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Reliable Implementation of Robust Adaptive Topology Control

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Abstract

The topology (transmission line) switching to achieve economic and reliability gains in the power grid has been proposed some time ago. This approach did not gain much attention until recently when large penetration of renewable generation created incentives to use transmission line switching to control sudden changes in power flows and mitigate contingencies caused by the generation variability. This paper explores implementation issues related to circuit breaker (CB) monitoring, relay setting coordination and detection of relay misoperations in the context of the topology switching sequence implementation. The paper covers risk-based assessment of CB status needed for determination of reliable switching sequences; it indicates how relay settings may be changed due to switching actions; it also provides an on-line algorithm for detection of relay misoperations, which identifies the lines that may be switched back to service after being trip erroneously by a relay.

1. Introduction

Topology switching is a form of power grid control that uses transmission line assets to achieve immediate benefits from rerouting power flows without engaging in re-dispatch action. The switching may be initiated for several unrelated reasons and at different time scales. Economic benefits may be achieved in day-ahead and hour-ahead markets and reliability gains in immediate actions after a major system contingency is detected. While it may appear as a radical step in controlling power systems, the switching has actually been used for many years by utility operators, but it was done on a very limited scale with rather focused aims. Recently, the advanced optimization and computational techniques have been used to formalize the switching sequence selection process automatically, which makes the switching action more timely and robust.

Several papers regarding switching optimization have been published recently. Some are introducing the switching goals, and related optimization means [1]. Others are discussing the applications for the economic gains [2], [3] and some are also exploring the reliability gains [4]. Recent research efforts are aimed at different implementation aspects needed to make this approach an every-day practice [5].

Regarding practical aspects of switching implementation, three important issues have been recognized: a) deterioration of breaker reliability due to more frequent switching actions than currently experienced, b) detection of relay misoperations enabling healthy transmission lines to be recognized as being available to be switched back to operation using an optimization switching study, and c) assessment of relay settings to determine whether they may have to be changed due to the change in the system topology (transmission line interconnectivity).

CB reliability issues may be handled through the on-line condition-based projection of the failure probability, and calculation of the risk associated with operating a given set of breakers involved in a switching sequence. Calculation of the CB failure probability based on measurements of the CB control signals has been reported earlier [6]. The approach is modified and extended to serve the needs of determining most reliable CBs to be involved in a switching sequence and selecting the low risk solution for a reliable switching implementation. In the case of cascading events, relays may trip a transmission line due to misoperation, as reported in the earlier works on detection of cascading event [8-11]. This cascade detection approach has been extended to include a new real-time technique to determine whether a transmission line is still healthy after being tripped by the relay. If so, the tripped transmission line is made available for the restoration switching actions as calculated by the topology switching optimization approach. A fast calculation of relay settings based on the network "tearing" or diakoptics has also been introduced some time ago [7]. This technique was adopted for fast relay setting calculation with a novel approach to determining what might be the settings affected by the switching.

The paper first introduces different aspects of the architecture of a Robust Adaptive Topology Control system, and then discusses the three implementation issues: risk-based assessment of CB operations, detection and classification of relay misoperations, and relay setting calculation and coordination. Conclusions and references are given at the end.

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2. Architecture of the RATC solution

Logical view of the RATC architecture is shown in Figure 1. The solution consists of various analytics components, which can be divided into two main groups:

- Optimization tool – includes implementations of the optimization algorithm, which depending on the objective, calculates the optimal topology and related transmission line switching plan.
- Substation data analytics – mainly utilize the substation data to evaluate the performance and condition of CBs, support identification of cascade events (based on detection of relay misoperation), and recalculate relay settings in accordance with the proposed topology switching.

RATC components require data from various data sources: modeling data tools, market/planning tools, EMS tools (topology processor and state estimator), and substation event-triggered data. Substation data tools provide support to topology control using optimization algorithm. The solution can be used in various scenarios that fall into two groups: a) planning purposes (look-ahead markets); and b) mitigation of unplanned events, such as cascades, sudden drop in renewable generation, or even cyber-physical attacks. Figure 2 illustrates an UML sequence diagram for a look-ahead use of the

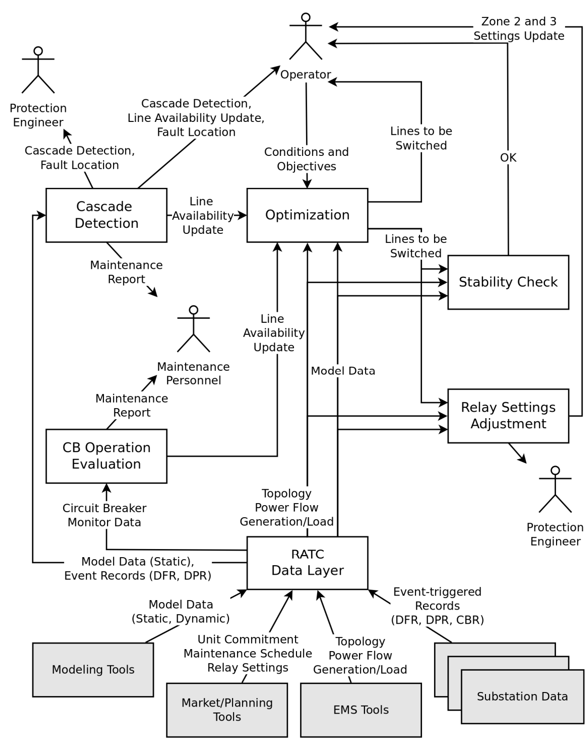


Figure 1. Logical view: RATC solution architecture.

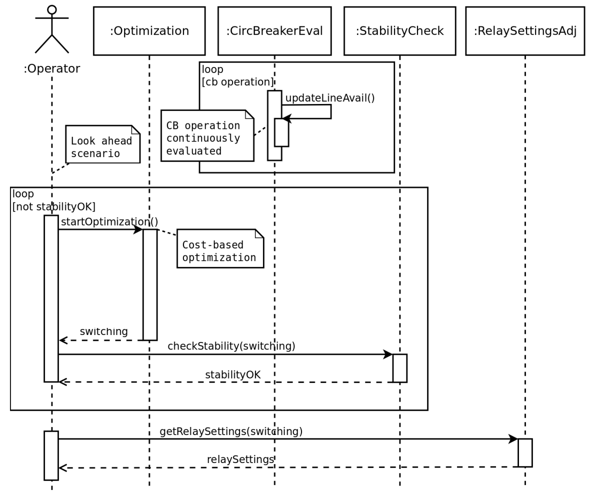


Figure 2. Look-ahead use of the RATC.

RATC solution [12]. CB evaluation component continuously evaluates the breaker condition and updates the line availability (i.e. the lines with unreliable CBs are marked as having too high risk not to be switched). The operator initiates the optimization and sets the objectives. The proposed switching sequence is evaluated for stability, and, if the solution is feasible, the relay settings coordination adjustment module is activated. The outcome indicates the line switching sequence, stability check report, and need to update relay settings. An example for an unplanned event, in this case cascade, is given in Figure 3. Line tripping events are continuously monitored by the cascade detection module, which implements fault detection and classification. The purpose of this module is two-fold: a) to detect relay misoperations, which indicate a potential cascade event, and b) to identify lines that have been falsely tripped and still may be available for restoration. If a possible cascade event is detected, the operator is notified and prompted to run the optimization tools in order to mitigate the incorrect line tripping caused by relay misoperation.

3. Risk-based analysis of circuit breaker operation

CBs are responsible not only for the automated isolation of faulted portions when faults occur and relays issue trip signal, but also for the switching actions and reconfiguration plans when operators demand it. To be able to rely on the system successful operation when a change in its topology is required, one needs to determine how reliable the CBs are. Only then, one can assess the risks associated with a proposed switching scenario.

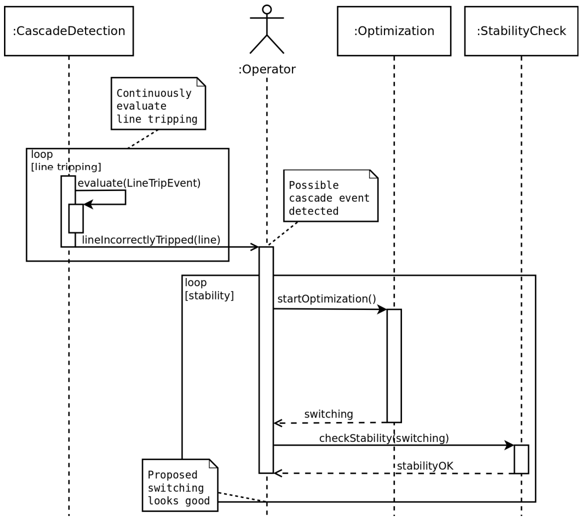


Figure 3. Unplanned event: cascade mitigation.

Otherwise, the optimized switching plan may fail due to the unreliable CBs. While several papers elaborated on condition-based techniques for assessment of CB reliability, no work was done on assessment of the risk of operating breakers based on history of its performance and maintenance regime.

In this regard, a Circuit Breaker Operation Evaluation module has been developed as a part of the substation RATC algorithm. It assesses the risk factors for each proposed switching scenario taking into account the CB reliability and maintenance status so that the operator can decide which switching scenario to select among the multiple optimized switching plans. This helps operators select the switching sequences that are not only optimized but also reliable. In order to evaluate the risk factors, the line switching failure probability and consequence need to be determined. The risk factors are calculated then using a multiplication given below:

$$R_i^t = \sum_{i=1}^{n} P^t(S_i).Con^t(S_i) \tag{1}$$

where R_i^t, $P^t(S_i)$, and $Con^t(S_i)$ are, respectively, the risk factor, failure probability, and consequence assigned to the i^{th} switching plan at time t.

Failure probability of switching a line is assessed in terms of the failure probability of its associated CBs. An approach pursued in this paper continuously assesses the health conditions of the CB by monitoring signals out of the breaker control circuit [15]. The monitored signals of the CB control circuit include the trip coil current, close coil current and contact voltages, as shown in Figure 4. The important timing parameter of each signal is extracted using the internal signal processing module. Then, a probability distribution for each timing parameter is determined. This information is used to determine the performance indices which are used to assess the health condition of the breakers in terms of their failure probability. The proposed procedure and the expected results are demonstrated in Figure 4. The

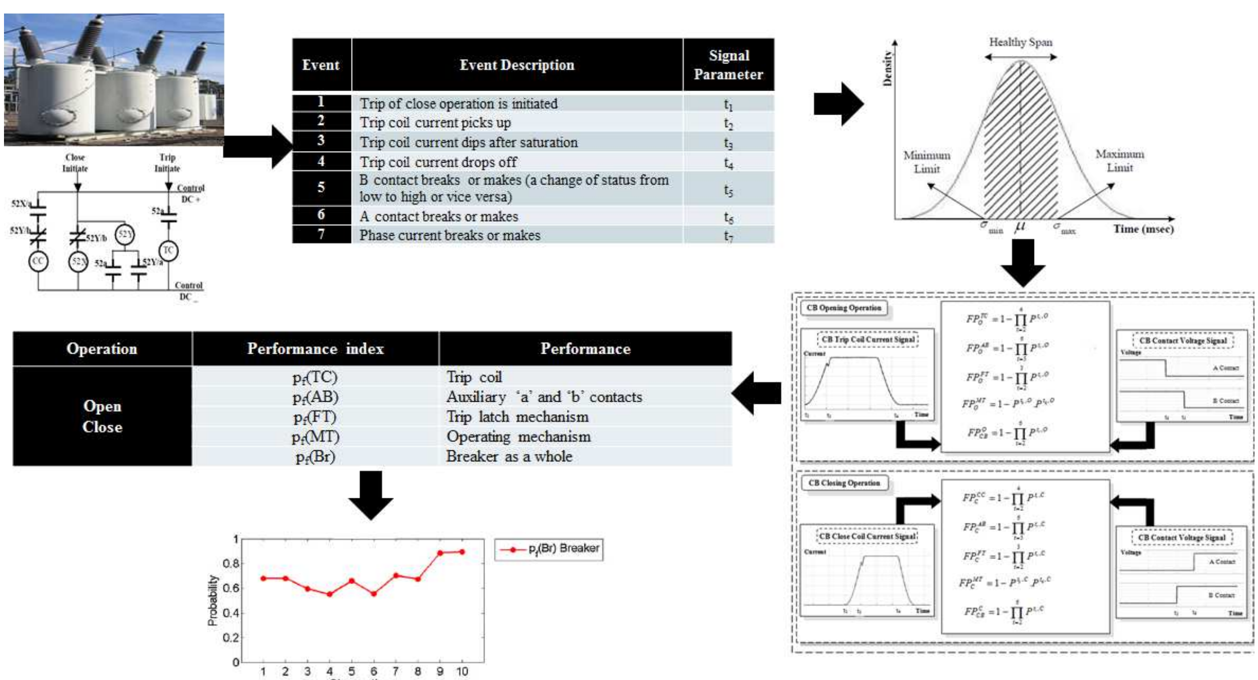


Figure 4. CB Failure probability assessment stage in the Circuit Breaker Operation Evaluation module.

proposed approach is updated as new monitored data comes in [16]. The line availability index, i.e., the failure probability of a switched line, can then be evaluated according to a given substation configuration. Let us take a line connected to the breaker-and-a-half substation configuration depicted in Figure 5, as an example. There are four CBs involved in switching this line. The line opening process involves, opening one CB at a time, at one end of a line, followed by the breakers at the other end. In order to assess the line availability index for the proposed switching action, the failure probability associated with the corresponding CBs (CB1 to CB4) is calculated and the availability index of the line selected for switching can be hence evaluated, as shown in (2).

$$P^t(S_i) = \left(1 - \left(\prod_{i=1}^{4}\left(1 - \mathrm{FP}^t(\mathrm{B}_i)\right)\right)\right) \quad (2)$$

where $P^t(S_i)$ and $\mathrm{FP}^t(\mathrm{B}_i)$ are the failure probability of the i^{th} switching line at time t and the failure probability of the associated CBs. This index for a switching line is being updated since the condition of the associated CBs varies as time progresses and their deterioration/recovery condition changes based on maintenance actions. The procedure continues with the consequence evaluation of each switching action if it fails due to the associated CB mal-operation. It was determined that this can include both technical and economic consequences. The economic aspect taken into account in this paper is expressed as the total generation costs required to optimize the system operation once a switching action is done. The optimized cost, which could be obtained through the switching action and may not be achieved in the case of switching failure due to the CB mal-operation, is regarded as the consequence term in the proposed risk-based framework. With the knowledge on the reliability status of the involved CBs, as explained earlier in Figure 4, as well as the cost consequence

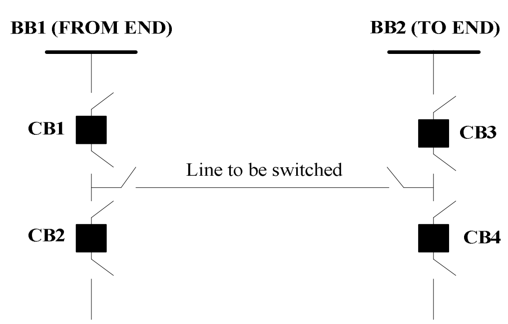
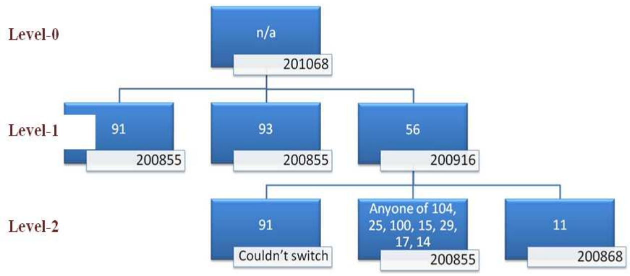


Figure 5. A sample line to be switched in a breaker-and-a-half substation configuration.

term for each switching decision, the cost-based risk factors can be assigned to each switching sequence so that the operator can decide which optimized switching sequence to adopt from the CB health and the sequence overall risk perspectives. The operator may wish to select the switching plan with the lowest amount of risk involved and would be able, as well, to decide which end of the line to start at when initiating the switching actions. The reason for proposing such analysis can be explained through the fact that the CB failure probability is determined based on its health and ability to interrupt the rated or short circuit currents. The line end which has the lowest risk is switched first and the remaining end will have less stress because of the no load switching which is important in the system operation. A sample optimization solution, i.e. an optimized switching tree, is demonstrated in Figure 6. Level-0 is defined as the system base case condition where there is no line switching. The value in white box is the optimal generation cost in dollars obtained from DC OPF with no switching. The objective of the optimization is to achieve the minimum generation cost by switching some of the transmission assets. Level 1 results show the lines that can be switched (for example 91, 93 or 56) and corresponding generation cost. Switching either line 91 or 93 will result in optimal generation cost, so no further switching is possible at this level. Switching line 56 does not provide the optimal cost though. Further switching actions are possible which are shown as Level-2. In this way, a binary tree structure of possible switching sequences is generated. One can observe from Figure 6 that Line 91 has the lowest risk value for switching at two ends of the lines in the first level of the optimization tree. So, this line is the most reliable one among the three proposed options in the first level for the operator to implement the RATC switching solution. The operator concern might be then which end of the line to start the switching action at. The risk values at each end of line 91, shows that the TO END of the line is of lower amount of risk compared to that of the FROM END side. As a result, the operator can start the switching action with the TO END of the line 91. The same explanations can be done for the rest of the switching tree levels which eventually leads to the final switching sequence.



	Failure Probability of the Line	Cost ($)	Normalized Cost Base Cost = $ 201068	Risk
TWO ENDs of line 91	0.029324136	200855	0.998940657	**0.029293072**
FROM END of line 91	0.17567046	200855	0.998940657	0.175484365
TO END of line 91	0.16692696	200855	0.998940657	0.166750127
	Failure Probability of the Line	**Cost ($)**	**Normalized Cost Base Cost = $ 201068**	**Risk**
TWO ENDs of line 93	0.04797055	200855	0.998940657	**0.047919733**
FROM END of line 93	0.58439965	200855	0.998940657	0.58378057
TO END of line 93	0.08208518	200855	0.998940657	0.081998224
	Failure Probability of the Line	**Cost ($)**	**Normalized Cost Base Cost = $ 201068**	**Risk**
TWO ENDs of line 56	0.037110444	200916	0.999244037	**0.03708239**
FROM END of line 56	0.21125034	200916	0.999244037	0.211090643
TO END of line 56	0.17567046	200916	0.999244037	0.17553766

Figure 6. Risk analysis of the RATC optimization results corresponding to the IEEE 73-bus test system.

With the proposed risk analysis framework, one can reduce the risk to RATC which aids the reliable implementation of RATC switching solutions. Circuit Breaker Operation Evaluation activity is continuously taking place in parallel with other activities. Every time a CB operates, this function evaluates conditions of the breakers and, depending on the probability of failure and risks associated with the failure, updates the line availability used by RATC optimization algorithms.

4. Detection and classification of relay misoperations

Lately, transmission lines are expected to operate closer to their power transfer limits, which may increase the chance of cascading events when faults occur [11]. Misoperation of distance relays, the main protective device for transmission line protection, during an un-faulted condition as reported in many of the historical blackouts [12], [13]. Receiving low voltage and high current as inputs by the distance relay during an overload or power swing may cause a false trip in Zone 3 and consequently an outage of a healthy transmission line. This false outage leads to further power system overloads and instability which may finally lead to a complete system black out. Consequently, proposing a simple and accurate fault detection and classification method to detect the relay misoperation and returning the healthy line to service will prevent the above mentioned problem [17], [18].

In this part, an automated fault detection and classification scheme is proposed. As it will be shown next, the method utilizes synchronized voltage and current samples measured at both ends to compute the instantaneous powers on all three phases at two ends of a transmission line to detect and classify a fault. By comparing the direction of measured instantaneous power at two ends, the method is able to identify the occurrence of the fault as well as phases involved in the fault. The method has a significant advantage over the method proposed before [19]. This method of detection and classification does not require high frequency measurement. Furthermore, since computing instantaneous power does not need any averaging or phasor calculation, the method is very fast in detecting and classifying the faults and a reduced post fault data can be used, which is a significant advantage.

A fault detection and classification module has been elaborated as a part of the substation RATC algorithm. Cascading Event Detection module determines the transmission assets, which are currently out of service due to a relay misoperation, that are actually "healthy" and hence candidate to be placed back into service. The classification based on comparisons between instantaneous voltage and current signals demonstrated a very high accuracy in detecting fault or relay misoperation using data from both ends of the line. The general framework is illustrated in Figure 1. The input data to the proposed module includes event records and static model data provided by RATC data layer. These IED event records include three phase voltages and currents from two ends of the line in question as well as the proper channel assignments. The static model data is used to extract the line impedance of the line in question. The output data is mapped into the line availability update (which lines are available for switching). The output will include a fault analysis report. The fault detection and classification method works on comparing the change of sign of magnitudes associated with the instantaneous power computed at two ends of a transmission line using time-synchronized voltage and current samples synchronously measured at both ends. In Figure 7, $V_1(t), I_1(t)$ represents voltage and current measured at one end (Bus 1) of the line at instant t. Similarly

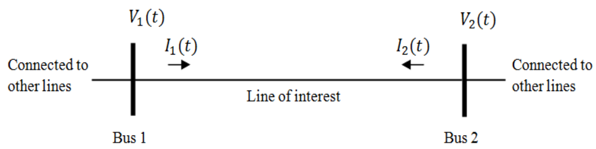


Figure 7. Transmission line with two-end measurements.

$V_2(t), I_2(t)$ represents voltage and current measured at the other end (Bus 2) at the same instant *t*. Currents are measured in the assumed direction shown in Figure 7. All voltage and currents are single phase quantities.

Fault detection and classification module is continuously executing in parallel with other activities. Every time a new set of input data is available in RATC data layer, this function operates, detect whether a relay operated, and determines if the relay operation is correct or not. The calculations are as follows:

- Voltage and currents at bus 1,

$$V_1(t) = V_{1m}\cos\omega t \;,\; I_1(t) = I_{1m}\cos\left(\omega t - \theta_1\right)$$

- Instantaneous power at bus 1,

$$\begin{aligned}
P_1(t) &= V_1(t)\times I_1(t)\\
&= V_{1m}I_{1m}\cos\omega t\cos\left(\omega t-\theta_1\right)\\
&= \frac{V_{1m}I_{1m}}{2}\left[\cos\left(2\omega t-\theta_1\right)+\cos\theta_1\right]\\
&= \frac{V_{1m}I_{1m}}{2}\left[\cos 2\omega t\cos\theta_1+\sin 2\omega t\sin\theta_1+\cos\theta_1\right]\\
&= P_{1m}\left(\cos 2\omega t+1\right)\cos\theta_1+P_{1m}\sin 2\omega t\sin\theta_1
\end{aligned}$$

- Voltage and currents at bus 2,

$$V_2(t) = V_{2m}\cos\left(\omega t-\delta\right), I_2(t) = I_{2m}\cos\left(\omega t-\delta-\theta_2\right)$$

- Instantaneous power at bus 2,

$$\begin{aligned}
P_2(t) &= V_2(t)\times I_2(t)\\
&= V_{2m}I_{2m}\cos\left(\omega t-\delta\right)\cos\left(\omega t-\delta-\theta_2\right)\\
&= P_{2m}\left(\cos 2\left(\omega t-\delta\right)+1\right)\cos\theta_2+P_{2m}\sin 2\left(\omega t-\delta\right)\sin\theta_2
\end{aligned}$$

Now with the assumed direction of currents, magnitude of $I_2(t)$ is negative before fault and positive after fault. For unfaulted situation, instantaneous powers are:

$$P_1^u(t) = P_{1m}^u\left(\cos 2\omega t+1\right)\cos\theta_1^u+P_{1m}^u\sin 2\omega t\sin\theta_1^u$$

$$P_2^u(t) = -P_{2m}^u\left(\cos 2\left(\omega t-\delta\right)+1\right)\cos\theta_2^u-P_{2m}^u\sin 2\left(\omega t-\delta\right)\sin\theta_2^u$$

After fault, instantaneous powers are:

$$P_1^f(t) = P_{1m}^f\left(\cos 2\omega t+1\right)\cos\theta_1^f+P_{1m}^f\sin 2\omega t\sin\theta_1^f$$

$$P_2^f(t) = P_{2m}^f\left(\cos 2\left(\omega t-\delta\right)+1\right)\cos\theta_2^f+P_{2m}^f\sin 2\left(\omega t-\delta\right)\sin\theta_2^f$$

If both before fault and after fault power factor angles are lagging i.e. $\theta_1^u>0, \theta_2^u>0; \theta_1^f>0, \theta_2^f>0$, then $\left|P_1^u(t)\right|>0, \left|P_2^u(t)\right|<0$ before the fault occurs and $\left|P_1^f(t)\right|>0, \left|P_2^f(t)\right|>0$ after fault occurrence hold.

If power factor angles are leading before fault and are lagging after fault i.e. $\theta_1^u<0, \theta_2^u<0;\ \theta_1^f>0, \theta_2^f>0$, then before fault $\left|P_1^u(t)\right|>0$ holds if $\left(\cos 2\omega t+1\right)\cos\theta_1^u>\sin 2\omega t\sin\theta_1^u$ and $\left|P_2^u(t)\right|<0$ holds if $\left(\cos 2\left(\omega t-\delta\right)+1\right)\cos\theta_2^u>\sin 2\left(\omega t-\delta\right)\sin\theta_2^u$ and after fault $\left|P_1^f(t)\right|>0, \left|P_2^f(t)\right|>0$ always holds.

This can be shown in all combinations of lagging and leading power factor angles before and after fault, $\left|P_1^u(t)\right|>0, \left|P_2^u(t)\right|<0$ and $\left|P_1^f(t)\right|>0, \left|P_2^f(t)\right|>0$ if one or some of the inequalities are true:

$$Inequality1:\left(\cos 2\omega t+1\right)\cos\theta_1^u>\sin 2\omega t\sin\theta_1^u$$

$$Inequality2:\left(\cos 2\left(\omega t-\delta\right)+1\right)\cos\theta_2^u>\sin 2\left(\omega t-\delta\right)\sin\theta_2^u$$

$$Inequality3:\left(\cos 2\omega t+1\right)\cos\theta_1^f>\sin 2\omega t\sin\theta_1^f$$

$$Inequality4:\left(\cos 2\left(\omega t-\delta\right)+1\right)\cos\theta_2^f>\sin 2\left(\omega t-\delta\right)\sin\theta_2^f$$

Under small values of power factor angles, all of the inequalities are satisfied. In general, in transmission systems, power factor angles are very small before fault and are lagging after fault, which is sufficient to check:

$\left|P_1^u(t)\right|>0,\ \left|P_2^u(t)\right|<0$ and $\left|P_1^f(t)\right|>0,\ \left|P_2^f(t)\right|>0$.

Therefore, this is a unique feature of instantaneous power under different types of faults which helps to detect and classify faults without using any threshold. This feature is observed only on the faulted phases.

For different types of faults it can be observed that before fault $P_1(t)$ and $P_2(t)$ are in opposite direction while right after fault inception they are in the same direction for the faulty phase. After fault, both fault currents are flowing towards the line making them both positive and this is the reason of change in direction of instantaneous powers at both ends. While both currents and instantaneous powers change direction in the same fashion, instantaneous power are of double frequency than currents and therefore using a smaller window of time is enough to notice the change in direction for the case of instantaneous power. By plotting the difference for each phase, $P\mathrm{sgn}(t)=\mathrm{sgn}(P_1(t))-\mathrm{sgn}(P_2(t))$ holds for phases "a", "b", "c". Theoretically, before fault this difference $P\text{sgn}(t)$ should be ±2 and after fault $P\text{sgn}(t)$ should be 0, but due to transients and the noises present in the measurements, some outliers are present. It is clear from Figure 8 (d-f) that on phase "a", $P\text{sgn}(t)$ becomes almost zero after fault while the other phases remain unchanged. We used this change of difference of sgn() to detect fault instant. We have used a moving window of 5 ms to check whether at least 80% of $P\text{sgn}(t)$ are zero, which indicates phase "a" experienced a fault.

5. Relay setting calculation and coordination

One area that abundance of substation data from IEDs might help is in decision making about the relay settings for different network topologies [20]. Distance relays are considered as the protection choice for the transmission systems. Switching of transmission lines significantly impacts the short circuit levels and hence the apparent impedance seen by the relays for faults in the zone-2 and beyond. It also might affect the normal operation of the network without any fault happening. This happens when, for example, the subsequent network line load flows, following multiple switching actions, cause the load apparent impedance, seen by the relay, gets close to the load margin.

So far, it is not common to change the settings following network topology changes. The proposed relay setting module contains algorithms for checking the adequacy of the existing distance relay settings for the new topology after switching and also performing fast calculation of relay settings for the new topology. This ensures the adequate relay operation after RATC switching actions are implemented in real-time. The interaction of this component with the input and output data can be interpreted from Figure 1. As it is shown in this figure, the relay setting component requires network branch data, topology, power flow, default settings, unit commitment and lines to be switched as the input data. Having prepared this input information, the component calculates the new settings; obviously, zone 1 setting is not probable to change as it is only based on the protected line impedance. So, the focus is on recalculating the zone 2 and zone 3 settings. Having calculated the new settings, one should

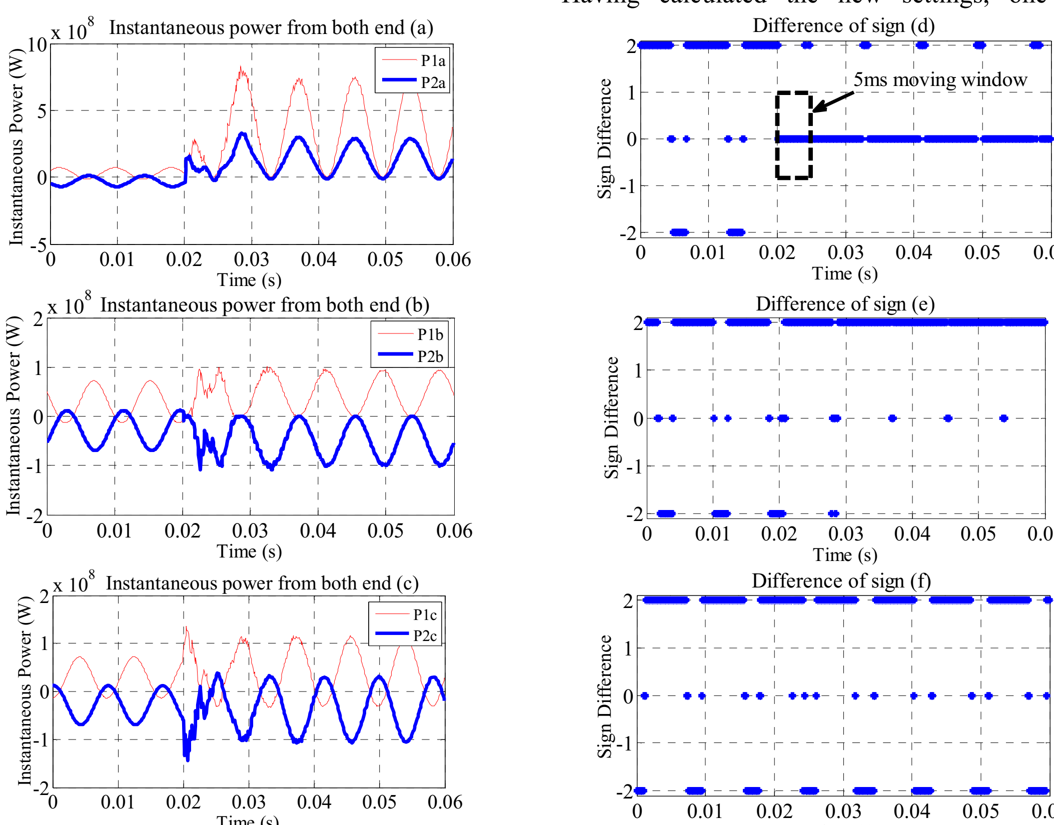


Figure 8. (a-c): $P\text{sgn}(t)$ with respect to time for ag fault; (d-f): $P_1(t)$ and $P_2(t)$ with respect to time for ag fault.

decide whether to apply the new settings or not by comparing with the existing settings. This can be done based on the operator experience.

The distance relay setting and coordination process is a significantly time consuming process. Typically one relay setting change and coordination needs the minimum of 40 working hours in utilities. The time varies depending on the location of the relay which highlights the importance of fast calculation of relay settings for proper selection of relay setting regarding the RATC switching actions. The RATC approach towards the fast calculation of settings is to exploit the parallel computation and sparsity techniques. Considering the time interval between the RATC proposed switching, we believe that using these two techniques, it is possible to recalculate the settings for all the relays very fast.

Short-circuit studies are the major computational component of relay settings calculations. The network admittance matrix (Y_{bus}) is a sparse one which makes sparsity technique as a suitable solution in getting Z_{bus} as Y_{bus} inverse. The time required to obtain Z_{bus} becomes an issue as the system gets larger. In this case, the diakoptics approach might be a proper solution to decrease the calculation time. The basic concept of diakoptics is to analyze a system by tearing the system into smaller sub-systems (Figure 9), solve each sub-system independently, and combine the solutions of the sub-systems with modifications to take the interconnections into consideration. Diakoptics allows parallel computation of sub-system solutions and increases the speed of computation for large systems [21]. It has been observed that diakoptics alone is not sufficient for fast calculation but the sparsity of the underlying system needs also to be effectively utilized. The advantage of diakoptics vanishes as the number of sub-systems increases [7]. So, the approach adopted here is to keep the number of sub-systems to a minimum and use open source parallel sparse solvers effectively within each sub-system for Z_{bus} calculations. To clarify this, let's say we want to obtain the Z_{bus} for a big system. For the first step, we break down the system into, let's say, three sub-systems (Figure 9). We can obtain the Y_{bus} for each sub-system in parallel. As shown in Figure 10, in this method, the system Y_{bus} is re-written as the summation of a sparse block diagonal matrix, which includes the three sub-systems Y_{bus} matrices, and the modification matrix which covers the effect of cut-branches on the whole system [7]. In this equation, Y_{cut} is a diagonal matrix consisting of cut-branches admittances. Now according to Figure 10, we have the system Y_{bus} written in the form of:

$$Y_{bus} = A + XBX^T \tag{3}$$

The following matrix inversion lemma could be used to get the Z_{bus} efficiently without explicit matrix inversion [22]:

$$\begin{aligned} Z_{bus} &= (A + XBX^T)^{-1} = \\ &A^{-1} - A^{-1}X(B^{-1} + X^T A^{-1} X)^{-1} X^T A^{-1} \end{aligned} \tag{4}$$

For each subsystem, sparse LU factorization techniques are used to solve Eq. (4). During the short-circuit studies required for relay setting calculations, several updates to Z_{bus} might be needed for different types of faults. This highlights the importance of avoiding repetitive and excessive calculation of Z_{bus} matrix where it is not necessary. For this purpose, sparsity oriented compensation methods are used [17].

The flowchart of the proposed setting approach is shown in Figure 11. The system is assumed to be divided into three sub-systems through diakoptics approach. Layer-1 calculates Z_{bus} matrix of the whole system using diakoptics. Layer-2 is dedicated for short circuit data base generation. This layer calculates branch currents, voltages and apparent impedance seen by each relay. This layer also computes zone 1 settings as they depend only on the line impedances. The slowest task in all the three

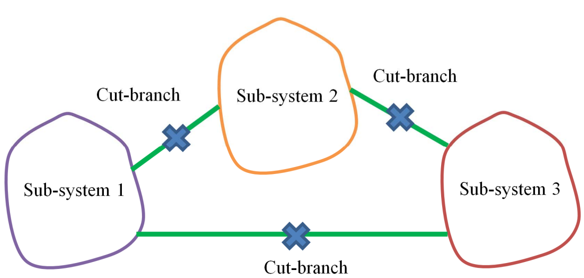


Figure 9. System divided into 3 sub-systems connecting with cut-branches.

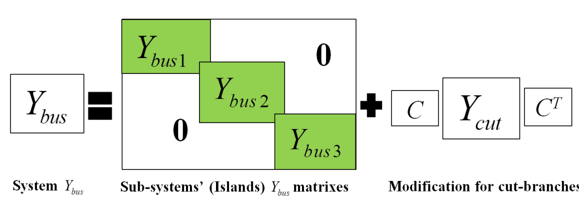


Figure 10. Equation used for system decomposition using diokoptics method.

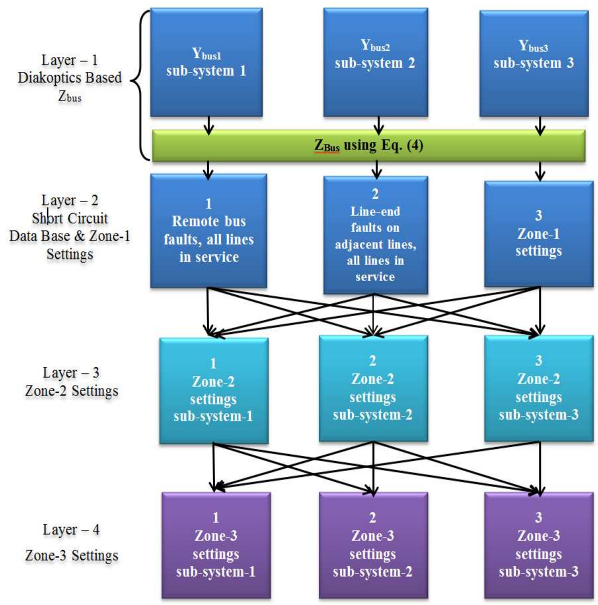


Figure 11. Relay setting module in substation RATC algorithm.

blocks in this layer is the second block where line end faults are calculated, which involves the modification of Z_{bus} for each adjacent line seen by relay. The sub-systems used in Layer-2 do not need to be the same as those used in Layer-1. One can equalize the number of relays to be set in each sub-system so that the computation time will be approximately the same for all. However, there can be differences in computational times depending on the number of adjacent branches seen by each relay. Number of blocks in each layer can be increased based on the size of the network and availability of the computational nodes. Layer-3 calculates the zone 2 settings using the apparent impedances calculated in Layer-2. Layer-4 calculates zone 3 settings. Zone 3 settings depend on the Zone 2 settings of the adjacent relays; this layer needs to be computed after the Layer-3 computation is finished. All the layers have to be sequentially executed. Reduction in computational time of Layer-1 and -2 is most important. So, sparsity and diakoptics based approaches are used in the short circuit calculations.

In this study, the zone setting formulas are the same as the CAPE software default setting procedure for stepped phase distance relays which are [23]:

Zone 1 setting rule:

- Zone 1 Phase = $0.8\times$ min apparent impedance for remote-bus three phase faults;

Zone 2 setting rule:

- Zone 2 Phase = larger of ($1.2\times$ Longest of all zone 1 lines) and (Longest zone 1 line with downstream lines + $0.2\times$ its shortest adjacent line); or
- Zone 2 Phase = $1.2\times$ maximum apparent for faults on the remote bus.

➢ *Note: the larger of the line and apparent impedance is used as final setting for zone 2.*

Zone 3 Setting Rule:

- Zone 3 phase = $1.2\times$ line ohms of longest path to next adjacent bus; or
- Zone 3 phase = $1.1\times$ maximum apparent impedance for faults on next adjacent bus; or
- Zone 3 phase = $1.1\times$ maximum apparent impedance for line-end faults on all adjacent lines;

➢ *Note: the larger of the line and apparent impedance is used as final setting for zone 3.*

The numerical results corresponding to the application of the proposed approach on the IEEE 118 bus system are shown in Table I. This system has been torn into 3 sub-systems when using diakoptics method. The subsystem 1 takes longer time for calculating Y_{bus1}. The total time for diakoptics method, if implemented in parallel, would be 0.068 s, which is the sum of time taken for Z_{bus}, and Y_{bus1}. This time is not so significant for this system but will be more pronounced for larger systems. The comparison between the proposed method and CAPE software in setting all the relays for IEEE 118 shows that there is an opportunity for improving speed of distance relay settings computation significantly by using diakoptics based parallelization and effective sparse matrix solvers. The computational time was reduced from 25.5 seconds using CAPE to .39 seconds using diakoptics.

6. Conclusions

As a result of the study presented in this paper, the following conclusions are reached:

- The paper introduces RATC solution, which takes advantage of the use of substation data

Table I. Z_{bus} Calculation Time with and w/o Diakoptics

	Using Diakoptics Time (s)	**Without Diakoptics Time (s)**
Y_{bus1}	0.019	
Y_{bus2}	0.0014	
Y_{bus3}	0.0015	
Z_{bus}	0.049	0.079
Total Time	0.068	0.079

to improve the system topology control.

- The RATC solution benefits from utilizing the substation data analytics, which improve the decision-making process and overall reliability of the switching
- The CB risk-based assessment gives a choice which sequence to initiate and expect more reliable operation assuring the switching gains. The relay misoperation detection and classification allows the use of the switching optimization to determine how and when to return to service the lines tripped erroneously
- The fast calculation and coordination determines relay settings after the switching sequence has re-configured the lines, and enables change of earlier settings as needed.

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