Critical Issues In Protective Relaying

Protective Relay Engineering Perspectives From 24 Countries

NEWTON-EVANS RESEARCH COMPANY

Table of Contents

Introduction (Overview)

One theme that emerges from the varying responses is that there is no particular “right” way or “wrong” way to go about designing and implementing a particular relay scheme. Some utilities design schemes in a certain way, while others do it another way. What our project manager labels “Philosophy of Engineering” is evident in this study, especially in the choices made by P&C engineers as they apply relays to their systems.

This report includes more respondent comments than any previous relay survey conducted by Newton-Evans. We encourage you to read through these list compilations, as there is a wealth of information contained therein. What is a major issue for one engineer is not even a concern for another engineer.

As one example of utility diversity, it is fascinating to see in **Section D: Strategy/Policy Issues** the variety of ways Utilities are structured to handle the responsibilities of their Relay Organization, as well as to review the tactics used to attract and retain the next generation of relay engineers. Some Utilities have extensive training programs for young talent, while many do nothing or do not even recognize it as a potential problem.

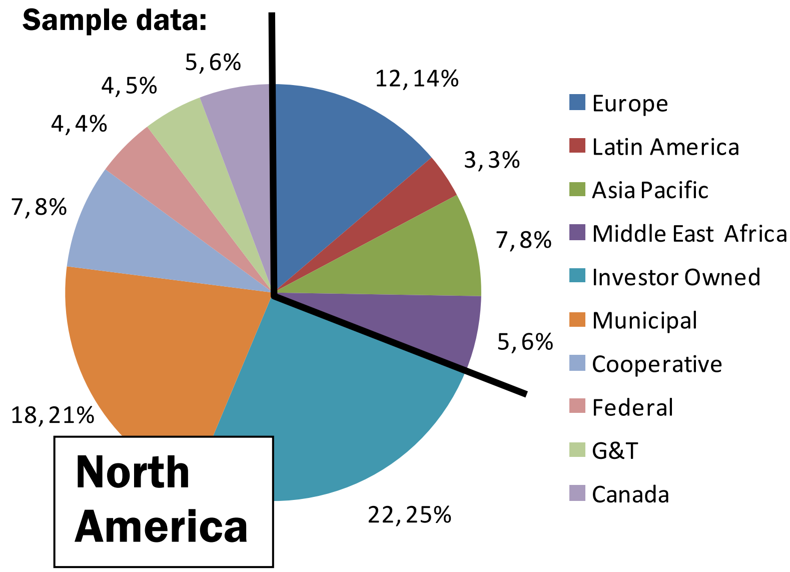
A few participants were pleased that this survey was unlike the typical P&C research to which many have grown accustomed. The questions asked in this survey cover a wide range of issues that relay engineers deal with on a day-to-day basis.

This report is not an “overview” nor is it a typical “Executive Summary.” This Newton-Evans *Protective Relay Engineering Perspectives* report is an in-depth study of topics currently on the minds of Protection & Control professionals throughout the world. Consequently, Newton-Evans trusts that the extensive comments and detailed charts will yield valuable insights in addition to providing useful information.

A total of 87 individual utility P&C personnel and systems planning officials responded to this questionnaire. Many of the survey questions were definitive choice, i.e. “yes/no,” or “pick only one of the following.” However, a few questions instructed respondents to “check all that apply.” Pie charts represent exclusive choice questions while bar charts represent questions where multiple answers were allowed (for example, “Which of the following criteria do you use…”)

Total Number of Respondents:		87
Total Number of Countries:		24
INTERNATIONAL		
	1 Europe	12
	2 Latin America	3
	3 Asia Pacific	7
	4 Middle East Africa	5
US		
	1 Investor Owned	22
	2 Municipal	18
	3 Cooperative	7
	4 Federal	4
	5 G&T	4
CANADA	Canada	5

Sample data:



Questionnaire

EQUIPMENT / DEVICE – related issues

1. What criteria do you use for replacing older *electromechanical* and *solid state* relays? Check all that apply.
☐ Replace upon failure ☐ Replace by age, after [ ]years
☐ Replace those serving critical functions ☐ Replace specific relay types based on overall maintenance history
☐ Replace as part of area capital improvements/new construction in nearby system
☐ Other (specify): [ ]

2. Does your utility use a redundant bay control unit? ☐ Yes ☐ No
If Yes, how are they fed/routed:
☐ TC#2 ☐ DCLC#2 ☐ Parallel ☐ Other: [ ]

3A. Some insulated conductors designed for use overhead in heavily wooded areas (or where insulation is of value) create a concern regarding detection of a fallen aerial conductor since the insulation may make fault resistance exceptionally high. Does your utility specify additional relay protection for circuits with covered aerial conductors?
For MV (≤ 30 kV) circuits: ☐ Yes ☐ No ☐ Do not use covered conductors at this voltage level
For HV (> 30kV) circuits: ☐ Yes ☐ No ☐ Do not use covered conductors at this voltage level

3B. If you answered yes for either of the above, please specify measuring principle used. Check all that apply.
(Medium Voltage)
☐ Negative phase sequence voltage ☐ Voltage controlled overcurrent ☐ Distance ☐ Transient measuring
☐ Harmonic ☐ Other: [ ]
(High Voltage)
☐ Negative phase sequence voltage ☐ Voltage controlled overcurrent ☐ Distance ☐ Transient measuring
☐ Harmonic ☐ Other: [ ]

4. Have you expanded disturbance monitoring in your protection system with the implementation of GPS clocks or other devices?
☐ No ☐ Yes, with GPS clocks ☐ Yes, with other devices: specify: [ ]

5. Do you use communication processors to consolidate relay communications for SCADA?
☐ Yes ☐ No Comment: [ ]

6. What types of transformer protection system devices do you use, and for what function? Check all that apply.
☐ Do not use transformer protection system devices
☐ Transformer pressure relief → ☐ Trip ☐ Alarm
☐ Bucholtz device → ☐ Trip ☐ Alarm
☐ Transformer temperature stages → ☐ Trip ☐ Alarm
☐ Fault pressure (sudden pressure) relays → ☐ Trip ☐ Alarm
☐ Other (specify below) → ☐ Trip ☐ Alarm

7. Communications problems may arise as a result of integrating multiple IEDs from various vendors. Have you moved to one vendor to reduce those problems?
☐ Yes ☐ No ☐ Not yet, but plan to Comment: [ ]

If you have *not* moved to one vendor, how are you addressing those potential issues mentioned in question 7?
Please place comments below:

8A. Does your Utility apply optical sensing arc flash protection to switchgear ≤ 30kV? ☐ Yes ☐ No
8B. If yes, does this include retrofitting to legacy switchgear? ☐ Yes ☐ No
9A. Does your Utility apply optical sensing arc flash protection to switchgear > 30kV? ☐ Yes ☐ No
9B. If yes, does this include retrofitting to legacy switchgear? ☐ Yes ☐ No

TRIPPING / CONTROL – related questions

1. Does your utility have any concern about output contacts (lower interrupting amp rating) of digital relays tripping breakers vs. older higher rated electromechanical relay contacts?
☐ Yes, major concern ☐ Yes, some concern ☐ No concern at all Comment: [ ]

Questionnaire

2. How do you monitor/plan to monitor your systems to make sure that under faulted conditions the breaker, lockout, or auxiliary relay will trip?

☐ Trip, or lockout coil monitoring and alarming back to a central monitored location. Approximate percentage in service for breakers and lockouts: [ ]%

☐ Physical red or white light monitoring circuit with visual inspection. Approximate percentage in service for breakers and lockouts: [ ]%

☐ Auxiliary relay monitoring circuit with remote alarming to a central monitored location. Approximate percentage in service for auxiliary relays: [ ]%

☐ Auxiliary relay monitoring with only local alarming. Approximate percentage in service for auxiliary relays: [ ]%

3. Do you use a fiber interface between RTU and relays? ☐ Yes ☐ No

If Yes, at what substation voltage? [ ]kV anything at [ ] kV and above

4. Some utilities are moving away from the "old way" of interfacing RTUs and Relays (using a pair of wires per I/O point) and now use the serial interface available on most modern relays. There is a concern that the "old fashioned" input may still be needed to detect the Protection Not Healthy alarm (from the Relay's hardware watchdog) so as not to purely rely on monitoring the serial link to the Relay. How does your Utility handle this issue?

☐ We use only the newer serial interface ☐ We use only the "old way" of interfacing

☐ We back-up the serial interface the "old way"

Comment: [ ]

5. Has the newer serial interface at any time failed to detect the Protection Not Healthy alarm?

☐ No, never ☐ Yes, infrequently ☐ Yes, several times

6. Would you consider applying GOOSE based tripping to replace the copper wire connection to the circuit breaker trip coil?

☐ Yes ☐ Depends on application ☐ No

*NOTE: If you do not use or have no plans to use IEC 61850, proceed to next section: **Settings/Analysis***

7. Relays can mis-operate / fail to trip for various reasons. With the adoption of IEC 61850, how can the technician visually and confidently find and test part of the scheme without opening the trip links? (i.e. Fiber only scheme with no copper trip links and one device on the bus has a partial failure that latches a trip or similar malfunction. There may no longer be the alternative of taking part of a scheme out of service to test unless the whole scheme was originally designed for removing the whole relay.) Please place comments below:

8. What has your experience been with the implementation of IEC 61850 in terms of performance of your protection schemes in general but more importantly GOOSE based interlocking within the substation?

☐ Never had a bad experience ☐ One negative experience ☐ Multiple negative experiences

☐ Does not apply to our relaying/protection scheme ☐ Other (please specify below):

9. If your utility has already implemented/plans to implement IEC 61850, are you still using/planning to use conventional wiring for interlocking purposes (arranging the control of equipment such that operation of one piece of equipment is dependent on another), or are you relying/planning to rely on IEC 61850 communication based software interlocking?

☐ Using/plan to use conventional wiring ☐ Relying/planning to rely on IEC 61850 communication based software

SETTINGS / ANALYSIS - related issues

1. How do you document/display the complex relay logic in your construction packages?

☐ Equation ☐ Logic diagram ☐ Boolean tables ☐ Other (please specify): [ ]

2. How do you manage digital relay firmware upgrades for installed relays?

☐ Freeze per relay application ☐ Upgrade every time ☐ Selectively by [ ]

3. Do you track firmware versions in a database? ☐ Yes ☐ No

4A. Do you track setting file versions in a database? ☐ Yes ☐ No

4B. How are the setting files referenced?

☐ Relay groups ☐ individual relay type ☐ functional scheme ☐ zone of protection

5A. How many relay profiles (i.e. a settings group; the programmatic instructions that the relay uses to issue commands) do you have in your standard distribution protection relay? Number: [ ]

5B. What are the different functions of each profile?

6. Do you use event report analysis to check / adjust relaying scheme or coordination?
☐ Yes ☐ No Comment: [ ]

7. In >110 kV substations, do you allow remotely made setting changes? ☐ Yes ☐ No (Go to Question #8)
If Yes, in what situations do you do so without local verification testing?

If Yes, how do you avoid human error? Check all that apply.
☐ Limited number of remote users ☐ Multiple passwords ☐ Settings comparison program before/after
☐ Other (specify): [ ]

8. In lieu of a formal comparative study, please briefly comment on system analysis and relay setting software (ASPEN, CAPE, CYME, DIgSILENT, et al).

STRATEGY / POLICY ISSUES

1. What strategy do you follow for improving the reliability and security of busbar protection? Please place comments below:

2. Given the global dearth of power system engineers, please describe what your utility is doing to attract, develop, and train new relay and protection engineers? Please place comments below:

3. With regard to the following relay-related activities, please check what you conduct in-house and where you require external assistance.

	In-house	Require External Assistance
Setting studies	☐	☐
Commissioning	☐	☐
Conceptual design	☐	☐
Detailed design	☐	☐
Turnkey supply of protective relay system	☐	☐
Panel fabrication	☐	☐
Installation	☐	☐
Maintenance	☐	☐
Testing	☐	☐
Training	☐	☐
Relay renovation and upgrade	☐	☐
Other: [ ]	☐	☐

4A. In light of the ongoing convergence of technologies in the areas of protection, metering, and control, as you integrate communication technology into the relay domain, how is your Utility structured?
☐ One organization responsible for all (with separate job functions)
☐ Separate IT group doing communications in support of relay applications
☐ Other (specify): [ ]

4B. Please indicate which organization is responsible for:
Communication Equipment Design: ____________________
Communication Equipment Purchasing: ____________________
Communication Equipment Commissioning/Initial Testing: ____________________
Communication Equipment Maintenance Testing: ____________________

5A. Has your utility's original 2009 Relay Budget:
☐ Held steady ☐ Been cut by about [ ]% ☐ Increased by about [ ]%

5B. What is the outlook for your 2010 Relay Budget?
☐ Hold steady as planned earlier ☐ To be cut by about [ ]% ☐ To increase by about [ ]%

Questionnaire

TESTING / MAINTENANCE

1. Not including test switches used to provide CT, PT, and trip isolation during testing, does your Utility use additional control handle, multi-position switches to disable system "parts"? (For example, a 3-position test switch to (1) disable communications channel only, (2) disable channel and relay outputs, (3) leave both channel and relay operational ☐ Yes ☐ No

If Yes, specify type: [ ]

2. Does your Utility use time based, condition based, or performance based testing of lockout relays or auxiliary relays used for breaker tripping?

☐ Time based (Specify interval): ______
☐ Condition based
☐ Performance based → Minimum sample size per device: ______
☐ Other (specify): ______

3. Does your Utility use process based or condition based maintenance for your protection system?

☐ Process based ☐ Condition based

4. Have you *extended* or *reduced* your relay testing / maintenance interval due the additional requirements created by NERC (or government regulatory) requirements?

☐ Extended ☐ Reduced ☐ No change Comment: [ ]

5A. Do you include transformer sudden pressure relays in your normal testing cycles? ☐ Yes ☐ No

5B. If Yes, what process do you use to test the sudden pressure devices? Describe below:

Miscellaneous Questions

1A. Do you use localized data gathering at substations with automated logic to operate local station equipment?

☐ Yes ☐ No

1B. Do you use a localized data bank within the substation that is remotely accessed for analysis and operator response?

☐ Yes ☐ No

1C. Do you download all the data from the substation to a central (corporate) server and then remotely access that for analysis and operator response? ☐ Yes ☐ No

2. Do you use pilot / communications-assisted relaying for distribution?

☐ Yes ☐ No ☐ No, but plan to by YE [ ]

Comment: ______

3. Has your Utility initiated negative sequence protection on radial distribution systems?

☐ Yes ☐ No ☐ No, but plan to by YE [ ]

4. Approximately what percentage of your digital relays are connected to an HMI, DCS, EMS, or SCADA monitoring system?

[ ] %

5. What is your experience with capacitive discharge of auxiliary cable circuitry causing the mis-operation of auxiliary relays or opto-inputs of numerical relays during a station battery earth fault condition?

☐ Never had a bad experience ☐ One negative experience ☐ Multiple negative experiences
☐ Does not apply to our relaying/protection scheme
☐ Other (specify below):

6. Beyond the use of Sensitive Earth Fault Detection for high impedance faults and accidents due to involuntary contact with live conductors, can you describe/provide other protection schemes for this issue? Please place comments below:

7A. Do you use multiple combinations of relay trip outputs to determine a trip condition (aka Voting Scheme) ?

Parallel paths (OR gate) → ☐ Yes ☐ No
Serial paths (AND gate) → ☐ Yes ☐ No
Mixed → ☐ Yes ☐ No

7B. For what reasons do you use such voting schemes? Please place comments below:

8. Other than when used for relay calculations, do you use any voltage element conditions in digital relays to aid relaying logic?
☐ Yes ☐ No Comment: [ ]

VENDOR / MANUFACTURER – related issues

1. Our Utility is in the process of introducing remote access to protective relays, primarily for interrogation purposes. We have a combination of Siemens, ABB, and Areva relays on our system. In your opinion, what communications protocol would you use? Please place comments below:

2. What strategy do you use to overcome the problems created by the mixture of vendors, tools, generations, and interfaces? Please place comments below:

3. Sometimes problems arise communicating with a relay when the OEM supplies a newer version of software to replace the old. Does your vendor provide support/assistance for changing the relay's version of software ?
☐ Yes, as required ☐ Yes, for an additional fee ☐ Yes, as part of purchase ☐ No

DISTRIBUTED GENERATION

1. The most common anti-islanding protection applied to embedded generators are typically rate of change of frequency (ROCOF), voltage vector shift, reverse power, neutral voltage displacement, etc. Does your Utility use other / new anti-islanding protections?
☐ Yes ☐ No Comment: [ ]

If you do not use ROCOF, proceed to Question #5

2. Have you been successful with the application of ROCOF protection for anti-islanding purposes?
☐ Yes ☐ No Comment: [ ]

3. In your experience, how repeatable is ROCOF protection?
☐ Never had a bad experience ☐ One negative experience ☐ Multiple negative experiences
☐ Other (specify): [ ]

4. How do you typically set your ROCOF function?
☐ Pick-up: [ ] ☐ Time delay: [ ]
Comment:

5. How do you protect embedded generators? Do you have the solution available to allow small distributed generation sites to safely connect to your utility network? ☐ No ☐ Yes (please describe):

6. What limitations do you impose on embedded generators in terms of being able to handle voltage and frequency fluctuations? Describe:

GENERATOR - related questions ☐ **←does not apply to our situation**

1. Do you test the response of relays used to protect your generator and equipment directly connected to your generator (e.g. transformer, station service, …) for underfrequency condition as experienced during stopping start-up of the generator?
☐ Yes ☐ No

2. Do you test the response of relays used to protect your generator and equipment directly connected to your generator (e.g. transformer, station service, …) for large over frequency (up to 200%) following tripping (of the generator breaker or tripping of the connecting lines) at 100% power production? ☐ Yes ☐ No

3. Do you use encryption for internal fiber communications when there is no access from outside your generation station?
☐ Yes ☐ No

Thank You For Your Help In This Research Effort