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Robust Protection of Power Transmission Systems in Today's Restructured Environment

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SUMMARY

High penetration of distributed generation and more frequent changes in network topology are considered as new transmission system operation regimes which could introduce new challenges in maintaining security and dependability of the system protection. This study investigates the impacts of these new operation regimes on the dynamic behavior of the transmission system and protection coordination subsequently, and proposes effective setting coordination solution for maintaining the protection security and dependability. Advanced computation technique and machine learning algorithm are used to implement an intelligent adaptive protection scheme. It enables the distance relays in distinguishing between a possible protection coordination interference of multiple disturbances from real fault situations, which helps preventing potential mal-operations of the relays. The proposed method is implemented and tested on several IEEE test systems as well as Alberta real-sized transmission operator system. Our method is compared with the methods currently used in practice. Numerous simulations are conducted on the test system and results are discussed in detail.

KEYWORDS

Distributed generation, phasor measurement units, protection security and dependability, support vector machine algorithm, parallel computation technique

1. INTRODUCTION

The transmission system operation regimes are being changed today due to the change in operating practices aimed at accommodating renewable and distributed generation resources, as well as optimizing energy dispatch to minimize outages and operation cost. This may also result in more frequent changes in the network topology caused by multiple switching actions [1]-[2]. New challenges and risks are introduced in assuring the resilient operation of the power system upon experiencing these new regimes. Maintaining the transmission protection security and dependability under the mentioned operation circumstances is considered as one of the significant challenges that must be addressed when a resilient power system operation is a goal.

Multiple switching actions are mostly aimed towards reducing the system operational cost in real time [3]-[4] or implementing load shedding following a contingency [5]-[6]. They may also be associated with mitigation of cascade tripping, as well as equipment being taken out of service due to maintenance purposes. As a result, setting coordination of the distance relays may be affected due to the change of the network short circuit values for an evolving topology. Under such operating regimes, the network may not be well protected against probable and unpredictable disturbances under the new topology leading to an increase in the risk of resilient operation being diminished. In today's practice, there is no tool that will help review the adequacy of the protection coordination of the distance relays to perform studies on the impact of topology change due to corrective actions. Hence an assessment whether a change in the relay settings is needed to maintain the security and dependability of the power system protection at such times is typically not performed. Since the critical challenge is to perform the setting coordination check of distance relays on a real-sized system timely, this significantly time consuming task should be automated. Identifying the relays whose settings get affected following a network topology change could be considered as an initial step in conducting automated settings coordination check.

Moreover, as DG penetration grows in the power system, the dynamic behavior of the system gets affected, which extends protection concerns to the transmission level in addition to distribution [7]-[8]. According to the IEEE and other interconnection standards, it is mandatory to have control and protection measures on DG interconnections to minimize the duration and probability of an inadvertent island occurrence. Several anti-islanding protection schemes are proposed and implemented based on the necessity to operate instantaneously and detach the DG from the grid under an unintended islanding case. The basic idea is sensing the voltage and frequency deviations and checking them against the threshold values to come up with the control action. These sensitive protection measures could affect the DG output unnecessarily under certain circumstances and aggravate the power system dynamic behavior during or after disturbances. Under-voltage sensitivity is an important indicator of such conditions. The voltage sag caused by severe disturbances such as 3-phase faults at the transmission side could propagate to the distribution level and interfere with DG operating under voltage protection measures and lead to unintended DG tripping. This might not raise any significant issue if the existing DG in the system is of a small scale and the system is well-designed for handling that. However, in case of high penetration of DG in the distribution network, the large scale tripping of the DG units puts an extra power flow burden on the system that is already under stress from previous disturbance. As a result, protection coordination of distance relays' backup protective zones on transmission side might get affected and the situation might be recognized as an actual fault by the distance relays mistakenly leading to their mal-operation. The mal-operation of distance relays under such stressed condition could aggravate the situation to the point that the whole or a great portion of the transmission system would collapse subsequently, which is called a cascade event. Although the impacts of unintended DG tripping on transmission protection coordination has been brought up in the literature [7]-[8], no proven protection coordination scheme has been specifically proposed against undesirable tripping of distance relays under such circumstances.

The focus of this research is to propose novel protection schemes as supplement to the current distance protection mechanism to remove or mitigate the risks that may deteriorate robust protection operation. An automated approach to examine the adequacy of the network relay settings for an evolving network topology and identify the consequent vulnerable relays at selected locations in the transmission system has been proposed and implemented. This accomplishment was the outcome of a three-year-long multi-million-dollar project entitled "Robust Adaptive Network Topology Control (RATC)" granted by ARPA/E [9]. Parallel computation technique has been innovatively used in the proposed algorithm to increase the calculation speed. The module's performance has been tested and verified on the Alberta transmission operator system as a real-sized system by comparing the results with the commercial package (CAPE) and proved to be significantly faster. The new concept of "Distance of Impact (DoI)" has been introduced following numerous simulations on the test case which identifies how far, in terms of the electrical distance, from the location of the switching action, one could expect the distance relays to get affected. It is shown that a huge amount of computation burden is saved by employing this measure and performing the calculations only for the necessary parts of the network rather than the whole network. The proposed module could be used in practice to assess multiple switching impacts on the network relay settings and identify vulnerable relay settings for taking a proper action. It provides the network operator with an extra decision making tool to deal with the impact of switching actions on the protection security and dependability.

Being able to identify the affected relays to a network topology change in the system, an intelligent protection scheme based on support vector machine (SVM) learning technique is presented to prevent distance relay mal-operation following unintended bulk DG tripping and maintain the power system resiliency. Proper wide-area (WA) measurements obtained from phasor measurement units (PMUs) are used to improve the proposed scheme's accuracy. The SVM based algorithm is trained such that it detects any distance settings coordination violation caused by the DG tripping events and avoids any consequent mal-operation of the relay. It acts as the supervisory control of the conventional trip signal resulting from the distance mho elements' pickup and blocks any follow on distance relay mal-operation. Unlike the conventional blocking schemes, the proposed method is able to not only block the relay operation due to DG tripping interference, but also unblock it if necessary, e.g. in case of detecting an actual fault during the blocking period. The proposed scheme is easily and quickly trainable for various possible scenarios of power system operation in practice and gives significant selectivity of relay operation. It could be considered as another complementary application of machine learning technique along with previously proposed ones to obtain a comprehensive supervisory control protection scheme and improves the protection security and dependability.

2. PROPOSED SETTING ADEQUACY CHECK MODULE

The idea is to perform fast relays setting calculation for an evolving network topology and compare the new settings with the previous ones to assess the adequacy of the settings for the new topology. The module's general flowchart is illustrated at Fig. 1. The focus is to make the setting calculation process faster by investigating how to reduce the calculation burden and problem size.

2.1. PARALLEL COMPUTATION TECHNIQUE

Most of the algorithm's computation burden lies within creation of different fault type databases, three blocks highlighted in Fig. 1. Specifically, line-end fault database preparation is a very time consuming task. This is because the power system impedance matrix (Z_{bus}) is a big order sparse matrix for which operations such as inversion and multiplication performed in short circuit calculations require more computation efforts. Each of the fault databases contains the bus voltage and branch current values for the corresponding type of fault which are then used to calculate the associated apparent impedances. To improve the calculation speed, parallel computation could be performed on the database calculations. Figure 2 shows the general flowchart of implementing parallel computation for N tasks each of which might contain several sub-tasks. For the parallel computation to be implemented, the tasks should be independent from each other, i.e., there should be no flow of data required between the tasks for each of them to be completed. In that case, all the tasks could be submitted to a group of workers (computing nodes) called pool of workers. The access to input data is provided for all the workers so they can use the same input data.

Figure 3 shows a simple view of the required fault calculations in setting a distance relay. Now, as an example, let's discuss how the line-end fault database preparation could be parallelized. Equations (1) to (6) are conducted to obtain the voltages of all the buses for a line-end fault implemented on the *j* side of the line from bus *i* to bus *j* in which Nbu , Y_{ij} , Z^{col} , V_n^{pre} and V_n^{post} are number of buses in the system, the admittance of the line, updated column of Z_{bus}, pre-fault and post-fault voltages of bus *n* respectively.

$$U_{Nbu\times 1} = \begin{array}{c} \begin{array}{ccccc} & & i & & \end{array} \\ \begin{bmatrix} 0 & \cdots & -Y_{ij} & \cdots & 0 \end{bmatrix}^T \end{array} \qquad (1)$$

$$V_{Nbu\times 2} = \begin{array}{c} \begin{array}{cccccccccc} & & & i & j & & & & \end{array} \\ \begin{bmatrix} 0 & \cdots & 0 & 1 & 0 & \cdots & \cdots & \cdots & 0 \\ 0 & \cdots & \cdots & \cdots & 0 & 1 & 0 & \cdots & 0 \end{bmatrix}^T \end{array} \qquad (2)$$

$$\Delta = \begin{bmatrix} 0 & Y_{ij} \\ Y_{ij} & -(Y_{ij}+Y_{sh}) \end{bmatrix} \qquad (3)$$

$$\begin{aligned} W &= \left(I_{2\times 2} + \Delta \times V^T \times Z_{bus} \times V\right)^{-1} \times \Delta \\ X &= Z_{bus} \times V \times W \times V^T \times Z_{bus} \\ Z &= \left(Z_{bus} - X\right) \times U \end{aligned} \qquad (4)$$

$$Z^{col} = \frac{1}{Y_{ij} + Y_{sh} - U^T \times Z} \begin{bmatrix} Z \\ -1 \end{bmatrix}_{(Nbu+1)\times 1} \qquad (5)$$

$$V_n^{post} = V_n^{pre}\left(1 - \frac{Z_{n1}^{col}}{Z_{(Nbu+1)1}^{col}}\right) \quad n \in \{1, \ldots, Nbu\} \qquad (6)$$

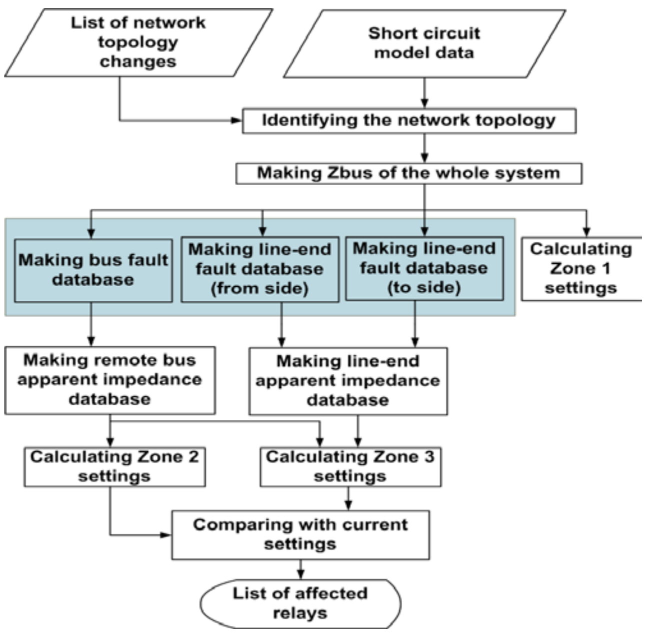

Figure 1. General flowchart of the relay setting calculation module

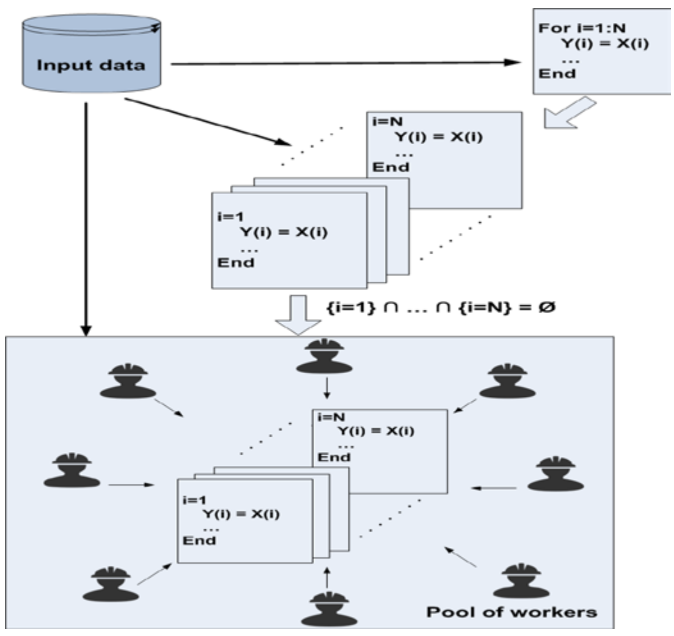

Figure 2. General implementation of parallel computation for N tasks

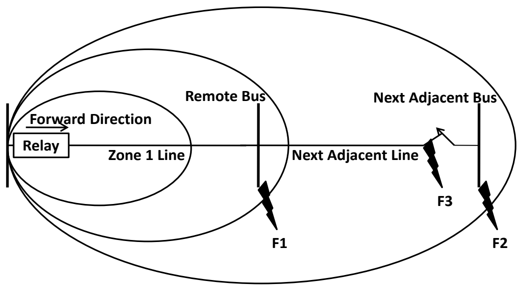

Figure 3. Fault types used for phase distance setting calculation: remote bus fault (F1), next adjacent bus fault (F2), and line-end fault (F3)

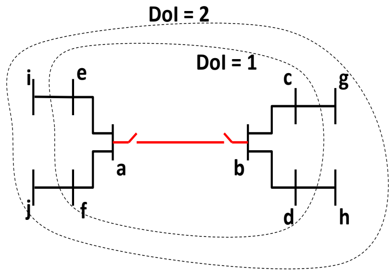

Figure 4. Illustrating the concept of DoI

The same applies for all the other branches of the system. As it could be understood from these equations, they could be conducted for branch *n* completely independent from those of branch *m*. For each implemented fault, the voltage of all the buses could be calculated and stored separately. This allows implementation of the parallel computation. The same process could be taken for the remote bus fault calculations, which could be performed much faster as no change to Z_{bus} is required to implement it. For a fault implemented on bus *n*, Z^{col} is simply the n^{th} column of Z_{bus} and there is no need to conduct (4)-(5). The network Z_{bus} is the only common data fed into the three blocks. Having the voltages at both ends of the branches corresponding to each fault case together with their impedances, the branches currents could be easily calculated.

2.2. DISTANCE OF IMPACT CONCEPT

For the algorithm to be practical for real-time applications in real-sized networks, the calculation burden and corresponding time should be reduced further. For this purpose, we have investigated the distance-of-impact (DoI) concept, which determines how far from a switching action we could expect the relay settings to be affected. This has been verified from conducting numerous simulations on the test systems as it would be discussed in the simulation results. In the case that the switching actions impact on the relay settings is limited to a certain electrical distance from the switching location, the calculations are then focused on the portion of the network within that distance. Figure 4 illustrates an example to clarify the DoI concept. For the switched transmission line a-b, the DoI of one includes the buses c to f with their corresponding branches and relays, and DoI of two includes those of the buses c to j.

3. PROPOSED SVM-BASED PROTECTION APPROACH

The candidate relays which are vulnerable to DG tripping events in a system are identified by the above mentioned module. In this part of the research, a SVM based protection scheme which enables those vulnerable distance relay to distinguish between a fault and a DG tripping scenario when interfering with the protection coordination of distance backup protective zones is proposed. The detection is based on the DG tripping impact on the system dynamic behavior. SVM is a relatively new and promising machine learning technique to be deployed as a pattern recognition and classification tool [10]. In this method, first, the input data is mapped into feature space which is a high-dimensional dot product space and then it is classified through a hyper-plane. The idea is to create p two-class rules which are separated by p decision functions. For example, the vectors of class k are separated from the other vectors by the k^{th} function $w_k^T \phi(x) + b$. However, all the decision functions are obtained by solving one problem as follows:

$$\min \ \frac{1}{2}\sum_{k=1}^{p} w_k^T w_k + C\sum_{i=1}^{l}\sum_{k\neq y_i} \xi_i^k w_{y_i}^T \phi(x_i)$$
$$+ b_{y_i} \geq w_k^T \phi(x_i) + b_m + 2 - \xi_i^k$$
$$s.t. \quad \xi_i^k \geq 0 \quad \text{for } i = 1,\dots,l \ \& \ k \in \{1,\dots,p\} \setminus y_i$$

And the decision function is:

$$\operatorname{argmax}_{k=1,\dots,p} \left(w_k^T \phi(x) + b_m \right)$$

In which *w*, *b*, ξ_i , *and C* are vector of weights, biased scalar, slack variable, and penalty factor respectively. More details regarding the mathematical background for SVM algorithm are brought in [10].

As shown in Fig. 5, two multiclass SVMs are deployed, one is trained based on local data only (SVM-1) and

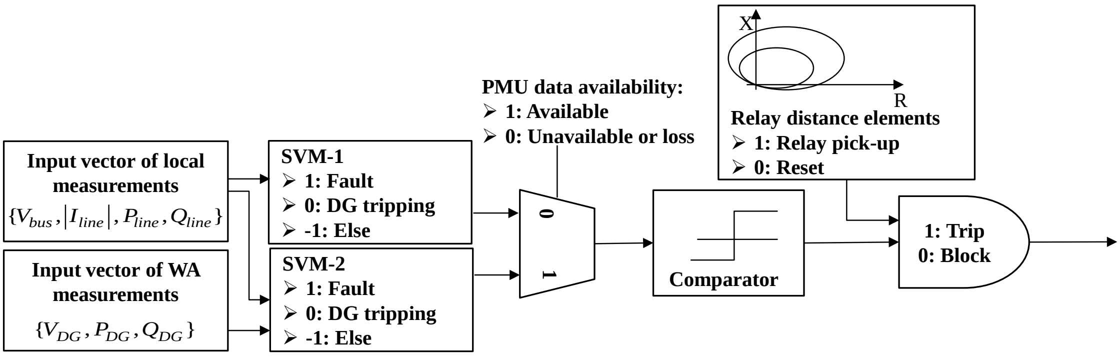

Figure 5. Block diagram of the proposed scheme

the other one is provided with WA data as well (SVM-2). Based on whether the PMU data is being received at the relay location or not, the method could switch between the employed SVMs outputs through the multiplexer shown in Fig. 5. This is for maintaining the scheme's robustness under probable PMU data unavailability or loss; however, the accuracy may decrease to some extent when using local data only as will be discussed in Section 4.2. SVM-1 and SVM-2 are trained to classify fault, DG tripping, and other cases as "1", "0", and "-1" respectively. The outputs of these SVMs are filtered by a comparator as class label -1 is not of interest. The logical AND of the backup protective zones pickup signal and the output of the comparator, as shown in Fig. 5, determines the trip/block signal value, i.e. 1 or 0.

A proper modelling of the DG units is important to get a fair observation of their impact on the dynamic behaviour of the network following a disturbance. In this study, the focus is on the converter based DGs (photovoltaic-PVs) modelled as current controlled sources [7] or active and reactive power sources [11] since the fast transients corresponding to electronic switches operation and control in these converters do not play a role for this study's purpose.

Local measurements and calculations at the relay point are the required elements of almost all the protection schemes. Features selected from the local measurements as inputs for both SVMs are: $V_{bus}, |I_{line}|, P_{line}$, and Q_{line} representing the bus voltage phasor, line current phasor magnitude, line active and reactive power flow respectively. Thanks to the PMU technology, WA measurements from various points of the system could be provided. When employing WA measurements technology, implementation cost must be considered for the method to be economically justifiable. In other words, the more PMUs are deployed; the significantly higher implementation cost would be experienced although a better system behavior observation may be obtained. It is assumed that phasor measurements from the PCC and target relay bus in regards to the reference bus are available. By the PCC, only the distribution to upstream connection bus is meant rather than all of the DG units' interconnections individually. Therefore, implementing the proposed method would be economically practical. Net active (P_{DG}) and reactive (Q_{DG}) power injections from the PCC into the transmission grid calculated from the PCC's PMU measurements are two good features to be utilized to improve the SVM-2 pattern recognition and classification accuracy. The other proper feature is the voltage phasor at the PCC on the grid side (V_{DG}). Deploying these measurements and calculations is specifically beneficial to improve the SVM's performance accuracy when classifying under more complicated scenarios such as detecting a second fault when the system is already under the stress of a post fault and subsequent DG tripping events. As it will be shown in the Section 4.2, the proposed scheme is able to detect such cases and unblock the trip signal so the protection security and dependability is well balanced.

In order to have realistic scenarios of the severe disturbance impact propagation from transmission to distribution level, the SVM training scenarios include different DG capacities at various instances following 3-phase faults at different points in the vicinity of the DG placement. Having prepared the training data set, the SVMs can go through the learning process and their performance is verified using the testing data set as discussed in the following Section.

4. SIMULATION RESULTS

As mentioned before, this study has two main parts: 1) proposing and implementing an automated fast distance setting calculation approach for identifying the vulnerable relays for an evolving network topology and 2) proposing a SVM-based protection scheme for identifying the relays vulnerable to unintended DG tripping cases in the system. The simulation results corresponding to each part will be discussed next.

Table I. N-2 Contingency cases affecting major relay settings

Rank	Lines (from-to)	No. of Affected Relays	DoI
1	89-91 & 579-585	29	5
2	420-865 & 666-1691	29	5
3	420-865 & 1318-1344	25	5
4	207-590 & 666-1200	23	3
5	208-581 & 242-253	23	4
6	35-331 & 167-737	22	5
7	297-483 & 669-677	22	5
8	35-331 & 666-1670	22	5
9	152-988 & 1431-1484	22	4
10	63-821 & 136-514	21	4

4.1. Identifying the vulnerable relays in the system

The proposed setting calculation module has been tested using various test systems and results have been verified by comparison with the commercial CAPE software, which was reported in a recent DOE study [9]. The results from the Alberta transmission operator system are provided below to stress the module's performance for real-sized system. The module has been coded in MATLAB and Java, and Texas A&M supercomputing facility has been deployed to conduct this part of the study [12]. A sensitivity analysis including 1000 random N-2 contingency cases from all over the network is conducted and critical cases have been identified, as shown in Table I. The top 10 N-2 contingency cases with major impact on the relay settings are shown in this table. A relay is considered affected if its zone 2 or 3 settings change beyond 5%. Figure 6 shows the role of parallelization in increasing the calculation speed. The first case of Table I is chosen to be run with the module when having access to different numbers of workers. As it could be seen from Fig. 6, the calculation time is significantly reduced as the number of available workers increases.

Having investigated all 1000 cases, it is concluded that the DoI never extends beyond 5 for this system. Table I shows the DoI for the top 10 N-2 contingency cases. Considering that, the required number of calculations to identify the affected relay settings following the network topology change reduces drastically as they should be performed for a limited part rather than the whole network. Figure 7 shows the computation time with and without implementing DoI for the 10 cases ranked in Table I; the parallel computation is still deployed for all the cases when having access to 30 processing nodes.

4.2. SVM-based Classification

Having implemented the above mentioned setting calculation and adequacy check module, the relays vulnerable to DG tripping could be identified. For this part of the study, New England 39 bus system is chosen to be run using PSS/E software for implementing real-time simulations and providing input data for SVMs training and testing. This system is chosen since the required dynamic data was available. As it could be seen from Fig. 8, it is assumed that DG is interconnected to the power system through PCC on bus 27. Top three relays vulnerable to the DG tripping scenarios assumed for this system are identified to be R_{25-26}, R_{29-26}, and R_{16-17}. They are determined according to the output of the setting calculation module that was run on this test system. Relay R_{25-26} is chosen as the most critical relay in this system to implement the proposed SVM-based

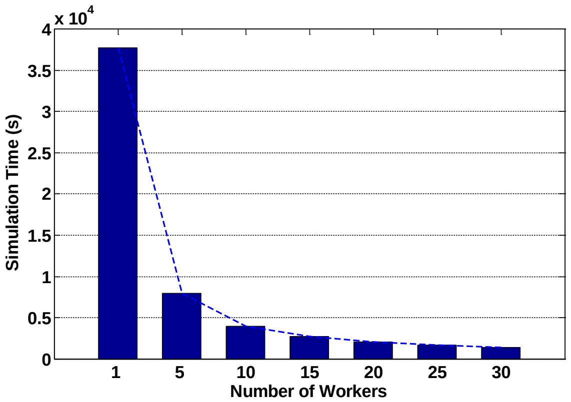

Figure 6. Simulation time for case ranked 1st in Table I

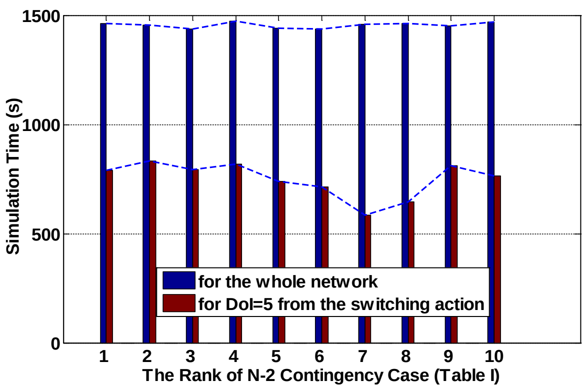

Figure 7. Simulation time comparison between with and without implementing DoI for 10 cases in Table I

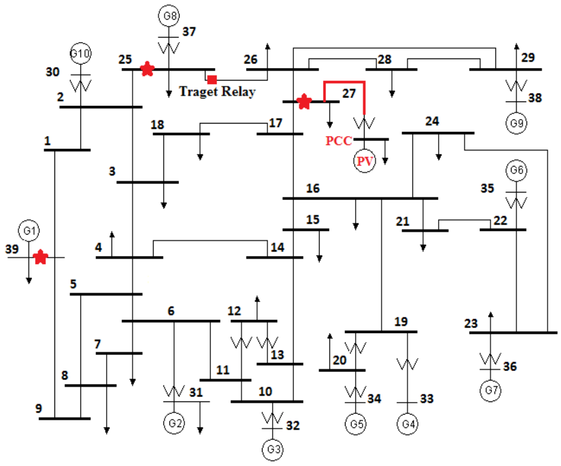

Figure 8. One-line diagram of New-England 39 bus system with DG penetration

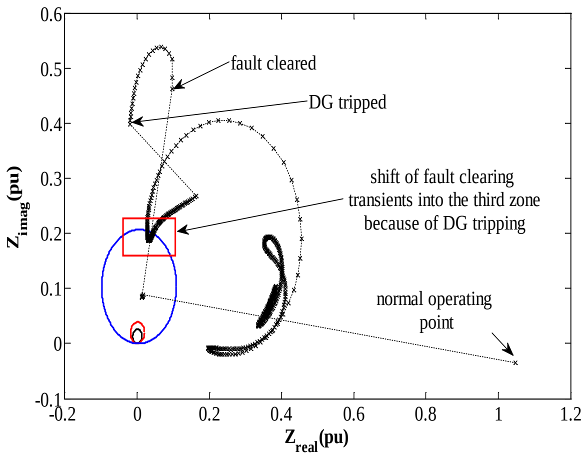

Figure 9. The apparent impedance trajectory for a DG tripping scenario following a short circuit in the system

scheme. Figure 9 shows the apparent impedance trajectory seen by the target relay ($R_{25\text{-}26}$) when a 3-phase fault happens in the middle of the line 26-29, which clears after 0.2 second by tripping the line 26-29 out, and then 0.27 second later 150 MW PV is tripped. As Fig. 9 shows, the DG tripping has caused the impedance trajectory after the fault clearing to be shifted into the third zone of the relay, which can initiate a false trip as a result. According to measurements from the simulation, the target relay sees the impedance trajectory in its third zone for about 60 cycles, which is critically close to issuing a trip signal. Obviously, based on the DG tripped capacity and the instant of DG tripping, the zone interference increases or decreases.

The SVM training data set consists of different cases (84 cases in total) including: 3 DG tripped capacities (100 MW, 250 MW, and 500 MW), faults at different distances in the vicinity of the DG placement, which also includes some points along the lines in the third zone of the target relay, and multiple DG tripping instants following the disturbance. According to the IEEE standard, the anti-islanding schemes should be able to trip DGs within 0.16 to 2 seconds depending on the level of voltage and frequency variations. The reporting rate of the PMUs is considered 60 phasors per second in a 60 Hz system according to the standard. Each instance of training includes 2 cycles of data. Considering all the simulated training cases, i.e. 84 cases of one-and-half seconds system operation time, the training set consists of 3780 instances. The same procedure is taken to create the testing data set. However, the conditions including DG tripped capacity, fault location and instant of DG tripping, are chosen intentionally to be different from the training set to assess the performance of the SVMs for unseen scenarios. In total, there are 1692 instances in the testing data set.

Table II shows the SVMs classification accuracy obtained in both cases of using local measurements only (SVM-1), and including WA measurements as well (SVM-2). As it could be seen, the classification accuracy has been increased to a very desirable level when employing WA measurements; however, an acceptable accuracy is still achieved while using local measurements only. Figure 10 compares the proposed method output, i.e. trip/block signal in Fig. 5, using SVM-1 and SVM-2 with the conventional relay pickup on a testing scenario. The testing scenario is that a 3-phase fault happens on x = 0.3 of the line 26-29 at t = 1s, and cleared at t = 1.2s by tripping this line out. As a consequence of miss-detection of PV interconnection relays on the distribution side, at t = 1.65s, 250 MW PV is tripped unintentionally. To further complicate the testing scenario and examine the method’s performance, a second fault is simulated on x = 0.4 of the line 26-28 at t = 2.5s when the system is already experiencing the stress caused by previous fault and subsequent DG tripping. As it may be seen from Fig. 10, following DG tripping, the distance element of the target relay backup zone (zone 3) has picked up from t = 1.8s to the end while the proposed method blocks the relay operation during DG tripping interference and unblocks it at t = 2.5s when the second fault happens. It is also seen that SVM-2 has classified the instances with a better accuracy compared to SVM-1 especially during the second fault detection.

Table II. SVMs specifications

SVM No.	SVM-1	SVM-2
Testing Accuracy (%)	93.8	97.6
Training Time (s)	39.67	8.76
Testing Time (s)	0.147	0.19

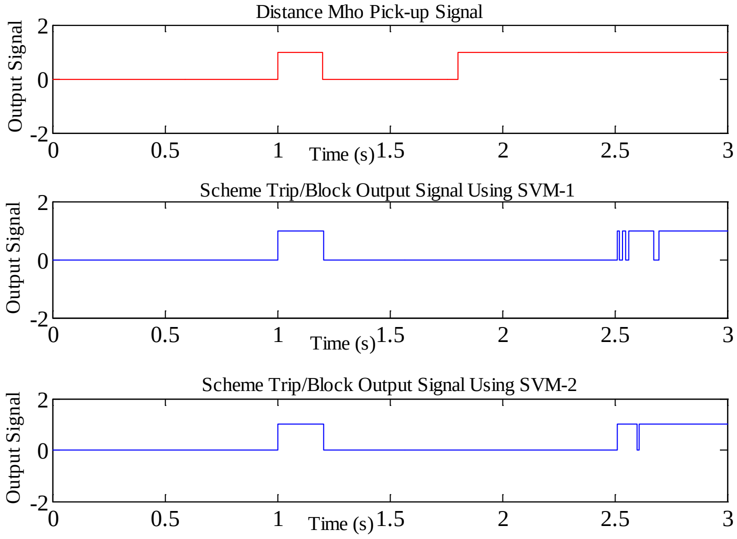

Figure 10. Comparison of the proposed method output with the conventional distance pickup

5. CONCLUSION

This study investigated the impacts of network topology changes and unintended DG tripping events on maintaining transmission network protection security and dependability that may be affected as a consequence of the new operation regimes in today's power system. A setting calculation and coordination check module using parallel computation technique was proposed and implemented on Alberta TOP system and it was shown that the computation speed has significantly improved. Numerous simulations were performed on the various test systems and the concept of DoI was introduced which effectively reduces the computation burden by limiting the calculations on the limited and required part of the network following a network topology change. For the distance relays vulnerable to DG tripping events in a system, a SVM-based protection scheme was proposed, which enables the relays to distinguish faults from DG tripping events. WA measurements were employed to increase the proposed method accuracy. The method was implemented and tested on New England 39 bus test system and it was shown that it effectively maintains the protection security and dependability following DG tripping cases.

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