

# Grid-wide area protection settings analysis using protection settings evaluation tool

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eISSN 2051-3305

Received on 4th May 2018

Accepted on 23rd May 2018

E-First on 10th September 2018

doi: 10.1049/joe.2018.0244

www.ietdl.org

**Abstract:** This study sets out requirements for a tool to automatically evaluate protection relay coordination and assess, track, and visualise protection coordination results for large grid areas. The tool requirements include the selection process for which fault types, fault locations, contingencies, and generation dispatch should be studied, how the relay performance could be assessed, and how the large datasets produced by such analysis could be stored and visualised. Using these requirements, add-on tools were developed for two popular commercial short-circuit analysis programmes and tested and validated using network models from a number of real transmission and distribution grids.

## 1 Introduction

The protection relays applied to transmission and distribution grids are configured based on the known state of the grid at the time when the settings were designed and, potentially, known future states of the grid. It is generally not practical to study every possible grid operating state or every possible grid change (new lines, transformers, generators etc.) and develop a protection relay configuration which offers optimal performance in every possible eventuality. Furthermore, while the commissioning of a new line or transformer may initiate a business process to review protection coordination, the de-commissioning, moth-balling, or other change in generator running order may not despite it potentially having significant impact of protection performance.

Changes in short-circuit level and change in network impedance can impact overcurrent and impedance protection relay performance and coordination. Such changes may result in relays misoperating or failing to operate in response to faults on the grid. In the USA, there is a protection misoperation associated with ~10% of grid faults [1]. Of that 10%, approximately one-third of the misoperations are due to settings of logic design issues. If the process of assessing protection settings can be automated and a process put in place to actively mitigate the high-risk protection setting issues then at least some if not a large proportion of these misoperations may be avoided. This could present a significant increase in grid reliability.

The following sections will discuss some of the high-level considerations for performing protection coordination studies and sets out the capabilities that any automated analysis tool may require. While such an automated tool would provide greatest value when all protection relays are modelled in a short-circuit analysis tool, it can also provide value when only a subset of these relays are modelled. If the tool is coupled with a method for tracking results and relay performance is assessed on a periodic basis any material changes in relay behaviour can be identified, even if only a few relays are modelled. Where protection relays are not modelled, significant changes in busbar short-circuit current magnitudes may also be used as a proxy or indicator that protection performance may be compromised. This may prompt a protection coordination study for that relay at or near that busbar.

Standard industry terms are used in this paper where practical, but where non-standard or ambiguous terms are used supporting definitions are provided for the context of this body of work.

## 2 Simulation and network configuration

In designing a tool for analysing protection coordination, the process by which the protection is studied is critical. In running the simulation, a stepped-event process will yield much greater accuracy than simply applying a fault and noting relay pickup times. A stepped-event process is where a fault is simulated, and then re-simulated again after each circuit breaker opens. The simulation thus steps through the sequence of events from fault initiation to fault isolation or until no more relays are primed to trip. This approach ensures that the simulated protection relay performance takes account of the redistribution of fault current after each breaker operation.

This approach does increase the time to study a given fault as there will be approximately as many fault simulations as circuit breaker operations. This increase in simulation time may not be noticeable when studying a single fault, but where thousands of faults are studied, the impact can become significant.

### 2.1 Fault types and locations

In studying a given grid, the most common types of fault should be studied. This requirement may vary between grids, but any automated protection coordination tool should consider the common fault types including:

- single-phase to ground faults with zero and non-zero resistance,
- line-to-line faults with zero and non-zero resistance,
- double line to ground faults with zero and non-zero resistance,
- three-phase faults.

In studying each circuit, multiple fault locations may be considered. These may include close-in faults, remote-end fault, multiple faults along each circuit or any of these with the remote-end circuit breaker open. In selecting fault locations, some knowledge of the expected reach of relays should be considered. For instance, if distance relays are typically configured with a zone 1 reach of 85%, it may be prudent to study faults at 80 and 90% along each line (or 75 and 95%) in order to verify that all such relays are configured in line with protection setting philosophy.

In developing a list of feeders to fault, it is important that tapped, multi-terminal, and multi-section lines are assessed consistently. To avoid superfluous simulations, the fault locations should be calculated with respect to the distance between each true remote-end busbar rather than examining each line segment individually. For example, for a line with two sections with different conductor types, it may be sufficient to study 5% along the overall distance between busbars, rather than 5% of the first section of circuit.

## 2.2 Network contingencies and generator dispatch

Grid assets require maintenance to ensure safe and reliable operation. Some maintenance requires the asset to be de-energised; this is usually taken as a scheduled outage. Assets may also be forced out of service due to component failure, failure of protection systems, or other operational reasons. At any one point in time, a grid may have many assets out of service for either reason.

While it is relatively trivial to manually study the impact of an individual outage on protection coordination, it is more challenging to assess multiple outages as the permutations can grow quickly. Outside of protection, this is a common issue for contingency analysis in planning studies; however, many grid operators use of online contingency analysis tools to identify risks to the system in the near-time outage planning and real-time environments. In comparison, protection systems are rarely if ever studied for the real-time or near real-time system.

The selection of suitable contingencies is an art in itself, but for the purpose of protection studies, certain contingencies may be selected. Critical contingencies for protection studies may differ from those used for planning studies and thus, it may not be appropriate to use the same contingencies in both types of studies.

Outages impact the short-circuit current magnitude and distribution for a given fault and also the apparent impedance seen by a relay at any given location in the grid. For the purpose of studying protection coordination, contingencies should be selected in order to identify credible scenarios which result in undesired protection behaviour, whatever that should be. By identifying these scenarios, the protection engineer may apply engineering judgement to either optimise the protection settings to mitigate the issue or accept the risk of undesired behaviour. In the case of the latter, it can be helpful to document the case to aid outage planning efforts and contingency analysis.

In studying protection performance during contingencies, it should be noted that the worst case may not be the outage of any one line or transformer at the substation in which the relay is located. For instance, if a large generator is connected to a bus by two or more parallel overhead lines, then removing the generator transformer from service would have a much greater impact on short-circuit current levels in the area than any one line outage.

In the case of  $N-1$  and  $N-2$  outages based on largest short-circuit current infeed, it is important to consider positive- and zero-sequence currents separately. The zero-sequence current is dependent both the generators which are online at the time of the short circuit and also the number and location of grounded transformer neutrals, zig-zag transformers, and other grounded devices. At a given busbar, the transformer or line providing the largest positive-sequence current may differ from the largest source of zero-sequence current. Thus, they may influence overall protection performance in different ways and may warrant separate consideration.

The special case of mutual coupling between adjacent overhead lines on double circuit towers or underground cables in shared ducting should be considered. When two or more circuits are in close proximity, such as overhead lines carried by a shared tower, mutual inductive coupling will exist between the circuits. This effect is most notable in the zero-sequence impedance. This zero-sequence impedance mutual coupling can change dramatically if one of the circuits is on outage (circuit breakers open) or outaged and grounded at both ends. This can have the effect of causing overcurrent and impedance relays to over-reach and potentially misoperate [2]. As such, outaging as well as grounding coupled circuits may be warranted as separate contingencies when studying protection coordination.

The case of a circuit breaker failing to open may occur, in which case backup protection is expected to operate to isolate the fault. While comparatively rare, such events do occur.

There follows a non-exhaustive list of contingencies that may be considered for protection coordination studies:

- normal network case with all assets in service,
- $N-1$  of the largest local (same station) positive or zero-sequence short-circuit current infeed,

- $N-1$  of the largest regional positive or zero-sequence short-circuit current infeed,
- $N-1$  outage and grounding of one or more circuits on a multi-circuit line,
- $N-1$  of all local circuits in turn,
- $N-2$  the two largest short-circuit current infeeds,
- $N-2$  for dependent assets such as lines on shared circuit towers,
- sectionalising of busbar,
- inhibited breaker/circuit breaker fail.

A related consideration to selecting contingencies is the process of selecting suitable generator dispatches as these will directly determine the short-circuit current magnitude and distribution in a network. The short-circuit current contribution varies between different energy sources. Typical synchronous generators provide four to seven per unit positive- and negative-sequence short-circuit current on a per unit base of the generators rated current, whereas inverter-interfaced devices only supply positive- sequence current in the range of one to two per unit on a per unit base of the pre-fault current [3]. Note the difference in per unit base between the cases and the fact that inverters are not usually designed to provide negative-sequence current, although new Grid Code changes such as those in Germany are making negative-sequence current a requirement. Furthermore, inverter-interfaced energy devices tend to be situated far away from the main load centres and thus, where a conventional synchronous generator is taken offline the short-circuit level of the grid can be significantly affected.

In studying protection performance, the regional generation fleet should be considered based on credible operating scenarios. Example of some scenarios which may be considered include:

- typical peak synchronous generation case,
- emergency peak synchronous generation case (where lower merit order generators are operating),
- typical minimum synchronous generation case,
- 50% of variable generation operating case,
- 100% of variable generation operating case.

The above are examples only and may be more or less suitable depending on the grid in question. Future network conditions and engineering judgement may result in much fewer or different dispatches being considered to those above.

## 2.3 Protection performance assessment

In studying protection relay performance, a distinction is made between primary protection systems and backup protection systems. For the purpose of this analysis, a high-level definition of primary protection for lines and transformers is considered to be those devices that result in the minimum number of circuit breakers operating to isolate a fault on the protected asset. Thus, for an overhead line, the primary protection are the relays which trip the circuit breakers at each end of the line, while backup protection are the relays on adjacent lines and transformers. Thus, backup protection devices are all those protection devices not defined as primary protection.

While there are cases where these definitions may not be appropriate, they are intended to offer a generalised rule which enables a software tool to automatically distinguish between primary and backup protection.

In studying protection performance, each individual protection function may operate or fail to operate in its own unique way. For the purpose of assessing and summarising the performance of large numbers of protection devices, two performance assessment levels are proposed, namely (i) coordination performance and (ii) functional element performance. Coordination performance is proposed to provide a high-level indicator of how a particular relay performed in coordination with other relays for a given fault. This indicator is independent of relay type or tripping element. There follows an example list of protection coordination performance indicators. These are not proposed as a definitive set of indicators

or terms as these may vary depending on grid protection philosophy and the common protection failure types:

- instantaneous over-reach,
- slow tripping of primary protection for near-end fault,
- slow tripping of primary protection for remote-end fault,
- misoperation of backup protection relay,
- miscoordination of primary and backup protection relay,
- correct operation.

In the list above, instantaneous over-reach is considered to be any backup protection relay which trips with little or no delay after fault occurrence (e.g. within 20–80 ms). Slow tripping for near-end fault is considered to be where a primary protection relay trips with excessive delay for close faults on its protected asset, where close may be, for instance, between 50 and 85% along an overhead line. Similarly, slow tripping for remote-end fault is considered to be where a relay trips with excessive delay for faults near the remote-end busbar, for instance, on the last 15–50% of an overhead line. In each case, the tool should enable the user to configure the definition of each performance metric based on acceptable trip time delay or definition of near-end or remote-end faults.

Misoperation of a backup protection relay is where a backup protection relay trips after some time delay, but faster than the primary protection. This may occur due to slow primary protection or excessively fast backup protection.

Primary and backup protection are typically time-graded to ensure that they act in a coordinated manner; a miscoordination of primary and backup protection indicates that a backup protection relay has picked up and is primed to trip within a set time margin of the primary protection. Unlike a misoperation where the backup protection trips faster than primary protection, a miscoordination is where backup protection has not tripped, but there was insufficient time margin between primary and backup protection.

Finally, a correct operation is where either primary protection responded promptly to isolate a fault or in the case of circuit breaker failure where backup protection acts to isolate a fault.

In addition to the higher level performance indicators, more detailed indicators may be provided by protection functional element performance. These are concerned with indicating how individual elements performed within a relay and may be specific to a technology or algorithm. In order to evaluate relay performance against these indicators, bespoke fault simulations may be required with or without relay elements blocked from operating. This level of detail is typically only assessed during settings design and may not be necessary for wide-area coordination studies, but an automated tool may present the option to perform such detailed studies if a high-level protection issues (misoperations, miscoordination) is identified.

An example list of protection functional element performance indicators could include:

- fault current below instantaneous overcurrent pickup level for near-end fault,
- fault outside zone 1 of primary impedance relay for near-end fault,
- insufficient polarisation voltage or current for directional determination of primary protection.

### 3 Storing and visualising results

Automating the assessment of protection performance can yield significant time-savings in comparison to manual process. Automated analysis can, however, generate large quantities of data. Thus, in addition to automating the protection coordination studies, it is important to also consider automation and visualisation of the results. Otherwise, the time-savings in automating the analysis could easily be outweighed by the extra time required to analyse the results.

The protection engineer may have many use-cases for the output data from a wide-area coordination study, both in terms of post-processing, filtering, and visualisation. To that end, a suitable storage mechanism should be selected both for producing the

results of an individual study and also for storing sets of results over time. Options include CSV file, XML, local database (Access), centralised database (SQL, Oracle) among others. Each presents their own strengths and weakness for a given application.

CSV files are well understood and easy to create, but need external tools to analyse and visualise the data. XML enable defined data structures and can incorporate definitions for how the data should be displayed depending on where it is opened such as in a spreadsheet, database, or a web browser. Both options may be used in a standalone manner and can be shared easily between engineers. Centralised databases present challenges in their initial setup in terms of creating and maintaining the database and configuring an interface to it from the short-circuit tool, but may align better with corporate requirements for data storage, access, and backup.

#### 3.1 Visualisation of results

Studying protection performance for even small grid areas can generate significant quantity of data for an individual engineer to analyse. Some examples of reports that a protection engineer could require include:

- protection coordination at or near a particular station, line, transformer, or generator,
- a list of fault locations which give rise to particular protection issues (instantaneous over-reaches etc.),
- a list of relays whose performance has materially changed over some interval of time or with respect to some base or reference case,
- a list of busbars whose short-circuit current levels have changed by more than a certain magnitude or percentage value over some interval of time or with respect to some base or reference case.

The reporting infrastructure should ideally permit the development of both standardised and dynamic reporting to enable the user to quickly focus in on results of interest.

#### 3.2 Tracking changes in performance

The short-circuit tools used to simulate and test coordination of protection relays may not have every relay modelled and the relays that are modelled may have errors in the settings or not reflect the latest settings on the relays on site. Thus, if the coordination of all relays in a grid are studied, a large number of issues may be identified. It may take some time to review all of these issues and such work may form the basis for a longer-term project. Instead, it may be more practical for the protection engineer to be made aware of any changes in protection performance or short-circuit level over an interval of time.

Changes in protection performance may be detected directly by running short-circuit simulations and monitoring the response of modelled protection relays or indirectly by monitoring the busbar short-circuit current magnitude and flagging those where it changes by some magnitude or percentage. The latter is more crude as short-circuit current changes do not definitively indicate that protection performance has changed, but it is a useful indicator that further analysis may be warranted at locations where relays are not modelled.

### 4 Implementation using Aspen OneLiner and Electrocon CAPE

Having compiled these requirements, tools were developed for two popular short-circuit analysis tools – Aspen OneLiner [4] and Electrocon CAPE [5]. The tools are named the EPRI protection settings evaluation tool (PSET) [6, 7]. Both tools required a modest quantity of coding – ~5000 lines of code each – and extensive testing and validation using small test cases and large grids models shared by collaborating transmission and distribution grid companies. The tools are aimed at being production grade and for use by the wider transmission and distribution grid industry (Fig. 1).

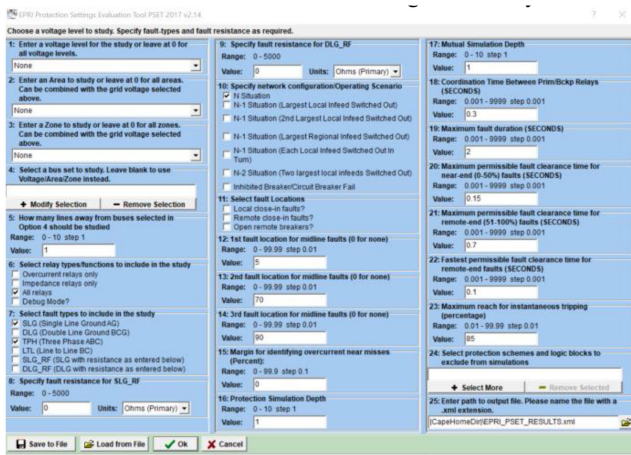


Fig. 1 Dialogue box of PSET for CAPE

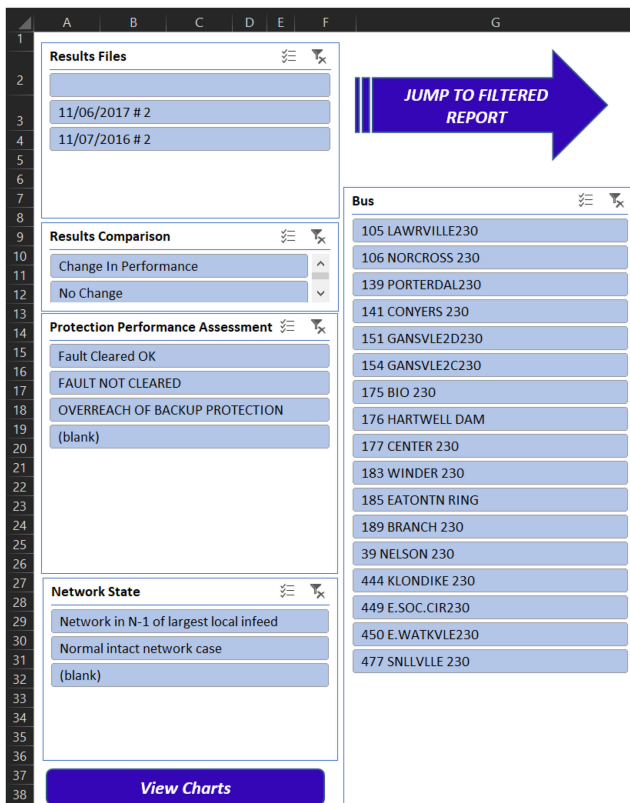


Fig. 2 Dynamic filters for PSET excel analysis worksheet

Both tools offer the user the option of selecting multiple fault types with and without fault resistance, multiple fault locations along each line, multiple grid scenarios including intact network, various  $N-1$  and  $N-2$  cases and circuit breaker fail. The region of a grid to study can be selected based on area, zone, voltage level, or lines within a certain proximity of selected busbars. In addition to performing the selected fault studies, the tools also record busbar short-circuit levels for all busbars within the studied area. This enables the tracking of fault levels over time and the automated identification of protection relays which are not modelled, but whose performance may have been impacted by the change in fault level.

An XML file format was selected for storing the output data. When the tools run, they create an XML file which holds the simulation options selected by the user for the study including study area, zone, voltage level, fault types and location, protection performance metrics, and detailed protection relay performance for each fault. By storing the configuration options used for the study

in the XML file, it is trivial to replicate the study in future or re-run the same analysis on a later version of the grid model. An XSD file is created which defines how the XML is structured – this enables the results data to be imported into databases. Finally, an XSL file is created which defines how the data should be displayed if the XML is loaded in a web browser or a spreadsheet. With this approach, the output can be directly viewed or imported into the tool of the user's choosing

While the XML file can be opened as a formatted spreadsheet directly, a custom spreadsheet was developed in Microsoft Excel to enable one or more results files to be loaded, analysed, and compared. With a combination of VBA code and Excel slicers, the user can dynamically report on protection performance and filter based on a number of different metrics, thus significantly speeding up engineer analysis of the results. Two or more sets of results may be compared in order to identify changes in protection performance over time or to assess high-level trends in performance such as increasing or decreasing fault clearance time, number of protection issues identified etc. (Fig. 2).

The tools have been tested to operate on grid sizes in excess of 5000 buses. The version of the tool for OneLiner has a speed of ~3 studies/s, while the version for CAPE has a speed of approximately one fault study every 2–3 s. The speed is dependent on the depth around the fault location in which relays are modelled and the complexity of the network.

Studies of a typical grid area can take a number of hours to complete, but given that no user interaction is required, once the analysis has begun, it is recommended that the tool is run overnight or over a weekend.

Owing to the duration of a typical study, the tool has been designed in an attempt to be as fault tolerant as practical and thus to avoid interruptions or crashes. The tool also creates its own detailed log file during execution to support diagnosis of any modelling issues encountered during the simulation such as invalid relay settings, incomplete relay models, missing current or voltage transformers etc.

## 5 Conclusions

This paper presented a selection of requirements for the development of an automated wide-area protection coordination assessment tool. These requirements were used to develop tools for performing such analysis using CAPE and OneLiner, two popular short-circuit analysis tools.

Both tools were coded by EPRI in collaboration with transmission utilities in the USA. The tools are in active use by EPRI member utilities and continue to be developed based on user feedback and industry needs.

## 6 Acknowledgments

EPRI would like to acknowledge the collaboration and support from all members of the Transmission Protection Research who aided in the production of the work discussed in this project.

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