CIGRE-449

2021 CIGRE Canada Conference & Expo
Toronto, Ontario, October 25-28, 2021

Methodologies and Tools for Full-Cycle Automation of Transmission Line Protection Settings Evaluation

Daniyal Qureshi[1], Hadi Khani[1],
James Kelly[2], Muna Anazodo[2], Pankaj Sharma[2] & Ryan Parappilly[2]
[1]Quanta Technology, Canada
[2]Hydro One Networks Inc., Canada

SUMMARY

As the quality of software models of real-world power systems increases, so does the quality of models of protection systems. To maximize the utility of these advanced protection models, there need to be tools and associated processes for evaluating the protection reliability that take full advantage of the software capabilities. One challenge in specifying an approach for evaluating protection systems for reliability performance is the determination and simulation of a multitude of operating conditions and scenarios that must be considered to accurately assess protection settings. Simultaneously, the approach must allow protection engineers to identify reliability issues in a manner that is quick and efficient.

This paper presents new methods and develops new tools for full-cycle automated implementation of the utility transmission line protection philosophy in a software application. Such approaches are then utilized on a protection model to allow engineers to evaluate the reliability of their protective devices both accurately and quickly. The proposed methods enable the evaluation of hundreds of simulation scenarios and contingencies for a very thorough relay setting evaluation, thereby capturing hidden setting issues that would have gone undetected otherwise. The paper outlines the primary system and protection modelling requirements that must be in place to analyze reliability performance in a software application.

In addition to automating the repetitive processes, this paper presents innovative methods to automate complex simulation cases that protection engineers typically perform. The paper describes various tests for diverse protection functions, such as distance, differential, and overcurrent, ranging from simulating faults and checking relay operation to comparing pickup values to user-specified ratios. The methodology of reporting the results in a concise format and indicating reliability issues to the engineer is presented and discussed.

The presented tools and approaches are applied on an actual large-scale system with more than 600 transmission lines and 500 transformers, where their feasibility and effectiveness are practically evaluated. It is shown that the developed tools significantly increase the efficiency in engineering review and successfully identify reliability issues that may manifest themselves in the real-world system.

KEYWORDS

Full-cycle automation, protection settings, evaluation, transmission systems, simulations, modelling.

DQureshi@Quanta-Technology.com

1 INTRODUCTION

It was the finding of the NERC Protection System Misoperations Task Force (PSMTF) in their 2013 *Misoperations Report* that the prevailing source of NERC-wide protection misoperations between January 1, 2011, and April 1, 2012, was incorrect settings – being the cause of 28% of recorded cases [1]. The second and third most likely causes were relay malfunctions and communication failures, leading to 20% and 17% of all cases, respectively, as shown in Figure 1.

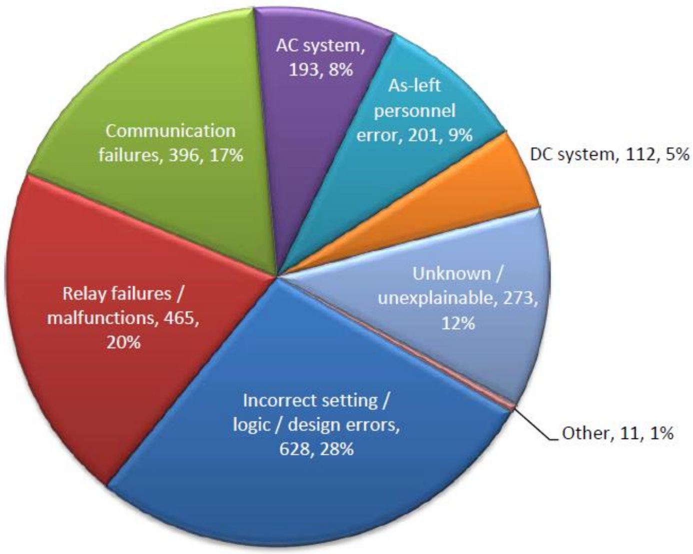


Figure 1. Identified causes behind misoperations across NERC area from January 1, 2011, to April 1, 2012, from NERC PSMTF's 2013 *Misoperations Report* [1].

As part of the suggestions to reduce settings errors proposed by the report, it was recommended that there be an increased peer review of new settings and periodic review of existing settings, evaluating whether the settings meet the requirements of the control application [1].

Thus, settings evaluation is an integral part of the settings design process for reliability performance. The increasing complexity of transmission system protection and the multitude of potential system contingencies under which protection must continue to operate as expected add difficulty to the challenge of specifying an extensive evaluation approach.

2 PROBLEM STATEMENT

To improve quality assurance/quality control, relay performance, and the accuracy of protection settings, tools and processes are required, allowing for a thorough evaluation of complex protection settings by a protection engineer before issuing the settings to the field. The ideal platform for this evaluation is in a software environment where the power system has been modelled, and fault scenarios can be effectively simulated. This is the most readily available and cost-efficient approach.

In the software environment, one challenge facing protection engineers in settings evaluation involves attempting to determine and simulate the large number of system operating conditions that the protective relay may encounter in its service. This must be done under budgetary and time constraints, which may not facilitate a complete investigation being performed, allowing certain settings failures to pass undetected and initiate misoperations in the real-world system.

Existing utility processes tend towards a manual solution, where the protection engineer manually simulates these fault scenarios and inputs measurements into settings calculation spreadsheets for evaluation of the settings. However, this method introduces the inevitable risk of human error. Furthermore, it is realistic that only a limited number of scenarios can be simulated, given the time required to manually establish test scenarios accurately. Budgetary constraints must account for these and, due to the human nature of this approach, it is hampered by difficulties in standardization of the process across different engineering resources.

A solution capable of addressing this issue without the aforementioned challenges is found in developing an automated settings evaluation process, relying on tools leveraging the accuracy and detail of the software model. It should automatically determine and simulate faults necessary to detect potential misoperations within the software environment, detecting where a settings failure has occurred as per the utility protection philosophy. It must then organize the findings into reports that the protection engineer can easily interpret. Lastly, the process should be quick and integrate well into existing utility procedures.

3 PROPOSED SOLUTION

The proposed tool is a script in the software environment referred to in this paper as the *automated settings evaluator*. Figure 2 shows the interaction between the protection model in software, the engineer, and the automated settings evaluator.

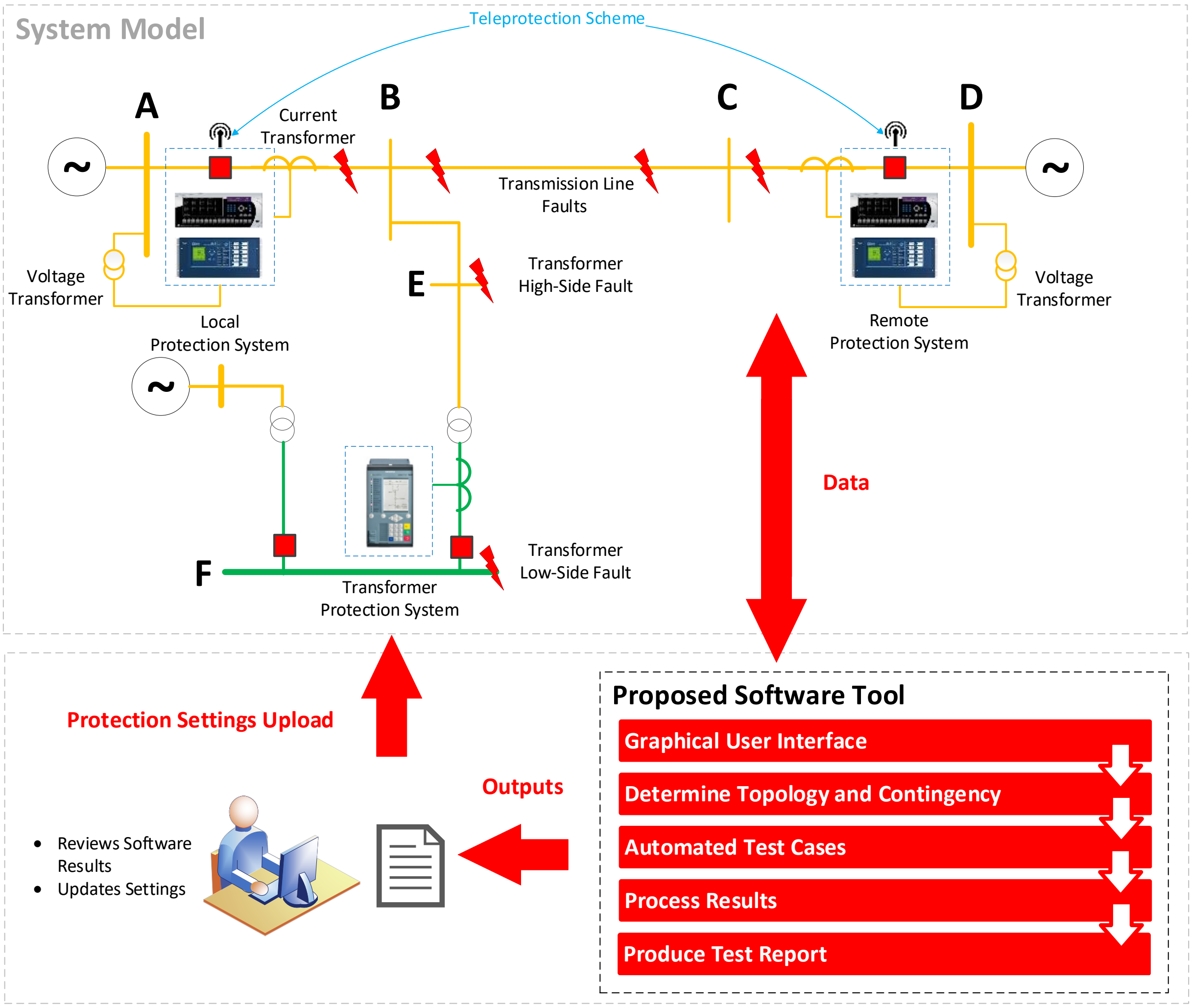


Figure 2. Integration of proposed software tool in settings design process.

After an engineer designs a setting file, they may upload the file directly into the software database and use the automated settings evaluator to perform a study on the line. They will then analyze the files generated by the tool, which present the information in a structured, easy-to-parse report. Figure 3 shows the process flow of the proposed automated settings evaluator in more detail.

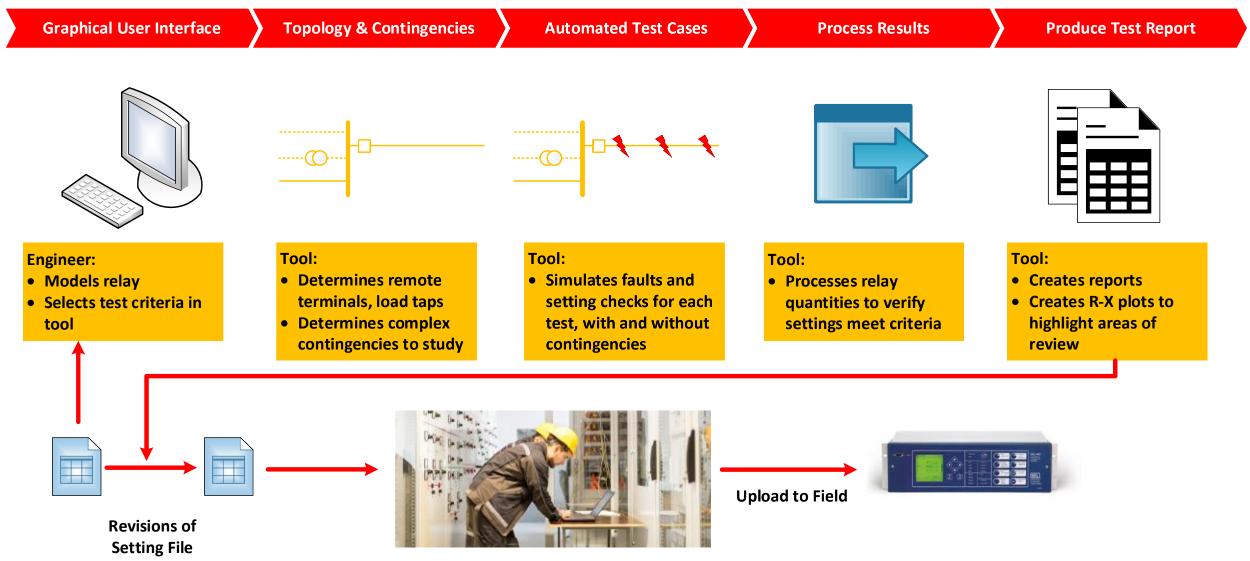


Figure 3. Process flow of automated settings evaluator.

Thousands of fault scenarios can be applied in the short-circuit software within minutes and summarized in organized text reports, allowing the engineer to rapidly assess the relay settings for a wide array of contingencies and conditions.

The automated settings evaluator tool evaluates the whole line based on the types of individual protective elements it locates at each terminal. These include modelled elements such as ground instantaneous overcurrent elements, phase/ground distance elements, and line differential elements. It reports the results in a readable output file per terminal with a judgement of Pass or Verify based on whether each element test meets the desired criteria or requires engineer verification. In addition, it produces files containing R-X plots of distance elements in the software environment. These reports are part of the utility relay commissioning process, and therefore the tool is an efficient way of automating documentation tasks which were previously manual.

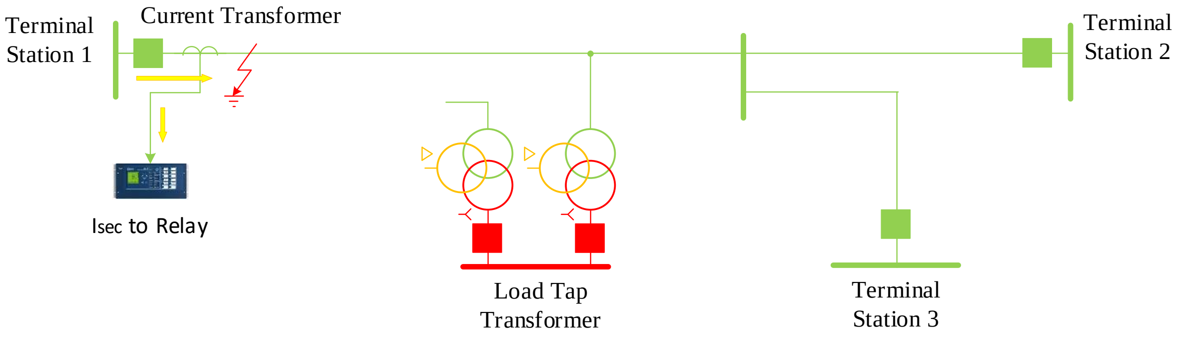
To successfully perform an automated settings evaluation study, an accurate system model is required, along with up-to-date protection information. The relay model should contain all protective functions to be evaluated and accurately simulate their curves/characteristics.

4 EVALUATION

The following sections summarize a selection of the comprehensive analyses performed by the automated settings evaluator to ensure that settings have been designed correctly.

Table 1. Different tests performed by the automated settings evaluator.

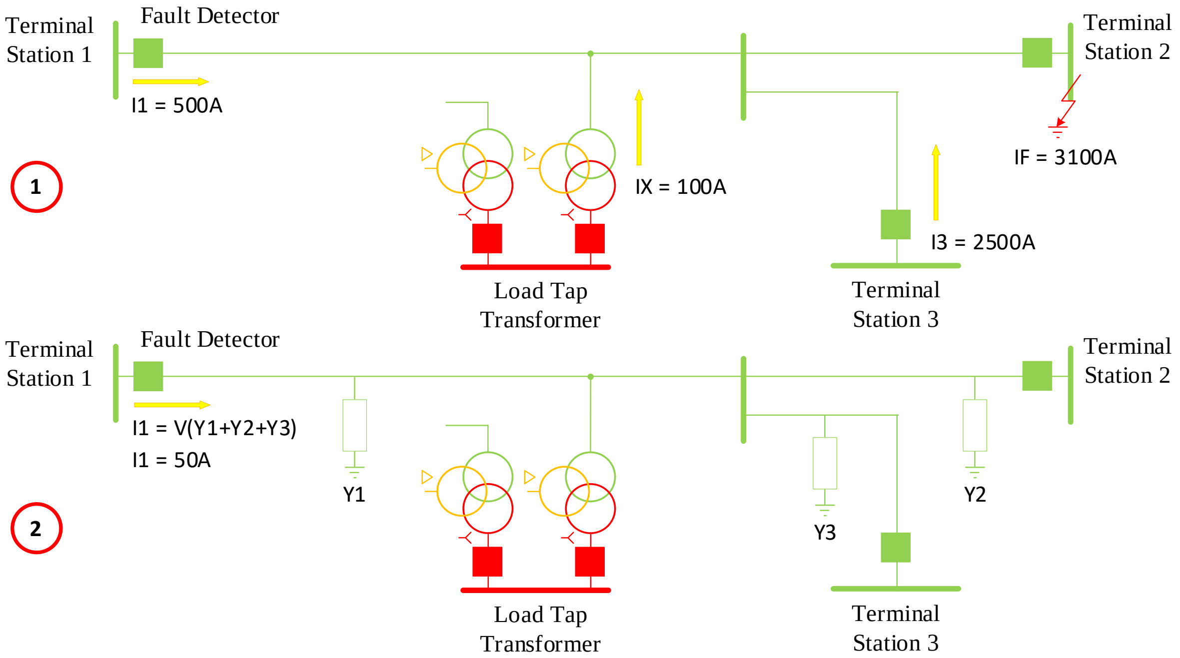
Function	**Evaluation**
Current Transformer	• Excessive fault current may severely damage relay equipment and render protection ineffectual. Ensures that the upper limit of secondary current fed into the relay from the **current** transformer (CT) remains below 100-A. • Tool applies close-in fault with the local bus at maximum continuous operating voltage and calculates secondary current.



Criteria: Isec < 100A

Figure 4. Close-in fault applied to calculate maximum secondary current of CT to relay.

Fault Detector	• Ensure fault detector is sensitive enough to detect line faults. • Tool simulates faults at the remote ends of the line and validates that the pickup setting is below 50% of the measured fault current. • Ensure fault detector prevents the distance elements from operating and tripping the circuit breaker during line energization. • Tool accumulates the total positive-sequence susceptance of the line and uses the local bus voltage to determine positive-sequence line charging current, validates that pickup is above 150% of this current value.



Criteria: (150% of 50A) < Ipk < (50% of 500A)

Figure 5. Example remote bus fault applied to calculate secondary current of CT to relay.

Distance Zones	• Under-reaching Zone 1 (typically set to a maximum of 80% of line impedance) is intended to trip instantaneously.

	• Over-reaching zone (typically set to a minimum of 120% of line impedance) is intended to trip after a fixed time delay, usually around 400-ms. • Tool finds the maximum point up until which the local zone will operate (accounting for factors such as mutual coupling) by simulating faults across the line according to a binary search algorithm.

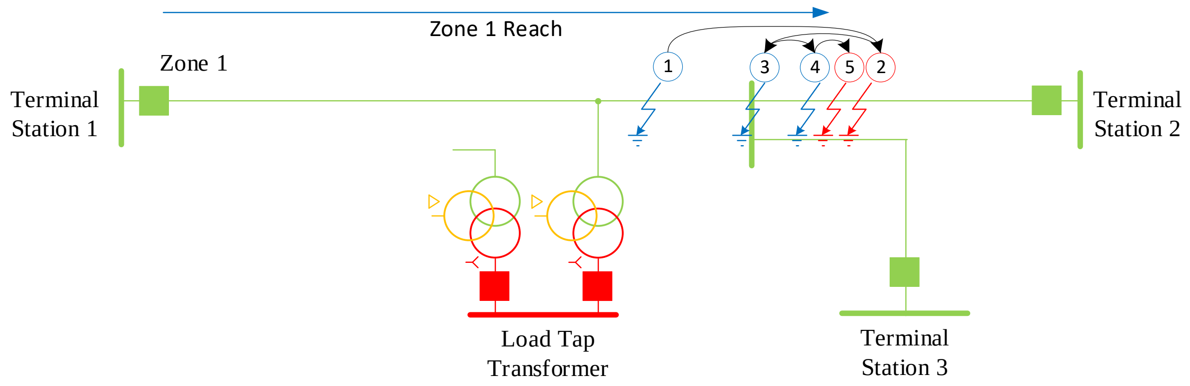


Figure 6. Binary search algorithm applied to determine actual reach of Zone 1.

Reverse Blocking Zone	• Directional comparison blocking (DCB) pilot scheme allows the local over-reaching zone to trip after a shortened delay if no blocking signal is received from the remote terminals during that period. • Ensure reach of the reverse zones covers a slightly greater impedance (safety margin of 10% of line impedance) on neighboring lines than the local over-reaching zone. • Tool uses a binary search algorithm to compare local and remote reverse zone reach and validates that safety margin is achieved.

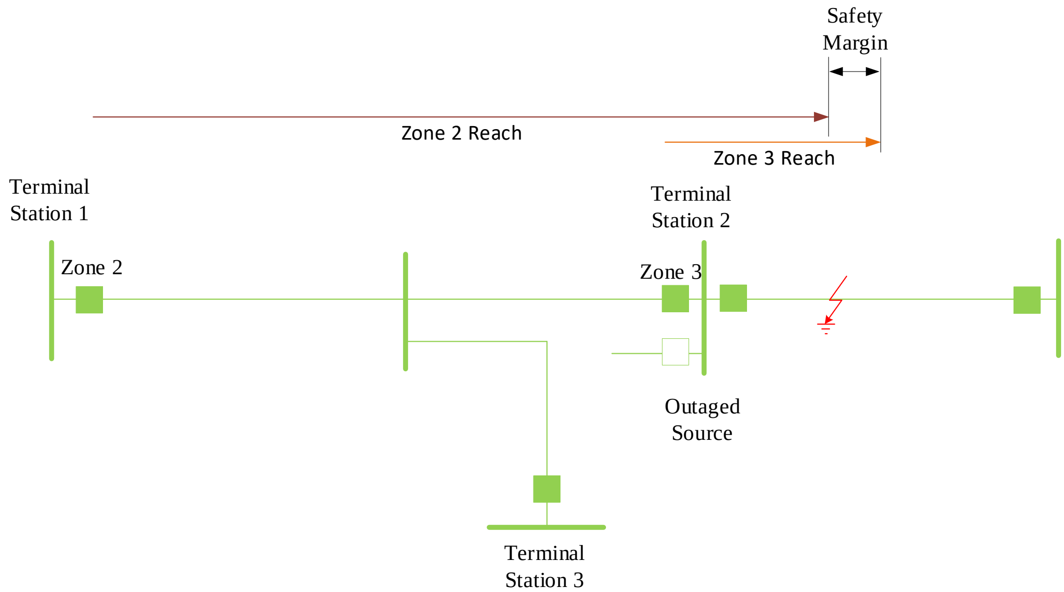


Figure 7. Evaluation of reverse-facing zone reach online with DCB scheme.

Source Impedance Ratio	• Usage of distance protection on lines with a source impedance ratio (SIR) > 4, considered to be short lines, may lead to misoperations. • Tool calculates and reports the SIR for lines with distance protection, as per the methodology specified in [2].

As well as repeating tests under N-1 system contingencies such as temporarily outaged remote terminals, load tap transformers, and mutually coupled lines, expert practices have involved evaluating over-reaching elements such as Zone 2 against a complex *half-source* contingency, wherein around half of the current sources at the local terminal are outaged. This represents a worst-case scenario for loss of fault current during which over-reaching elements should still meet their criteria for over-reach. The tool can recreate this contingency using a ranked infeed algorithm as detailed below:

- The tool identifies all local current sources and remote endpoints through a topology search at the beginning of the study.
- A fault is placed close-in at the remote terminal.
- Sources contributing fault current separated into their equipment categories (line, transformer, bus tie, and generator). Equipment drawing current away from the fault is ignored.
- Equipment is ranked from highest to the lowest magnitude of current infeed.
- Oddly ranked sources outaged (e.g. outage 1st, outage 3rd, outage 5th, etc.) in each category.

5 REPORTING PROCESS

After completing the above evaluations in the software environment, the tool produces outputs which assist the protection engineer in their review. Furthermore, it automates portions of the utility's required documentation tasks for relay commissioning, considerably reducing manual effort. This includes a list of tables for each test and R-X plots with the features shown in Figure 8.

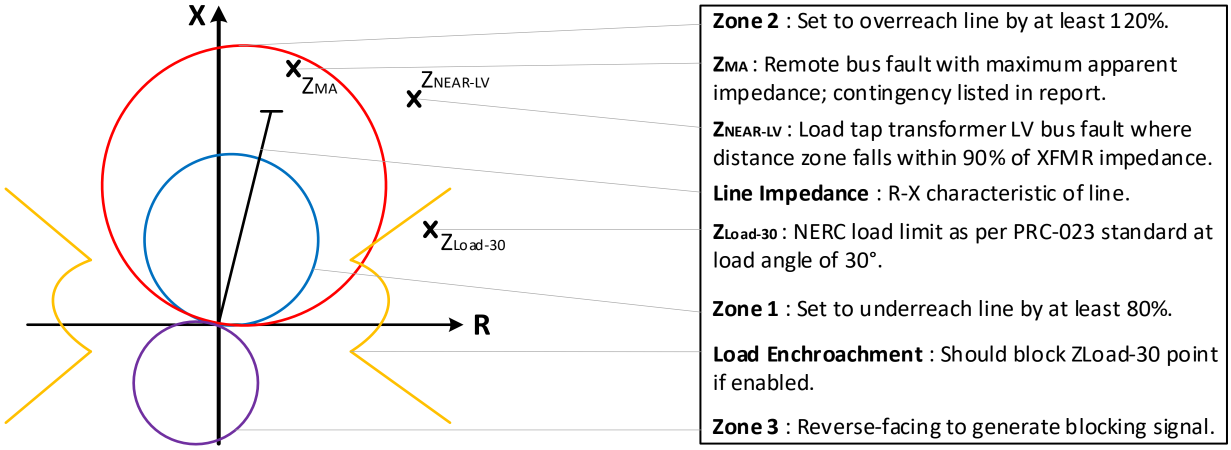


Figure 8. Output phase curve file exported by the automated settings evaluator.

6 RESULTS AND DISCUSSIONS

The tools and methodologies discussed in this paper have been applied to a real-world system containing over 600 transmission lines and 500 transformers to produce results. One example is described below.
On one line, a capacitor-coupled voltage transformer (CCVT) was connected as metering input to the local protection on a 500-kV line. The relay's sampling rate did not meet the Nyquist criterion to detect the high-frequency transients created by the CCVT in a fault event. Thus, the voltage waveform for an out of zone fault was distorted and impedance was undermeasured (seen in Figure 9).
The error in impedance measurement would not have cause misoperations for a longer line, but this line possessed a high SIR. The automated tool calculates the SIR for lines with distance protection and flags when the SIR > 4. It was found that the SIR for this line was flagged for review, which may have led to the prevention of the misoperation event.

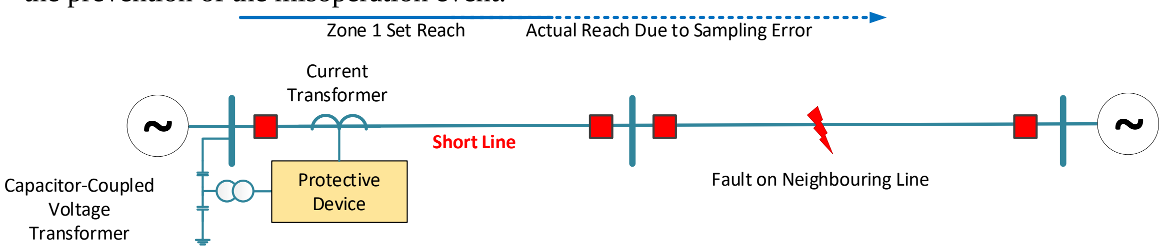
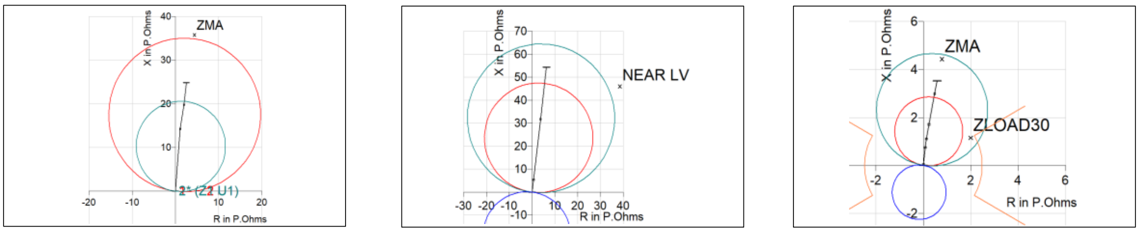


Figure 9. Zone 1 misoperation due to sampling rate inadequacy.

Figure 10 presents other cases of settings failures that can be caught by the tool.



1 **ZMA point falls outside of Zone 2 reach**

2 **Zone 2 reach nears LV bus of load tap XFMR**

3 **ZLoad30 point falls inside of Zone 2 reach**

Current transformer: LINE_CT_TO_CHARLIE "200_A"
The maximum secondary current for close-in faults should be below 100 A ...
For the CT tests, a local bus voltage of 1.00 p.u. was used.

No.	Fault	Outages Considered (Contingencies)	Fault Location	Meas. A,Prim	CT Ratio	Meas. A,Sec	Max A,Sec	Act. Ratio	PASS FAIL
1	SLG	None	Close-in at (####) ALPHA-CHARLIE	22088.3	200.0	110.44	100.00	1.10	FAIL
2	TPH	None	Close-in at (####) ALPHA-CHARLIE	25400.6	200.0	127.00	100.00	1.27	FAIL

4 **Current Transformer secondary current for remote faults > 100-A**

Alpha Substation 1000 DIST "21P1" (D60_v5.6x_5A); Contact Logic Code: 21P1_A
Testing zone 1 reach on path 100 ALPHA -150 JUNCTION - 1 to remote bus 300 CHARLIE (Alpha-Charlie)
The actual reach must be less than 80% (+/- 2.0 tolerance) (of the line impedance)

No.	Fault	Outages Considered (Contingencies)	Delay Sec.	Line Imp. Ohms	Line Angle Degrees	Set Reach Ohms	Set Reach %	Act. Reach %	Des. Reach %	PASS FAIL	Oper. Sec.	SIR
1	TPH	None	0.00	48.08	84.19	21.35	44.40	41.23	80.00	PASS	0.02	0.2943
2	TPH	Term. : 200 BRAVO	0.00	48.08	84.19	21.35	44.40	41.72	80.00	PASS	0.02	0.2793
3	TPH	Term. : 400 DELTA	0.00	48.08	84.19	21.35	44.40	43.18	80.00	PASS	0.02	4.7997

5 **Line Source Impedance Ratio > 4**

Testing pickup to be over 150% (+/- 2.0% tolerance) of line charging current...

Pickup A,Prim	Line Chg. A,Prim	Meas. Ratio	PASS FAIL
90.0	89.1	1.01	FAIL

6 **Distance Fault Detector pickup < 150% of line charging current**

Figure 10. Examples of settings failures that are caught by the tool.

7 CONCLUSION

In this paper, the authors identify the need to perform comprehensive protection settings evaluation in a software environment, given the increasing complexity of relay settings and the prevalence of settings errors as a cause of protection misoperation across the industry, as found by the NERC PSMTF 2013 *Misoperations Report*. For that purpose, automated tools and processes are specified, allowing for a thorough review of a diverse range of protective functions that are time and cost-efficient. Different tests required for each type of protective element are discussed. The automated settings evaluator can recreate N-1 system contingencies to test the protective elements, such as line and terminal outages, while simultaneously producing more complex contingencies, such as the half-source contingency, that would otherwise be determined by the protection engineer. The proposed tools and methodologies are applied to a real-world system. It is found that the tools are successfully able to detect potential sources of misoperations in the system. In an increasingly complex protection system, the automated settings evaluator offers a promising solution to improving reliability performance.

BIBLIOGRAPHY

[1] Misoperations Report. (NERC Protection System Misoperations Task Force. April 1, 2013).

[2] M.Thompson and A.Somani. "A Tutorial on Calculating Source Impedance Ratios for Determining Line Length" (68th Annual Conference for Protective Relay Engineers April 2015 pages 4-5)