Transmission Line Automated Relay Coordination Checking

Holistic Assessment of Protection Settings

Saman Alaeddini
Ashok Gopalakrishnan
Quanta Technology, USA

Paul I. Nyombi
Garret Sarkinen
Xcel Energy, USA

Minnesota Power Systems Conference
St. Paul, MN
November 10-12, 2015
Outline

- Motivation and benefits
- Procedure
- Case study with examples
- Conclusions
Motivation

Large scale protection review is needed for several reasons:

- Humans tend to make mistakes – identify and rectify settings errors before they actually manifest themselves as misoperations leading to system outages

- Industry practices have evolved over time

- Complexity of relays has dramatically increased in recent years
**Motivation**

Large scale protection review is needed for several reasons:

- Ensure consistency in setting policies
  - Protection schemes over entire system not routinely reviewed when settings philosophy changes are made

- Minimize risk of outaging more equipment than is absolutely necessary

- Incremental changes over time (system topology, load, generation, fault duties...)

© 2015 Quanta Technology & Xcel Energy
Benefits of Wide Area Protection Studies

- Increased confidence in the reliability of system protection and relay settings
- Benchmark against current industry-accepted practices
- Develop and enhance asset replacement strategies
Benefits of Wide Area Protection Studies

- Relay settings modeled with high degree of quality control

- Automation will help increase the capabilities and productivity of the relay engineers

- Comprehensive protection philosophy guide for the utility
Comprehensive Assessment of Protection Settings

3 Phase Process: Model, Study, Analyze
Comprehensive Assessment of Protection Settings

Phase 1: Model
- Power System (Lines, Transformers, Generation…)
- Primary Relays
- Backup Relays (local & remote)
- Pilot Schemes (POTT, DCB, PUTT, DTT)
- Breaker Failure (BF)
- Automatic Reclosing
- Current & Voltage Transformers
- Trip Logic
- Thermal Ratings

Any change in the system can initiate the entire process
Comprehensive Assessment of Protection Settings

Phase 2: Study

Standard & Guidelines
- Best practice guidelines
- Customer Specifications
- Industry Guidelines (IEEE)
- Standard Requirements (NERC)

Sensitivity & PRC-023 Study
Evaluates the setting of individual relay elements against the criteria used to select them

Coordination Study
Challenge the operation of all relays in a selected study area by applying a large number of fault types, fault locations, and contingencies
Phase 3: Analyze

Formatting Guideline
Provides input on the appearance of the report(s) to be created (i.e. Final PRC-023 Compliance Auditable Report).

Philosophy Guideline
Provides input on how to interpret the data, what to evaluate, how to evaluate it, and what constitutes a pass or fail when evaluating protective elements.

Modeling Guideline
Provides rules that are utilized when analyzing and interpreting the model.
Automated Coordination Studies

- Uncover and remove hidden sensitivity and coordination issues before they actually occur as relay misoperations

- Evaluate responses of protective relays working together as a system, rather than as simple pairs of relays with a primary – backup relationship

- Challenge the protection system with a large number of fault types, fault locations and system contingencies

- Relieve the protection engineer from having to run the studies himself or herself, and focus attention on problem solving
Automated Coordination Studies

- Defining study area per study line

  - **Number of levels of backup protection**: number of remote buses away from each terminal of a line on adjacent lines (1: one bus away, 2: two buses away)

  - **Number of levels of Mutual coupling included**: level of mutual coupling with a study line (1=immediate coupling, 2:coupled with the coupled lines)

- Study objectives:

  - **Misoperation**: Ensure that primary protection related to the study line can detect and clear a fault faster than fastest backup protection

  - **CTI Violation**: Check the available time intervals between the fastest primary and all backup protection are acceptable
Automated Coordination Studies

- Establish a “study line”

- Apply different fault types, at multiple locations
  - Fault types: SLG, L-L, TPH, DLG (bolted or resistive)
  - Fault locations: Close-In, 10%, 20%, 50%, 80%, 90%, Remote-end

- Check that primary protection operates as expected
  - Check redundant packages (Primary & Secondary) individually
Automated Coordination Studies

- Evaluate Coordination Time Intervals (CTIs) between primary and backup elements at each breaker operation

- Flag CTIs that do not meet minimum coordination interval requirements

- Determine if any of back-up elements may operate ahead of primary protection (misoperation)

- Continue until fault clears

- Move on to the next fault
Automated Coordination Studies - Example

- Four bolted faults SLG, LTL, DLG and TPH,
- Four resistive faults 1 & 5 ohms SLG & DLG
- Five fault locations
- Assume five local sources including mutual coupling
- Assume five remote sources
- Two protection packages, A and B
- No. of simulations = 8 x 5 x 11 x 2 = 880

1 System Normal
-10 Source outages

-2 Packages
Automated Coordination Studies

Bulk Power System

Package A in Service (Package B out of service)
- Pilot Out of Service
  - Normal Study
  - TPH
  - SLG
  - SLG-RF
- Pilot in Service
  - Normal Study
  - TPH
  - SLG
  - SLG-RF

Package B in Service (Package A out of service)
- Pilot Out of Service
  - Normal Study
  - TPH
  - SLG
  - SLG-RF
- Pilot in Service
  - Normal Study
  - TPH
  - SLG
  - SLG-RF

System Contingency Studies
**Coordination Study Post Processing**

- Typical study output documents the details of various relay operations.

<table>
<thead>
<tr>
<th>No.</th>
<th>Situation/Outages</th>
<th>Fault Type</th>
<th>Fault Location</th>
<th>Time(cyc) Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>38</td>
<td>Normal</td>
<td>SLG Remote Close-in: on LN 345_39 to North_West 2.90 CTI VIOLATION</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Event:** 1 at 2.40 cycles; 0.040 seconds

<table>
<thead>
<tr>
<th>Substation</th>
<th>LZOP Name</th>
<th>TYPE</th>
<th>Backup</th>
<th>Time</th>
<th>Brkr</th>
<th>Total</th>
<th>Avail</th>
<th>Operation Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>North_West</td>
<td>LINE</td>
<td>PRIMARY</td>
<td>0.44</td>
<td>2.00</td>
<td>2.44</td>
<td>N/A</td>
<td></td>
<td>NORMAL OPERATION</td>
</tr>
<tr>
<td>Element: 9745</td>
<td>DIST &quot;Z1G&quot;</td>
<td>&quot;1&quot;; (SEL-421); Contact Logic Code: 21G1_A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Element: 9745</td>
<td>AUX &quot;67G1&quot;; (SEL-421); Contact Logic Code: 67NI_A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Element: 9747</td>
<td>AUX &quot;TRIP&quot;; (PILOT_WIZARD); Contact Logic Code: POTT_TRIA</td>
<td>Supervisor: 9745 DIST &quot;Z2G&quot;</td>
<td>&quot;2&quot;; (SEL-421);</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South_East</td>
<td>LINE</td>
<td>PRIMARY</td>
<td>0.94</td>
<td>2.00</td>
<td>2.94</td>
<td>N/A</td>
<td></td>
<td>NORMAL OPERATION</td>
</tr>
<tr>
<td>Element: 9781</td>
<td>AUX &quot;TRIP&quot;; (PILOT_WIZARD); Contact Logic Code: POTT_TRIA</td>
<td>Supervisor: 9779 DIST &quot;Z2G&quot;</td>
<td>&quot;2&quot;; (SEL-421);</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North</td>
<td>LINE</td>
<td>BACKUP</td>
<td>1.44</td>
<td>2.00</td>
<td>3.44</td>
<td>-1.00</td>
<td>CTI VIOLATION</td>
<td></td>
</tr>
<tr>
<td>Element: 9600</td>
<td>DIST &quot;Z1G&quot;</td>
<td>&quot;1&quot;; (SEL-421); Contact Logic Code: 21G1_A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North_West</td>
<td>LINE</td>
<td>BACKUP</td>
<td>15.00</td>
<td>3.00</td>
<td>18.00</td>
<td>12.56</td>
<td>CTI VIOLATION</td>
<td></td>
</tr>
<tr>
<td>Element: 7283</td>
<td>TOC &quot;51N&quot;; (REL512); Contact Logic Code: 67MT_B</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South</td>
<td>LINE</td>
<td>BACKUP</td>
<td>22.00</td>
<td>2.00</td>
<td>24.00</td>
<td>19.56</td>
<td>PREDICTED</td>
<td></td>
</tr>
<tr>
<td>Element: 9892</td>
<td>TIMER &quot;Z4GD&quot;</td>
<td>&quot;1&quot;; (SEL-421); Contact Logic Code: 21G2T_A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Element: 9893</td>
<td>TIMER &quot;T23G&quot;</td>
<td>&quot;1&quot;; (F442); Contact Logic Code: 21G2T_B</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Xcel Energy is performing numerous system upgrades to its existing transformer and transmission lines

Several transformer and transmission line additions are also required for Wind Generation outlets

CAPX2020 project is adding nearly 800 miles of transmission (most of which 345kV) crisscrossing the state of Minnesota.

- More info can be found at http://www.capx2020.com

This expansion can create a significant change in system fault currents creating possible over tripping of instantaneous elements and mis-coordination of time delay tripping elements

Protection engineers performing relay settings on all the new and upgraded equipment can be managed, but how about coordination of all other transmission in the area?

- Huge amount of human resources is required to perform new relay settings as well as to validate coordination on all adjacent transmission relays
**Case Study - Project Background**

- Xcel Energy yearns for an approach to automate coordination verification for the current CAPX2020 project and in the future
  - Ability to prove relays coordinate with various system changes over time
- Study focus was on the NERC Bulk Electric System (BES) transmission lines (over 900 transmission lines validating coordination of protection schemes excluding pilot relaying schemes – worst case scenario)

<table>
<thead>
<tr>
<th></th>
<th>kV</th>
<th>Line Count</th>
<th>Region</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NSP Region</strong></td>
<td>500</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>345</td>
<td>45</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>230</td>
<td>10</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>161</td>
<td>36</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>115</td>
<td>225</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>PSCo Region</strong></td>
<td>345</td>
<td>12</td>
<td>318</td>
<td>910</td>
</tr>
<tr>
<td></td>
<td>230</td>
<td>127</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>138</td>
<td>4</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>115</td>
<td>119</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>SPS Region</strong></td>
<td>345</td>
<td>8</td>
<td>330</td>
<td></td>
</tr>
<tr>
<td></td>
<td>230</td>
<td>75</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>115</td>
<td>247</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Case Study - Project Findings

- **579 Substation reviewed**
  - 1,755 Terminals
  - 3,204 Protective Relays
  - 16,816 Protective Elements

- All elements assigned a calculated risk number using the following criteria:
  - Misoperation and the type of fault scenario
  - CTI violation, number of cycles, and the type of fault scenario
  - kV level of the associated line

**The most common element with risk:** Ground Timed Overcurrent

![Risk Distribution Chart]

- **High** 30%
- **Medium** 10%
- **Low** 60%
Case Study - Project Findings

- Majority of coordination problems identified are categorized by the following:
  - Fault detector compromise for N-1 contingency
  - Unique N-1 Contingency (Ground Distance Element Compromised due to Mutual Coupling Effects)
  - Desensitization of Tripping Elements due to System Changes
Example 1 – Fault Detector Desensitization

- Fault Study:
  - Three phase faults are applied on the Stanford to Provo line
  - A pair of protection packages, used at both ends of the target line, operate correctly for system normal
  - One protection package, at Stanford, fails for N-1 contingency when the strongest fault current source, the Malibu line is outaged due to a fault detector setting
  - Mis-operation occurs at Raffles; 115 kV lines’ overreaching zones to Stanford see the faults and trip
Example 1 – Fault Detector Desensitization

- Study Line: a BES 345 kV, Stanford to Provo line
  - Local and Remote line ends use 2 protection packages (primary and secondary)
Example 1 – Fault Detector Desensitization

System Wide Area Coordination Study

- **Malibu**: N-1 Contingency (Outaged Line)
- **Stanford**:
  - Provo Terminal operated in 2.7 cycles (faulted line)
- **Raffles’ line#1 Z2P** picks up and starts timing
- **Raffles’ line#2 Z2P** doesn’t see the fault yet
- **Stanford Terminal** fails to operate (faulted line)

Three Phase Fault
Example 1 – Fault Detector Desensitization

System Wide Area Coordination Study

N-1 Contingency (Outaged Line)

Stanford Terminal fails to operate (faulted line)

Raffles’ line#1 Z2P operates in 18.2 cycles

Provo Terminal operated in 2.7 cycles (faulted line)

Raffles’ line#2 Z2P now picks up, starts timing
Example 1 – Fault Detector Desensitization

System Wide Area Coordination Study

Raffles’ line#1 Z2P operates in 18.2 cycles

Stanford Terminal fails to operate (faulted line)

N-1 Contingency (Outaged Line)

Provo Terminal operated in 2.7 cycles (faulted line)

Raffles’ line#2 Z2P operates in 36.2 cycles
Example 1 – Fault Detector Desensitization

Provo’s Phase Distance Elements – Apparent Impedance Plot

Substation: STANFORD
LZOB: “Stanford_Provo_345kV”
Line Impedance: 21.174 P. Ohms @ 84.73 deg.

Provo_21S_345kV
1. Distance 21P1
CTR 400.0 @0 VTR 3000.0 @0 CTR/VTR 0.133
Forward Reach 18.00 P. Ohms @ 84.7 deg.

2. Distance 21P2
CTR 400.0 @0 VTR 3000.0 @0 CTR/VTR 0.133
Forward Reach 31.72 P. Ohms @ 84.7 deg.

Fault: A
Midline THREE PHASE fault on line “Stanford_345 kV” to “Provo_345 kV”
Malibu to Stanford 345 kV line out

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10.59 84.73</td>
<td>infinite</td>
<td>DELTA-V/DELTA-I A-B 12.30 @ -3.5</td>
</tr>
<tr>
<td>2</td>
<td>10.59 84.73</td>
<td>infinite</td>
<td>DELTA-V/DELTA-I A-B 12.30 @ -3.5</td>
</tr>
</tbody>
</table>
Conclusion:

- Typical Distance Elements Logic

- Overcurrent relay elements may be used as a Fault Detector to supervise distance trip logic (wired externally)

- Recognizing Trip Logic may be Z1/2 & 50P

- Plotting the apparent impedance of distance elements for fault currents below FD pickup may not block mho element operation even if the TRIP logic isn’t asserted
Example 1 – Fault Detector Desensitization

Conclusion:

- Supervising FDs don’t see the fault because of reduced current with the removal of the strongest fault current source behind the Stanford relays.
- By just plotting the distance elements, the problem is not apparent – mho elements show proper operation when plotted graphically; it becomes all apparent with system wide coordination studies that involve all supervisory and tripping elements.
- Remedy is to lower the fault current pickup to accommodate the worst (least fault current) acceptable operation contingency.
Example 2 – Mutual Coupling Effects

- Fault Study:
  - Single line to ground bus and close-in faults are applied at St. Barts and on 345 kV lines emanating from St. Barts substation.
  - Protection packages at Nevis line operate correctly (block operation) for system normal, potentially hiding an existent problem.
  - One protection package, at Nevis, fails for N-1 contingency, with the strongest zero seq. current source at the local substation, St. Bart’s GSU, outaged.
  - Mis-operation occurs at Nevis; induced zero-sequence currents on the Nevis line from the adjacent line (St. Barts to Caves) cause zone 1 ground distance elements at Nevis to overreach.
**Example 2 – Mutual Coupling Effects**

- Study Line: a BES 345 kV, St. Barts to Caves line

- 14 mi. mutual coupling between target line and St. Barts to Nevis line (18% of Nevis line)
Example 2 – Mutual Coupling Effects

N-1 Contingency (Outaged GSU)

Faulted line

St. Barts Terminal operates in 3 cycles

Caves Terminal starts timing via zone 2

14 mi. mutual coupling between target line and St. Barts to Nevis line (18% of Nevis line)

Nevis Terminal incorrectly operates in 4.4 cycles via Z1G
Example 2 – Mutual Coupling Effects

N-1 Contingency (Outaged GSU)

14 mi. mutual coupling between target line and St. Barts to Nevis line (18% of Nevis line)

Faulted line

St. Barts Terminal operates in 3 cycles

Caves Terminal clears fault after 17.2 cycles

Nevis Terminal incorrectly operates in 4.4 cycles due to Z1G
Example 2 – Mutual Coupling Effects

Nevis’s Zone 1 Ground Distance Element – Apparent Impedance Plot

 subst: Nevis
 LZONE: “St. Barts_Caves_345 kV”
 Line Impedance: 50.635 P. Ohms @ 83.93 deg.

 St. Barts_21S_345 kV:
 1. Distance 1G
 CTR 400.0 O-160 VTR 3000.0 O-0 CTR/VTR 0.133
 Unit in: MHO

 Forward Reach: 42.45 P. Ohms @ 84.8 deg.

Fault: A
Close-in SINGLE LINE GROUND fault on line “St. Barts_345 kV” to “Caves 345 kV”

Curve: Apparent Operating S.I.R. (+ seq)
 Impedance Time Source/total line
[Mag] [Deg] [Cycles] [Mag] [Deg]

Fault: B
Close-in SINGLE LINE GROUND fault on line “St. Barts_345 kV” to “Caves 345 kV”
St. Barts_345/115 kV Xfer out

Fault: C
Close-in SINGLE LINE GROUND fault on line “St. Barts_345 kV” to “Caves 345 kV”
St. Barts_345/20 kV GUS Xfer out
Example 2 – Mutual Coupling Effects

Conclusion:

- With the system normal, bus or close-in SLG at St. Barts, potential mis-operation is masked by the strong zero-sequence current source – St. Bart’s GSU

- When local ground zero-sequence current sources, at St. Barts are outaged, one at a time, Nevis’s Z1G apparent impedance steadily increases due zero-sequence current re-distribution

- This leads to an increase in the zero-sequence current induced on the St. Barts to Nevis line by St. Barts to Caves

- Remedy is to pull back Nevis’ Z1G reach so it doesn’t overreach for the worst case possible system operational contingency
Example 3 – Other issues revealed by studies

Tripping elements falling out of desired range due to system changes

- Constant transmission rebuilds, decommissioning and re-routing of lines affect system impedances and fault current redistribution
- Some effects of the system changes may not be apparent to the relay engineer especially if they aren’t the immediate vicinity of the affected equipment
- Periodic running of system wide area coordination studies can help catch such potential mis-operations
Example 3 – Other issues revealed by studies

Inadvertent default settings in the relays

- Default and potentially, problematic settings, can get inadvertently left in the relay.

- Running sensitivity and coordination checks on the studied lines catches these before settings are sent out to the field. An example of this is not setting the series compensation to “off” when not required. A default value gets used in the relay computation.

- Periodic running of system wide area coordination studies can help catch such potential mis-operations that get missed at the time of relay setting.
Partial Statistics of the analyzed data

- Fifty four 345 kV Xcel Energy owned/partially-owned lines were studied
- 13 lines passed the studies with no major issues
- 41 lines either had CTI violations or misoperations or both – only 26% of the flagged violations required immediate addressing
Conclusion

- Automation is the key to performing a successful audit of the protection system
- Protection engineer is relieved from the tedium of manually applying contingencies, and faults and focuses their attention on settings issues uncovered
- Automation creates a document trail that can be used for auditing purposes
- And lastly, as the system changes it becomes very easy to let the computer to run additional studies to uncover coordination issues
- 345 kV data has been analyzed to identify mitigating action. Analysis of data from other voltages is ongoing
Acknowledgment

- Saman Alaeddini, Ashok Gopalakrishnan, Juergen Holbach, Farid Katiraei, Quanta Technology LLC
- Garret Sarkinen, Adi Mulawarman, Garret Kauer, Derlin Campbell, Shannon Bellinghausen, Paul Nyombi, Xcel Energy
- Paul McGuire, Electrocon International, Inc.

References

- “A Comprehensive Analysis of Wide Area Protection Coordination versus Conventional Methods for Protection Coordination of Transmission Lines”, presented at Georgia Tech Protective Relaying Conference, April 2010
Questions?

SAlaeddini@quanta-technology.com  (416) 825-6009
Paul.Nyombi@xcelenergy.com  (612) 330-1937