounded transformer - estimating missing component.
## Case Studies

<table>
<thead>
<tr>
<th>Case 1</th>
<th>Estimate of Trans. side Voltage Using Distribution side Relay Data</th>
<th>Measured Transmission Relay Data</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mag</td>
<td>Angle</td>
</tr>
<tr>
<td>$V_a$</td>
<td>86.7</td>
<td>1.0</td>
</tr>
<tr>
<td>$V_b$</td>
<td>36.5</td>
<td>130.4</td>
</tr>
<tr>
<td>$V_c$</td>
<td>87.5</td>
<td>253.1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case 2</th>
<th>Estimate of Trans. side Voltage Using Distribution side Relay Data</th>
<th>Measured Transmission Relay Data</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mag</td>
<td>Angle</td>
</tr>
<tr>
<td>$V_a$</td>
<td>17.9</td>
<td>-4.3</td>
</tr>
<tr>
<td>$V_b$</td>
<td>92.5</td>
<td>147.9</td>
</tr>
<tr>
<td>$V_c$</td>
<td>95.6</td>
<td>243.6</td>
</tr>
</tbody>
</table>
Case 6. Using low-side data (previous Case 13)
Failure of HL-456 unit sub
Results

• Indeed, distribution-side voltage sag measurements can be used to pinpoint the location of transmission-side faults provided that transformer phase shift is properly handled.

• This conclusion is significant because there are many distribution-side monitors available, thus enhancing the accuracy of our predictions.
Conclusion and Possible Future Improvements

• Novel method of locating faults using voltage only was presented, backed with 15 cases for all fault types.

• Successfully cross over to distribution system and intelligent use of the large number of available devices.

• A set of guidelines for optimal siting of voltage only recorders in a system.

• Using a large set of voltage sag measurements to detect improperly modeled transmission elements and the impedance matrix.

• A method for locating the fault on a line rather than at a bus.
Questions?