Dynamic State Estimation-Based Protection: Status and Promise

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Abstract—The introduction of the microprocessor-based numerical relay in the 1980s resulted in multifunctional, multidimensional, communications-enabled complex protection systems for zone and system protection. The increasing capabilities of this technology created new unintended challenges: 1) complexity has increased and selecting coordinated settings is a challenge leading to occasional miscoordination; 2) protection functions still rely on a small number of measurements (typically three voltages and three currents) limiting the ability of protection functions to dependably identify the type of fault conditions; and 3) present approaches are incapable of dealing with hidden failures in the protection system. Statistically, 10% of protection operations are misoperations. This paper presents a new approach to protection that promises to eliminate the majority of the problems that lead to misoperations. The approach is described, demonstrated in the laboratory, compared to traditional protection functions and its application to a substation coordinated protection system capable of detecting and dealing with hidden failures is described. This paper also discusses the planned field testing of the approach.

Index Terms—Power system protective relaying, dynamic state estimation, zone protection, hidden failures.

I. INTRODUCTION

PROTECTION is a ubiquitous function in any power system component to ensure safety of personnel and avoid damage to equipment. Over the years, protection practices have evolved and painted with a remarkable history of innovations and ingenious solutions. Today the multifunctional numerical relay is the centerpiece of all protection schemes. Recent notable advances are: (a) the integration of numerical relays into substation automation architectures and (b) the separation of the data acquisition system from the relays into merging units (MU) and converting the numerical relay into a computing device which receives data from MUs through a process bus. Despite of all the advances, protection reliability remains an issue. Statistically, the industry in the US and abroad is experiencing an average of 10 percent mis-operations. Analysis of relay operation data indicates that contributing factors to protection unreliability are: (a) increased complexity of today's sophisticated protection schemes, (b) reliance of protection functions on limited information (typically a protection function is based on three currents and three voltages), (c) mis-coordination among various protection functions, and (d) inability of present relays and schemes to operate properly when hidden failures occur in the overall protection system including instrumentation. In addition, notwithstanding all the advances, protection gaps still exist, i.e. fault conditions for which there are no reliable ways to detect and protect against, such as drowned conductors in distribution systems, faults near the neutral of solidly grounded systems, and others.

It is apparent that new approaches are needed to deal with the above issues. Substation automation is one promising approach which has the potential of enhancing the information that each relay has access to – more information leads to better characterization of fault conditions and therefore better protection. Substation automation can be one approach that can lead to centralized substation protection. While post mortem analysis approaches have been developed using all relay data to characterize relay performance, there are currently no real time integrated approaches to implement centralized substation protection [17].

This paper presents a recently introduced protection method based on dynamic state estimation (also known as setting-less protection) [1]. The approach has the potential to drastically improve zone protection and integrate the protection of all zones in a substation into a centralized substation scheme with the capability of self-diagnostics, detection of hidden failures and self-healing against hidden failures. We present first the shortcomings of present protection practices and the justification for the proposed dynamic state estimation based approach. The method is presented in its general form followed by specific examples, comparison to legacy protection functions for a few fault events and integration into a centralized substation protection scheme.

Due to lack of space, discussion and examples of present protection technology shortcomings are only restricted to
transformer and line protection. Legacy transformer protection schemes include differential protection, overcurrent protection, volts over hertz, sudden pressure relays and others. One known issue with differential protection is that inrush current flow resembles the condition of an internal fault during energization [2]. As a consequence, differential transformer relays have trouble to distinguish internal fault currents from inrush currents. Harmonic-restrained differential relays were introduced to address this issue [3]–[4]. These relays are based on studies indicating that the second-harmonic component of the inrush current is typically above 15% of the fundamental current, while it is very low for internal faults. Harmonic-restrained differential relays work well for many transformers but unfortunately, the level of second-harmonic component in inrush currents is substantially lower in transformers with improved core steel [5].

In recent years, adaptive differential relays have been studied [6]–[7]. These relays are based on the percentage differential protection scheme, but they can adjust their characteristic automatically according to fault currents. Although the adaptive differential relay can distinguish inrush currents from fault currents, their sensitivities are not high enough to detect internal transformer faults near the neutral of a transformer. In summary, there are protection gaps for transformers.

Legacy transmission line protection schemes include distance protection, directional overcurrent protection, line differential, pilot relaying schemes and others [8]. Non-pilot schemes with legacy distance and directional overcurrent protection functions need complex coordination, cannot simultaneous trip both ends of the line and they are insensitive to high impedance faults. Pilot schemes require communications and so does line differential scheme. Pilot schemes may fail when communications fail. Present line protection schemes may fail to detect high impedance faults [9]. To increase security, pilot protection schemes based on negative sequence have been proposed. These schemes may fail to operate during open-phase conditions or symmetric faults such as three-phase faults [10].

Current differential protection has become one of the most effective protection schemes for transmission lines with the alpha plane method being the most popular. Line differential limitations are: (a) for long lines the capacitive currents force desensitization of the relay [11], (b) loss of communications leads to relay failure, and (c) high impedance faults, especially for long lines, are practically undetectable. In summary, there are protections gaps for transmission lines as well.

Similar discussion can be provided for many other protection zones and legacy protection functions. It is clear that better protection methods are needed.

II. DSE BASED ZONE PROTECTION

The dynamic state estimation based protection (also known as setting-less protection) has been inspired from the differential protection function and can be considered as an extension and generalization as illustrated in Figure 1. In current differential protection the electric currents at all terminals of a protection zone are measured and their weighted sum must be equal to zero (generalized Kirchhoff’s current law). Thus the current differential protection function consists of measuring the sum of the currents and as long as it is zero or near zero no action is taken.

In dynamic state estimation based protection, all existing measurements in the protection zone are utilized. These measurements include: currents and voltages at the terminals of the protection zone, currents and voltages inside the protection zone (as in capacitor bank protection), speed and torque (as in rotating machinery), or other internal measurements including thermal measurements. All above measurements should obey the physical laws for the protection zone (physical laws such as KCL, KVL, motion laws and thermodynamic laws). The physical laws of the protection zone are captured in the dynamic model of the protection zone. This means that in absence of an internal fault (a fault within the protection zone), the measurements would satisfy the dynamic model of the protection zone, i.e., all the physical laws of the protection zone are satisfied. When there is an internal fault, the measurements would not satisfy the dynamic model of the protection zone. This distinction is a powerful, secure and reliable method to identify internal faults and ignore any external faults. A systematic way to verify whether the measurements satisfy the mathematical model is the dynamic state estimation procedure. The resulting method is a Dynamic State Estimation Based Protection (EBP). When an internal fault occurs, even high impedance faults or faults along a coil, the dynamic state estimation reliably detects the abnormality and a trip signal is issued. This basic approach has been presented earlier for specific cases [12]–[14].

The EBP requires a high fidelity mathematical model of the protection zone, the measurements and the dynamic state estimation algorithm. These are presented next.

The model of the protection zone is a set of differential and algebraic equations. In general, the model may include electrical laws, thermal laws and motion laws, i.e., it is a multi-physics model and many times it is a nonlinear model. Our method starts with this model and utilizes a quadratization procedure which reduces any higher order nonlinearities to no more than second order by the introduction of additional variables if necessary (if model is linear or quadratic this process is not needed). This transformation does not change the model. We refer to this model as the Quadratized Dynamic Model (QDM) of the protection zone.

The QDM of the protection zone (device QDM) is provided in equation (1), in terms of through variables \( i(t) \) (terminal currents, voltages, rotational torque, heat rate), and states \( \mathbf{x}(t) \). The model has three sets of equations. The first set of equations is
external equations corresponding to the terminals of the protection zone. The second and third sets of equations are the linear and nonlinear internal equations of the zone, respectively. The device QDM for an example protection zone (power line), is provided in Appendix A.

\[
i(t) = Y_{eqx1}x(t) + D_{eqxd1}\frac{dx(t)}{dt} + C_{eqc1}
\]

\[
0 = Y_{eqx2}x(t) + D_{eqxd2}\frac{dx(t)}{dt} + C_{eqc2}
\]

\[
0 = Y_{eqx3}x(t) + \begin{bmatrix} x(t)^T & F_{eqxx3} \end{bmatrix} x(t) + C_{eqc3}
\]

Next, the measurements are expressed as functions of the protection zone state. The general form is shown in equation (2), where \( z(t) \) is measurements and \( x(t) \) is the protection zone state. Note that these functions may include linear, quadratic and/or differential terms.

\[
z(t) = Y_{zx}x(t) + \begin{bmatrix} x(t)^T & F_{eqzx} \end{bmatrix} x(t) + D_{zx}\frac{dx(t)}{dt} + C_z
\]

Any protection zone model and any measurement in the protection zone can be cast into the above syntax. We have developed models of transformers, lines, capacitor banks, motors, generators and other units in the QDM syntax. Integration of the QDM converts the model into an Algebraic Quadratic Companion Form model (AQCF) [12].

Three alternate algorithms have been implemented and tested for the dynamic state estimation algorithm: (a) Extended Kalman Filter Method Using the QDM; (b) Constraint Optimization Method Using the AQCF; and (c) Unconstraint Optimization Method Using the AQCF. Descriptions of these algorithms have been reported in [13]–[14]. All three algorithms for the dynamic state estimation perform equally well from a statistical point of view. Specifically, numerical experiments show that all three methods provide practically the same estimates and their performance in terms of covariance (uncertainty in the estimated states) are statistically indistinguishable. The results presented in this paper were obtained with algorithm (c). For this reason we provide a concise description of this algorithm.

Algorithm (c): Unconstraint Optimization Method Using the Algebraic Companion Form. This method relaxes the equality constraints and treats them as measurements with a very small error (very small standard deviation). The estimation problem is stated as follows:

Minimize \( J = (h(x) - z(t, t_m))^TW\ (h(x) - z(t, t_m)) \)

where \( W = \text{diag} [..., 1/\sigma_i^2, ...] \), \( \sigma_i \) is the meter error standard deviation including relaxed measurements corresponding to internal constraints. Note that the estimator is the common weighted least squares algorithm. The measurement model is either a linear model, if the protection zone is linear, or a quadratic model. In case of a linear model (for example, transmission line, capacitor bank) the solution is directly obtained (no iterations). In case of quadratic measurement model, the solution is iterative [12]. We have observed convergence within two iterations. This experience is consistent with theory: the solution method is a variation of Newton’s method which has quadratic convergence properties and the measurement models are quadratic. This implies fast convergence.

The estimated states are used to perform the chi-square test to determine the “goodness of fit” of the measurements to the protection zone model. Specifically, the chi-square test quantifies the probability (confidence level) that the residuals (measurements minus model) are distributed within the expected range of meter accuracy. A high confidence level implies that the measurements fit the model and therefore the component under protection is in good health, while a low confidence level implies an internal fault. The EBP relay issues a trip command which includes a user defined intentional delay and a reset time. It is defined as follows:

\[
\text{Trip}(t) = \begin{cases} 1.0 & \text{if } \int_{t-T_{\text{reset}}}^{t} \text{P}_{\text{conf}}(\tau) \, d\tau > T_{\text{delay}} \\ 0.0 & \text{otherwise} \end{cases}
\]

where \( \text{P}_{\text{conf}} \) is the confidence level, \( T_{\text{delay}} \) is the intentional trip delay and \( T_{\text{reset}} \) is the reset time.

The implementation of the DSE based protection is shown in Figure 2. Note we suggest the use of merging units as this technology eliminates instrumentation errors from long control cables and burdens (instrument transformer error is still present). Advantages of the proposed method are: (a) speed (operates on sample values and detects abnormalities and faults within a few samples), (b) detection accuracy, and (c) no need to coordinate with other protection functions. Disadvantages are the complexity of analytics and requirement of accurate dynamic model of the protection zone. The complexity of analytics is transparent to the user. The dynamic model accuracy can be addressed with in-line parameter estimation where the dynamic state estimation is used to determine the correct values of the dynamic model parameters [15].
TABLE I

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive (Negative) sequence Impedance ($z_1$)</td>
<td>$2.2084 + j68.7151 \Omega$</td>
</tr>
<tr>
<td>Zero sequence Impedance ($z_0$)</td>
<td>$60.8966 + j222.4671 \Omega$</td>
</tr>
</tbody>
</table>

Another advantage of the method is its ability to reliably detect hidden failures and replace affected data with estimated values (this is a new capability, not present in any legacy protection systems). The constituent parts of the method are described in more detail in Section IV.

III. NUMERICAL EXPERIMENTS

A number of illustrative examples of specific events are presented. For each one the performance of the EBP is compared to legacy protection functions. The comparison is based on the following criteria: (a) security, (b) dependability, (c) speed, and (d) selectivity. The events have been simulated and the results have been stored in COMTRADE files with 4800 samples per second. The dynamic state estimation execution time is only a fraction of the time of two consecutive samples (416 $\mu$s) using a high end personal computer.

Example Test Case 1: Transmission line protection: The example test system is shown in Figure 3. The line under protection is a 500 kV, 135.22 mile long line. The current rating of the line is 5 kA. The line is protected with the following legacy protection functions: (a) distance protection at side 1, and (b) line differential protection. The settings of these functions are provided below.

Distance protection settings: The sequence parameters of the transmission line are shown in Table I. The selected settings for this relay on the line side are: zone 1: $55.00 \angle 88.16^\circ$ $\Omega$, 0.02 s delay, zone 2: $85.94 \angle 88.16^\circ$ $\Omega$, 0.15 s delay and zone 3: $178.75 \angle 88.16^\circ$ $\Omega$, 0.5 s delay (the impedance settings correspond to 80%, 125% and 260% of the positive sequence impedance, respectively). The compensation factor is $k = (z_0 - z_1)/z_1 = 2.39 \angle -19.05^\circ$.

Line Differential settings: The line differential relay uses the alpha-plane method. The relay trip logic is activated when at least one of the following thresholds is exceeded (a) phase current exceeds 6 kA, (b) zero-sequence current exceeds 500 A, (c) negative sequence current exceeds 500 A. The relay will trip the line when the trip logic is activated and the ratio enters the trip region with a delay of 0.02 s. This process is shown in Figure 4.

For consistency, a 0.02 s delay ($T_{\text{delay}}$) is also used for the EBP relay. The reset time $T_{\text{reset}}$ is selected as 0.05 s.

Event T1: Bolted phase A to neutral internal fault, 10 miles from side 1: A bolted phase A to neutral internal fault occurs at 10 miles from side 1 and time 1.4 s, with 0.01 ohm fault impedance. The results of currents and voltages at both sides of the line are shown in Figure 5.

Distance protection performance: The trace of the impedance “seen” by the relay is shown in Figure 6. We can observe that the impedance enters the zone 1 tripping characteristics at 1.405 s. Therefore, the distance protection will trip this fault at 1.425 s.
Line differential protection performance: The phasor ratio trace of phase A is shown in Figure 7. The other phases are not shown. Along the trace, the character ‘o’ means the thresholds are not exceeded while the character ‘x’ means the thresholds are exceeded. Prior to the fault, the ratio of phase A is near the ideal point (−1, 0), and none of the thresholds are exceeded (with the character ‘o’). During the fault, the ratio of phase A enters the trip region at 1.409 s with the thresholds exceeded (character ‘x’). Therefore, the differential protection will trip the line at 1.429 s.

EBP relay performance: The results are depicted in Figure 8. The first three traces provide the residuals of three-phase currents at side 2. The chi-square values, confidence level and the trip signal are given in the next three traces. The confidence level drops form 100% to 0% immediately when the fault happens and the detection of the fault occurs at 1.4002 s. The line is tripped at 1.4202 s.

Summary of Event T1: For this bolted internal fault, distance protection and line differential protection correctly detect the fault at times 1.405 s and 1.409 s respectively, and trip the line at times 1.425 s and 1.429 s respectively; the proposed EBP relay detects the internal fault at 1.4002 s and trips the line at 1.4202 s.

Event T2: High impedance (300 ohm) phase A to neutral internal fault, 65 miles from side 2: A high impedance phase A to neutral internal fault occurs at 65 miles from side 2 and time 1.4 s, with 300 ohm fault impedance. The results of currents and voltages at both sides of the line are shown in Figure 9.

Distance protection performance: The trace of the impedance “seen” by the relay is shown in Figure 10. We can observe that the impedance stays outside the tripping characteristics during the fault. Therefore, the distance protection does not detect this fault.

Line differential protection performance: The phasor ratio trace of phase A is shown in Figure 11. The other phases are not shown. During the fault, none of the thresholds are exceeded and the ratio of phase A still remains inside the restraint region. Therefore, the differential protection does not detect this fault.
EBP relay performance: The results are depicted in Figure 12. The confidence level drops from 100% to 0% at time 1.4002 s. Therefore, EBP detects the fault at 1.4002 s. The line is tripped at 1.4232 s.

Summary of Event T2: For this high impedance internal fault, distance protection and line differential protection do not detect the fault; the proposed EBP relay detects the fault at 1.4002 s and trips the line at 1.4232 s.

Event T3: High impedance (300 ohm) phase A to ground internal fault, 65 miles from side 2, with the loss of one side current measurements: The fault in event T3 is the same as that in event T2, but without three-phase current measurements at side 1 of the line due to loss of communications.

Distance protection performance: The performance is exactly the same as shown in Figure 10 since distance protection does not need any communications.

Line differential protection performance: It cannot detect this internal fault with loss of communications. It has been also shown that it does not detect this fault even with operational communications.

EBP relay performance: The results are shown in Figure 13. The confidence level drops from 100% to 0% at time 1.4002 s. Thus, the fault is detected at time 1.4002 s. The trip signal is issued at 1.4218 s.

Summary of Event T3: For this high impedance internal fault with the loss of one side current measurements, distance protection and line differential protection do not detect the fault; the proposed EBP relay detects this fault at 1.4002 s and trips the line at 1.4218 s.

Example Test Case 2: Transformer Protection: The example test system comprises a 750 kVA 7.98 kV/0.277 kV single-phase saturable-core transformer, designated as T1 in Figure 14. The transformer is protected with two legacy protection functions: (a) harmonic-restraint differential protection and (b) time-overcurrent. The performance of the legacy protection functions is compared to the performance of the EBP relay. The legacy protection functions have the following settings: (a) harmonic-restraint differential protection: the percent differential setting is 20%, the minimum pickup operating current is 5 A (referred to primary side, i.e. 21.2%); (b) time-overcurrent protection: the pickup current refer to primary
Fig. 15. Results of an energization followed by a turn to neutral fault at secondary side.

Fig. 16. Harmonic-restraint differential protection results of an energization followed by a turn to neutral fault at secondary side.

The transformer is de-energized and it is switched in at time $t = 6.4$ s. At time $t = 6.45$ s, a turn to core fault occurs on the secondary side of transformer, 5% from transformer neutral. The terminal voltage and current results for this event are shown in Figure 15. Note that moderate inrush current exists at the primary side terminal.

Harmonic-restrained differential protection performance: The results for harmonic-restrained differential protection are shown in Figure 16. When the transformer is switched in, the operating current is about 90A, which is above the minimum pick-up setting (5A). The differential percent is about 160%, which is also above the threshold setting. The 2nd harmonic level is about 35% (above the 20% setting), so that the differential algorithm blocks any trip decision during energization. When the turn-neutral (at 5%) fault happens, the operating current is about 60A, which is above the minimum pick-up setting (5A). The differential percent is about 120%, which is also above the threshold setting. However, the 2nd harmonic level is about 25% and it is still above the setting. The differential algorithm blocks the trip decision for this internal fault. As a consequence, the harmonic-restrained differential protection fails to protect the transformer for this event.

Time-overcurrent protection performance: The results for time-overcurrent protection are shown in Figure 17. During the energization and following internal faults, the RMS value of primary terminal current is within $50 \sim 101$A, which is below the threshold setting (140A). As a consequence, the time-overcurrent protection fails to protect the transformer for this event.

EBP relay performance: The EBP relay results are shown in Figure 18. Upon energization, there is very little change in the chi-square value and the confidence level stays at 100% (with few oscillations). The EBP relay asserts that during energization the transformer operates normally (unfaulted). When the internal fault happens, the confidence level drops from 100% to zero at time 6.4502 s. Thus the EBP relay detects the fault at 6.4502 s and trips the transformer at 6.4702 s.

Summary of Event X1: For this turn-to-neutral internal fault during transformer energization, harmonic-restraint differential protection and time-overcurrent protection do not detect the
fault; the proposed EBP relay detects the fault at 6.4502 s and 
trips the transformer at 6.4702 s.

Multiple other events are presented in the references. For 
e.g., reference [12] presents among other cases, external to 
the protection zone bolted fault which generates high currents 
in the unfaulted zone. We have also tested the method with 
hardware in the loop (OMICRON amplifiers, Merging Units 
(GE, SIEMENS, REASON). The amplifiers and merging units 
generate errors similar to those that may be encountered in 
the field. The method consistently performed dependably and 
secure. In addition, we have not encountered any algorithmic 
instability.

IV. HIDDEN FAILURES DETECTION AND HANDLING
The EBP as described assumes that there are no hidden fail-
ures that corrupt the streaming measurements with errors. Dis-
crepancies between measurements and the dynamic model of 
the protection zone are due to internal faults.

In case of hidden failures, the measurement data will be cor-
rupted. This condition must be detected and corrected. We have 
developed two approaches to detect and correct for hidden fail-
ures. The two methods are complementary and increase the 
dependability and security of the EBP method.

Approach 1: This method first estimates the approximate fault 
location and type. This is achieved by analysis of the measure-
ment data. Subsequently, the dynamic model of the protection 
zone is altered to represent the fault. In general, this introduces 
additional parameters, such as distance to the fault and fault ad-
mittance). These parameters are entered as unknown states to be 
estimated by the dynamic state estimator. There are two possible 
outcomes of the dynamic state estimator: (a) the measurements 
fit the faulted protection zone model with high confidence level; 
this indicates that there are no hidden failures and there is indeed 
an internal fault in the protection zone. (b) the measurements do 
not fit the faulted protection zone model; this indicates that there 
may be bad data due to hidden failures and there may be or may 
not be an internal fault. The question is settled with the second 
approach described next. Due to space limitation we skip the 
math details of this approach.

Approach 2: In this approach we use redundant measurements 
to identify the source of the bad data (hidden failures, internal 
failure or combination). Redundant data can be used within the 
EBP as in most cases there is redundant instrumentation for 
protection zones, for example multiple CTs at the terminals of 
power equipment, and multiple VTs at buses or terminals of 
equipment. We have elected to use the redundancy of the entire 
substation because this approach provides a unified and more 
reliable approach to detecting hidden failures and removing 
their effects due to the large redundancy in measurements in a 
substation. A brief description follows.

Consider a substation with \( n \) protection zones (lines, trans-
formers, busses, capacitors, etc.) and each protection zone is 
protected with an EBP relay as shown in Figure 19. Each EBP 
relay is supervised by the Centralized Substation Protection 
(CSP) which receives all the data from all the EBP and per-
forms a substation wide dynamic state estimation. Specifically,
the EBP relays provide the input to the substation wide dynamic 
state estimation which employs analytics and a logic that deter-
mines with computable certainty the following: (a) all data are 
valid i.e. no instrumentation errors, no hidden failures or (b) 
bad data are present in which case an identification process is 
initiated to determine the root cause of the bad data. In case of 
(a), the centralized substation protection simply acts as a super-
visor and endorses the decisions by the individual EBP relays 
for each one of the protection zones. In case of (b), the root 
cause is identified and there are two possibilities. Possibility 1: 
the root cause is automatically corrected, for example in case of 
a wrong CT ratio entry, the CSP will automatically change 
the CT ratio in the data base to the correct value. Possibility 
2: in case that the root cause cannot be automatically corrected 
and requires human involvement (for example a blown fuse), a 
diagnostic/alarm is issued and displayed at the substation hu-
man interface as well as sent to the control center. At the same 
time the corrupted data are replaced with estimated values using 
the substation real time estimated model and the replaced data 
are sent to the EBP relays. This enables continuous and reliable 
operation of the EBP relays, even in the presence of hidden 
failures. This capability does not exist in present technology.

Note that at the substation layer, a typical 2000% measure-
ment redundancy exists (redundancy = (number of measure-
ments/number of states) \times 100\%), which enables the dynamic 
state estimation to detect and identify bad data that may result 
from hidden failures, human error or modeling errors [16].

An example of hidden failure detection identification and 
replacement of compromised data is briefly presented here. The 
substation single line diagram and the CTs and VTs for this
substation state estimator performs a hypothesis testing, i.e. the three voltage measurements from this VT are removed and the state estimator is executed again yielding an average difference between measurements and model of 0.21%. It is concluded that the VT data have been compromised and they are replaced with estimated values. Because the computational process in this case takes 0.75 cycles, the replaced data start 0.75 cycles after the fuse is blown and are fed to the EBP relay. The received sampled values at the EBP relay are shown in Figure 21(b). While the EBP relay detects an abnormality for about 0.75 cycles, once the data have been replaced, the EBP relay resets and no action is taken.

The substation state estimator also issues a diagnostic that reports a VT malfunctioning and identifies the VT and the time the malfunctioning occurred.

V. Conclusion

The proposed dynamic state estimation based protection has the potential of providing dependable and secure protection. The proposed EBP relay has been compared to legacy protection schemes and for specific fault events the EBP has dependably and securely identified faults while legacy functions failed. The EBP relay speed is much faster than legacy protection since faults are detected within a few samples of measurements, i.e. sub-millisecond response time. The proposed EBP relay requires an accurate model of the protection zone and as accurate as possible measurements. The model is typically known. Model parameters that may be suspected of inaccuracies, can be estimated in real time by the dynamic state estimator. The measurement accuracy depends on the instrumentation. The use of merging units provides much more accurate measurements since the errors introduced by long instrumentation cables, and other components in the instrumentation channel are removed. Finally, the results from the EBP relays are used in a substation wide state estimation to provide validation of measurement data or to detect hidden failures, correct the source of errors or alert operators of the problem in case human correction is needed. In any case, corrupted data are replaced with estimated values enabling reliable protection even in the presence of hidden failures.

Appendix A

This Appendix provides example device Quadratized Dynamic Model (QDM) of transmission line. The QDM has the same syntax as shown in equation (1).

The line is modeled as a multi-section circuit, each section is represented as a \( \pi \)-equivalent short line model. Figure A-1 depicts the \( \pi \)-equivalent model of section \( k \), with series resistance matrix \( R \), series inductance matrix \( L \), shunt conductance matrix \( G \), shunt capacitance matrix \( C \), three phase voltages \( v_k(t) \), \( v_{k+1}(t) \), and three phase currents \( i_{ak}(t) \), \( i_{bk}(t) \). The number of sections is selected in such a way that the travel length of electro-magnetic waves in one sampling interval is comparable to the length of each section.
The QDM of section \( k \) is:

\[
\begin{align*}
    \mathbf{y}(t) &= \begin{bmatrix} \mathbf{i}_{k1}(t) & \mathbf{i}_{k1}(t) \end{bmatrix}^T, \\
    \mathbf{x}(t) &= \begin{bmatrix} \mathbf{v}_1(t) & \mathbf{v}_{k+1}(t) & \mathbf{i}_{Lk}(t) \end{bmatrix}^T, \\
    Y_{eq1} &= \begin{bmatrix} 0 & I & 0 \\ 0 & G & -I \end{bmatrix}, \quad D_{eq1} = \begin{bmatrix} C & 0 & 0 \\ 0 & C & 0 \end{bmatrix}, \\
    Y_{eq2} &= \begin{bmatrix} -I & I & R \end{bmatrix}, \quad D_{eq2} = \begin{bmatrix} 0 & 0 & L \end{bmatrix},
\end{align*}
\]

where \( I \) is the identity matrix, and all other vectors and matrices are null.

### References


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