Case Study: Centralized Ground Fault Detection System for LADWP Ungrounded Distribution System

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***Abstract*—A typical Los Angeles Department of Water and Power (LADWP) distribution substation consists of two or more buses, two or more transformer banks, and multiple feeders that can be connected to any bus at any time. Voltage signals for protection purposes are measured at the banks, not at each individual feeder. This makes detecting ground faults on the LADWP 4.8 kV ungrounded power system a daunting task because there is no direct correlation between the zero-sequence voltage ($3V_0$) of the banks or buses and the zero-sequence current ($3I_0$) of the feeders. Presently, if the $3V_0$ magnitude of one of the banks is above a preset threshold, that $3V_0$ voltage is switched to all the feeder relays in the substation whether they are connected to the same bus as the faulted feeder or not. The problem with the present scheme is that if a feeder is not associated with the faulted feeder and has a $3I_0$ value above the preset threshold, the scheme may declare the direction of the $3I_0$ flow as forward, indicating that the fault is on that feeder. This has resulted in multiple feeders being declared as faulted. To identify the actual faulted feeder, the line crew has to isolate each of the suspected feeders.**

This paper briefly explains the ground fault detection of ungrounded distribution systems and innovative algorithms developed to identify ground faults, as well as laboratory test and staged-fault field test results.

The paper describes a centralized ground fault detection system for ungrounded distribution systems.

I. Introduction

The Los Angeles Department of Water and Power (LADWP) has met the electrical needs of the ratepayers of Los Angeles and Owens Valley for over a century. This supply of electricity has played an important role in the development of the communities LADWP serves, helping them become home to one of the most diverse populations in the world. LADWP is coming to a crossroads in charting their course for the twenty-first century. Far-reaching decisions are being implemented that will transform the sources and the way electric power is delivered for decades to come. The commitment to providing safe, reliable, sustainable, and reasonably priced electricity for the future will lead to a stronger, greener, and more prosperous living environment for all LADWP ratepayers.

Maintaining continuity of service has always been important. Equally important is safety, and the detection of ground faults in the LADWP 4.8 kV delta distribution system has always been a challenge. For 50 years, a simple $3V_0$ detection system identified when there was a ground fault somewhere on a feeder circuit within the 120 distribution substations throughout the power system, but it required substation operators to manually switch circuits to pinpoint which circuit had the ground condition. This process was slow and prone to safety concerns. The current scheme, although an improvement to the simple $3V_0$ scheme, is prone to error and struggles with accurate detection. Implementation of the scheme described in this paper gives the ability to accurately detect which feeder has the ground fault, thereby improving the quality of service to LADWP customers and the safety of the power system.

II. Ground Fault Detection in Ungrounded Power Systems

LADWP operates and maintains a 4.8 kV ungrounded power system in the Los Angeles, California, area. The reason for selecting an ungrounded power system is to enable the power system to continue operating in the presence of a single-phase-to-ground (SLG) fault. However, for safety reasons, LADWP wants to be able to detect and isolate single-phase faults on the power system as soon as possible. To this end, they want to identify the faulted feeder accurately and rapidly so that line crews can quickly be dispatched to patrol the faulted feeder.

In an ungrounded power system, loads are connected phase-to-phase and, as such, there are no intentional ground connections on the system. That means that under normal system operating conditions, there is no zero-sequence current or zero-sequence voltage present (if we assume that the power lines are perfectly transposed). Therefore, any contact between a phase conductor and ground is going to result in zero-sequence current flowing, with the capacitance-to-ground of the unfaulted phase conductors providing the return path. The flow of zero-sequence currents for an SLG fault in an ungrounded power system is shown in Fig. 1.

The presence of zero-sequence voltage ($3V_0$) in the power system results in the flow of zero-sequence current ($3I_0$) in the power system. Using the relationship between the zero-sequence voltage and the zero-sequence current, the faulted feeder can be identified [1] [2].

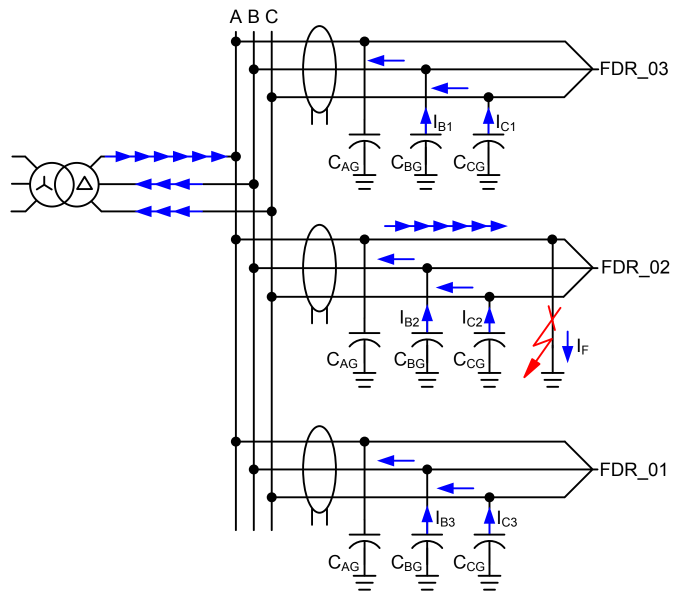

Fig. 1. Fault current flow in an ungrounded power system for an SLG fault on the system.

The zero-sequence current is known as the operating quantity and the zero-sequence voltage is known as the polarizing quantity of the zero-sequence directional element. By comparing the angular difference between the operating quantity and the polarizing quantity, the faulted feeder in the power system can be determined. For an SLG fault in front of the relay measuring point, the $3I_0$ current lags the $3V_0$ voltage by an angle ranging from 90 to 180 degrees, depending on the fault resistance [2] [3]. For a solid fault (fault resistance $\approx$ 0), $3I_0$ lags $3V_0$ by approximately 90 degrees and, as the fault resistance increases, $3I_0$ lags $3V_0$ by a greater angle, up to a theoretical limit of 180 degrees. For an SLG fault behind the relay measuring point, the $3I_0$ current leads the $3V_0$ voltage by an angle between 0 and 90 degrees [2] [3]. For a solid SLG fault behind the relay measuring point, $3I_0$ leads $3V_0$ by approximately 90 degrees, but as the fault resistance increases, the angle by which $3I_0$ leads $3V_0$ decreases until it reaches a theoretical limit of 0 degrees.

Therefore, as shown in Fig. 2, if $3I_0$ lags $3V_0$ by 90 to 180 degrees, then the fault is in front of the relay measuring point. If $3I_0$ leads $3V_0$ by 0 to 90 degrees, the fault is behind the relay measuring point. Because most of the feeders in an ungrounded power system are radial, the faulted feeder is the one in which the $3I_0$ current lags the $3V_0$ voltage.

Examining Fig. 2, we could assume that identifying the faulted feeder on an ungrounded power system does not seem to be too challenging. So what is unique about the LADWP ungrounded power system that makes determining the faulted feeder so difficult?

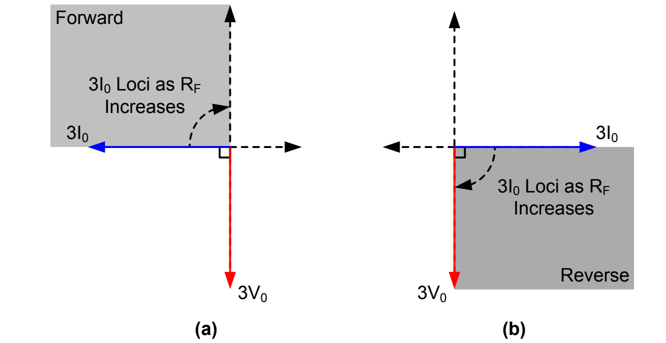

Fig. 2. The relationship between the zero-sequence voltage ($3V_0$) and the zero-sequence current ($3I_0$) for a forward fault (a) and a reverse fault (b) on an ungrounded power system.

A. *Problem Description*

A typical double busbar substation arrangement for the LADWP ungrounded power system is shown in Fig. 3.

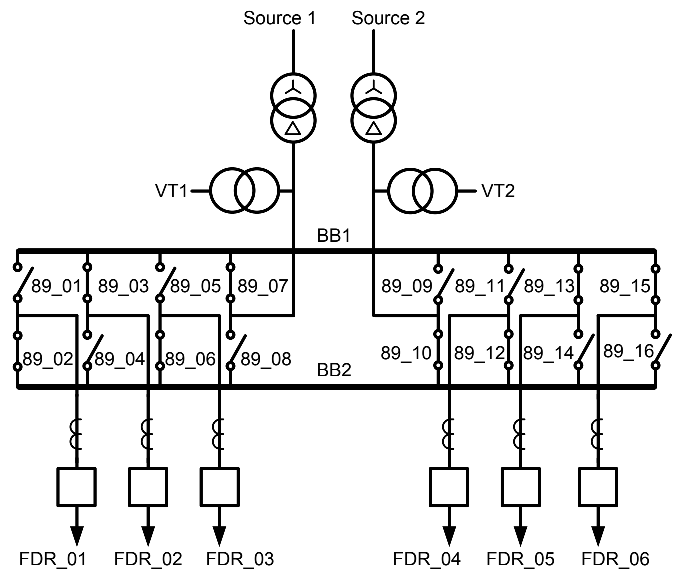

Fig. 3. Typical double busbar arrangement for an LADWP substation on the ungrounded power system.

From Fig. 3, we can see that the transformers and the feeders at the substation can be linked to any one of the two busbars (BB1 or BB2) at any time. This means that the corresponding $3V_0$ voltage needed to polarize the $3I_0$ current of a particular feeder during an SLG fault on the power system cannot be readily determined beforehand. If the status of the feeder and transformer isolator switches (89_*nn*) were known, then this would be a trivial task. Using the status of the feeder and transformer isolator switches and some simple logic, the correct $3V_0$ voltage can be routed to each feeder relay at the substation at any time. However, there is no auxiliary contact available on the isolator switches to indicate the position (status) of the isolator switch on this power system.

To overcome the issue of not knowing which feeder was connected to which busbar and which $3V_0$ voltage to route to which relay, the original protection designers proposed the following solution:

- Route all of the $3V_0$ voltages at a substation into a programmable logic controller (PLC).
- Have the PLC determine which of the $3V_0$ voltages has the highest magnitude.
- If the magnitude of a particular $3V_0$ voltage is above a set threshold, route that $3V_0$ voltage to all feeder relays in the substation to use as the polarizing voltage for the $3I_0$ current measured by that relay.

In a perfect world, there would be nothing wrong with this logic because the scheme would pair the correct $3V_0$ voltage with the $3I_0$ current of the faulted feeder. However, the feeders on the LADWP 4.8 kV network are not perfectly transposed, resulting in unequal phase-to-ground capacitance. This results in a standing zero-sequence current on the feeders and power system. Loads (motor loads in particular) typically have an unequal phase-to-ground capacitance and exacerbate the problem by creating additional standing zero-sequence currents, thereby increasing the standing zero-sequence current in a particular feeder and the power system as a whole. To understand the shortcomings of the original protection concept for the LADWP 4.8 kV ungrounded power system, we assume the following for a double busbar substation:

- Half of the feeders are connected to Busbar 1 (BB1), as shown in Fig. 3, and the other half are connected to Busbar 2 (BB2).
- Transformer 1 supplies BB1 and Transformer 2 supplies BB2.
- If a feeder connected to BB1 experiences an SLG fault, then the $3V_0$ voltage measured by VT1 will have a higher magnitude than the $3V_0$ measured by VT2. Therefore, the $3V_0$ voltage measured by VT1 will be routed to all relays at the substation, even the relays not connected to BB1.

The result is that for all the relays connected to BB1, only the feeder that has the fault on it will declare the fault in the forward direction. All other feeders will declare the fault in the reverse direction. However, for the relays connected to BB2, there are feeders that have a standing $3I_0$ current. If the PLC routes the $3V_0$ voltage from the faulted busbar to the relays on these feeders, there is a possibility that the relays on these unfaulted feeders will declare a forward ground fault. Remember that there is no correlation between the $3I_0$ on the feeders connected to the unfaulted busbar and the $3V_0$ of the faulted bus because these are two independent power systems. If the angular relationship between $3I_0$ from one or more feeders connected to the unfaulted bus and the $3V_0$ from the faulted bus is such that $3I_0$ lags $3V_0$ by between 90 to 180 degrees, the relay or relays connected to the feeder or feeders will declare a fault in the forward direction, effectively indicating that these are faulted feeders.

The problem with the original design is not identifying the faulted feeder, but rather identifying the feeders that are not connected to the faulted bus that are declaring themselves as faulted feeders. From an operational point of view, line crews need to be dispatched to each of the indicated faulted feeders in order to find the correct one. This is a waste of resources and is time-consuming, so a better solution for determining the faulted feeder in the LADWP 4.8 kV ungrounded power system was investigated.

B. *Possible Solution*

To explore a possible solution for this particular problem, we take a typical 4.8 kV LADWP substation with the feeders and transformers connected as shown in Fig. 4. Assume FDR_05 experiences an SLG fault.

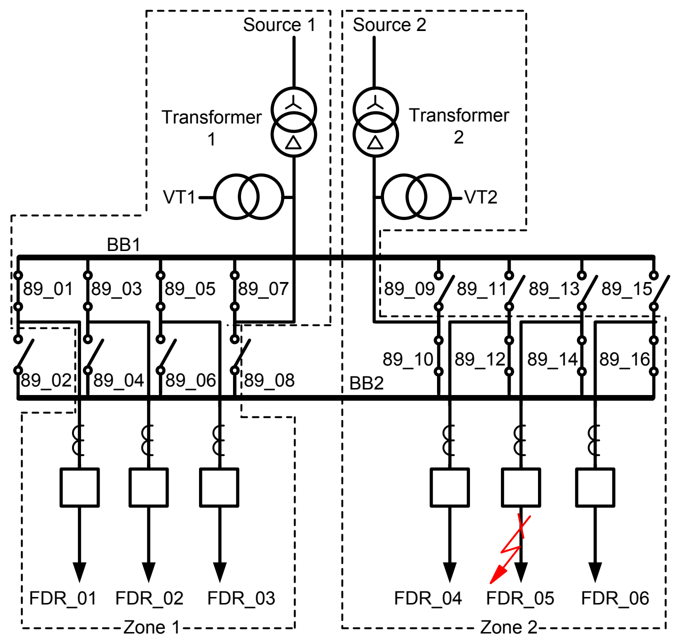

Fig. 4. Bus connections for a typical LADWP substation on the ungrounded power system, with an SLG fault on FDR_05 in Zone 2.

Once we have grouped all of the feeders (FDR_*nn*) and transformers that are connected to BB1 in Zone 1 and BB2 in Zone 2, we observe the behavior of the $3I_0$ currents and $3V_0$ voltages in the two zones before and during an SLG fault condition on FDR_05.

For Zone 1, the $3I_0$ currents and the $3V_0$ voltages before and after the fault remain pretty much the same, so Zone 1 does not experience any noticeable change in the $3I_0$ current or the $3V_0$ voltage. Fig. 5 shows the standing $3I_0$ current and $3V_0$ voltage for Zone 1 (the unfaulted zone) before and during the SLG fault on FDR_05.

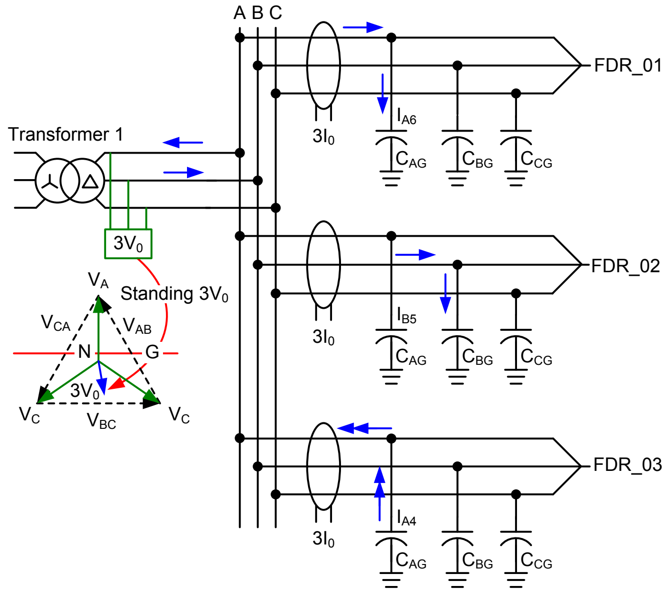

Fig. 5. Zero-sequence current flow due to system unbalances in Zone 1 (the unfaulted zone) before and during the SLG fault on the power system.

We now examine what happens to the $3I_0$ currents and $3V_0$ voltages in Zone 2. The prefault conditions of Zone 2 look very similar to that of Zone 1 (shown in Fig. 5). There is some standing $3I_0$ current and $3V_0$ voltage in the power system prior to the fault, but when the SLG fault occurs, there is a significant incremental change in $3I_0$ and $3V_0$ in the faulted zone. Fig. 6 shows the $3I_0$ current and the $3V_0$ voltage in Zone 2 during the SLG fault on the power system.

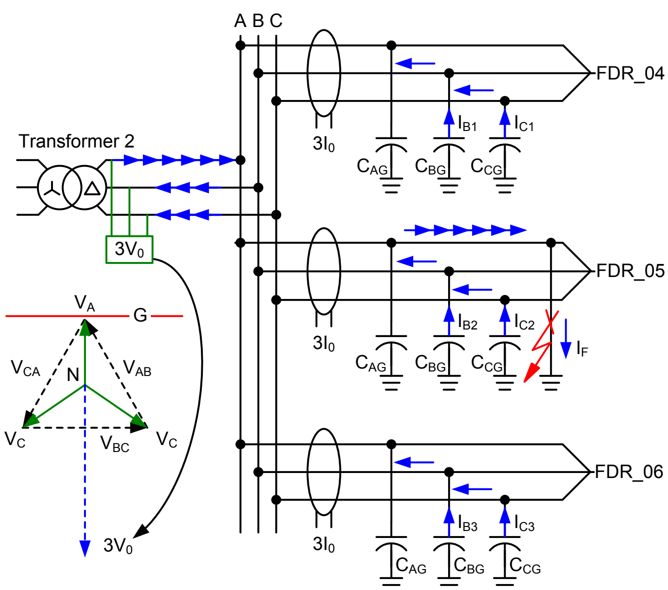

Fig. 6. Zero-sequence current flow in Zone 2 (the faulted zone) during the SLG fault on FDR_05.

An incremental change in the $3I_0$ current can be used to determine whether a feeder is connected to the faulted zone. All of the feeders connected to the faulted zone will experience a significant incremental change in their $3I_0$ current magnitudes. The $3V_0$ voltage used to polarize the directional element associated with each of the faulted feeders will be the $3V_0$ voltage that experienced the most significant incremental change. In this manner, the faulted feeders and the correct voltage with which to polarize the directional elements are identified.

Each feeder has its own protective relay that calculates the $3I_0$ current in the feeder, so it is possible to have each relay monitor the incremental change in $3I_0$ for the feeder it is protecting. However, a typical feeder protection relay has only one set of voltage inputs, so to route the correct $3V_0$ voltage to each protective relay would require an external processing unit with built-in logic capability. Instead, it would be better to realize the previously mentioned solution in one central unit (CU), where the $3I_0$ currents from all of the feeders in the substation and all of the $3V_0$ voltages are input.

The remainder of this paper explores the solution of implementing centralized substation ground fault detection in an ungrounded power system.

III. The Central Unit

With all of the $3V_0$ busbar voltages and $3I_0$ feeder currents at a substation input to a central location, the process of identifying the faulted feeder can begin. The steps of identifying the faulted feeder are as follows:

- Identify which feeders are suspected to be faulted. This is done by identifying which feeders experienced an incremental change in their $3I_0$ current. We refer to these feeders as the faulted zone.
- Identify which $3V_0$ busbar voltage is associated with the faulted zone, and use this $3V_0$ voltage as a reference voltage.
- Calculate the incremental torque generated because of the SLG fault for all of the feeders in the faulted zone using the reference voltage.
- Determine the faulted feeder(s) using the calculated incremental torque quantities.

To determine which feeders are in the faulted zone, we need to determine which feeders experienced an incremental change in their $3I_0$ current due to the SLG fault. The incremental logic compares the present value of $3I_0$ against a previous value of $3I_0$, typically from five to six cycles ago. If the difference between the present value and the previous value is above a dynamic threshold, the incremental logic asserts an output that indicates the feeder experienced a notable change in its $3I_0$ value and is therefore in the faulted zone.

A simplified sketch of the incremental $3I_0$ logic is shown in Fig. 7.

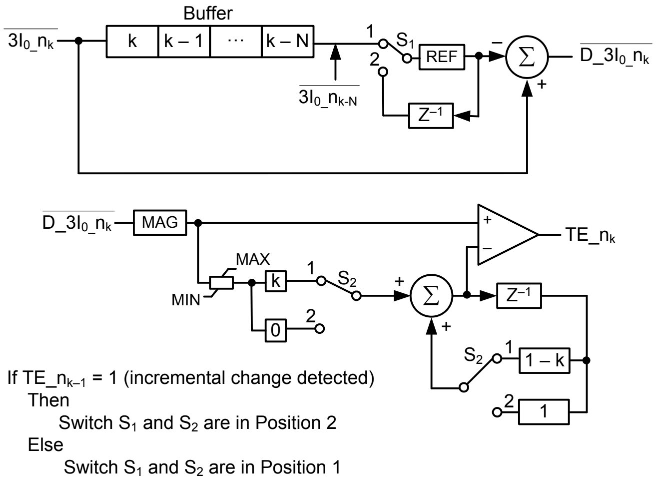

Fig. 7. Incremental detection logic used for detecting incremental changes in the $3I_0$ current of each individual feeder at a substation.

The logic used to determine which $3V_0$ busbar voltage is associated with the faulted feeder is similar to the incremental logic shown in Fig. 7. Should more than one busbar voltage indicate that it is associated with the faulted zone, then the busbar voltage that experienced the greatest incremental change in $3V_0$ will be associated with the fault, and that voltage will be used as the polarizing voltage (quantity) for the zero-sequence directional element.

If the feeder experiences an increment in its $3I_0$ current ($TE\_n_k = 1$ in Fig. 7), that feeder is identified as being involved in the fault.

If the feeder is involved in the fault, the reference value that the present value of $3I_0$ compared with is frozen (Switch S_1 in Fig. 7 is moved to Position 2). This is done to maintain the prefault reference. Similarly, the reference of the $3V_0$ busbar voltage associated with the fault is frozen. The assertion of the incremental logic also freezes the threshold reference that the incremental change of the $3I_0$ or $3V_0$ is compared with (Switch S_2 moves to Position 2).

If the output of the incremental logic is asserted, the zero-sequence incremental torque for that feeder will be calculated. If the output of the incremental logic for a feeder is not asserted (i.e., $TE\_n_k = 0$), the feeder is not involved with the fault and the incremental zero-sequence torque for that feeder will not be calculated, but simply set to zero as shown in (1).

$$
\begin{aligned}
&\text{If } TE\_n_k = 1 \\
&\quad \text{Then} \\
&\qquad TRQ\_n_k = \mathrm{Im}\left(D\_3V_0\_REF_k \cdot D\_3I_0\_n_k^{*}\right) \qquad (1) \\
&\quad \text{Else} \\
&\qquad TRQ\_n_k = 0
\end{aligned}
$$

where:

$D\_3V_0\_REF_k$ is the incremental change of the $3V_0$ voltage of the faulted busbar.

$D\_3I_0\_n_k$ is the incremental change of the feeder *n* $3I_0$ current.

* is the complex conjugate.

k is the present processing interval.

Once all of the incremental torque quantities have been calculated, we could simply select the faulted feeder as the one that developed the greatest incremental torque because of the SLG fault. However, to increase the confidence level in the identified faulted feeder and to address more complex faults that can occur, the results of the torque calculation are entered in a fault table. The first column in the fault table contains the absolute value of the calculated incremental zero-sequence torque, the second column contains the sign of the calculated incremental zero-sequence torque, and the third column contains the feeder name associated with the corresponding calculated incremental torque. The fault table is arranged in descending order of absolute incremental torque.

Table I is an example of how a fault table is composed for the example substation shown in Fig. 4. The number of rows in the fault table correspond to the number of feeders in the substation.

TABLE I
ABSOLUTE INCREMENTAL TORQUE, SIGN, AND IDENTITY FOR EACH FEEDER IN DESCENDING ORDER OF ZERO-SEQUENCE INCREMENTAL TORQUE

Number	Absolute Torque |TRQ_n|	Sign of Torque	Feeder ID
1	45	+	FDR_05
2	29	–	FDR_04
3	16	–	FDR_06
4	0	N/A	FDR_01
5	0	N/A	FDR_02
6	0	N/A	FDR_03

The feeder in the first row of the table gets declared as the faulted feeder if both of the following conditions are met:

- The sign of the incremental torque in the first row is positive.
- The signs of the incremental torque in the second and third rows are negative.

These described conditions are the most common for a typical SLG fault on an ungrounded power system. The faulted feeder experiences the highest positive incremental zero-sequence torque and all of the other feeders in the faulted zone generate lower negative incremental zero-sequence torques.

However, because we want the scheme to perform correctly for as many scenarios as possible and not only for the ideal scenario, we added extra criteria to the logic to correctly identify the faulted feeder or feeders. We describe two of these criteria in this paper. For the first case, consider a scenario when there are only two feeders in the faulted zone. In this instance, the incremental change of the $3I_0$ current for both of the feeders is the same irrespective of which one experiences an SLG fault. The result is that the absolute value of the incremental change of the zero-sequence torque developed by the two feeders because of the SLG fault is the same. The differentiator in this case is that for the faulted feeder, the incremental change in the zero-sequence torque is positive, whereas for the unfaulted feeder, the incremental change in the zero-sequence torque is negative.

Due to a possible rounding error in the torque calculations, the torque calculated for the unfaulted feeder may be slightly higher than for the faulted feeder, so it is input into the first row of the table instead of the second row. In this instance, the logic looks at the sign of the incremental torque in the first column. If it is negative, it looks at the sign of the incremental torque in the second column. If the sign in the second column is positive, the logic then compares the magnitude of incremental torque between the first two rows. If these two values are very close (within 5 percent of each other) and the sign of the incremental torque of the third column is not positive, then the feeder in the second row is declared as the faulted feeder.

Note that even though there may only be two feeders in the faulted zone, the substation will likely have more than two feeders. Because the logic defaults the incremental zero-sequence torque for the unfaulted feeder to zero, the sign gets set to N/A. When the logic checks the sign of the torque in the third row, it sees that it is N/A and not positive and allows a faulted feeder to be declared.

The second case we consider is one where two feeders simultaneously experience an SLG fault on the same phase (note that a simultaneous SLG fault on two different phases results in a phase-to-phase cross-country fault and requires one of the feeders to be taken out of service to allow further operation of the power system). In this case, the two faulted feeders experience the same incremental change in their $3I_0$ currents and, as a result, the incremental zero-sequence torque developed by these two feeders is the same in absolute magnitude and sign. All other nonfaulted feeders in the faulted zone develop lower negative incremental zero-sequence torques. When these values are input into the fault table rows, one and two contain the data for the faulted feeders. The data for the unfaulted feeder are in the remaining rows of the fault table.

In this case, the logic detects that the sign for the incremental torque is positive for the first and second rows and not positive for the remaining rows. The logic then checks the magnitude of the incremental zero-sequence torque developed by the feeders in the first two rows of the fault table. If these are approximately the same (within 5 percent of each other), the logic declares a simultaneous SLG fault on two feeders and identifies the faulted feeders as the feeders in the first two rows of the fault table.

From this explanation, it can be understood that entering the data in a fault table allows the logic to not only identify the faulted feeder for straightforward cases, but also allows the flexibility to deal with some special cases and allows the user the flexibility to design custom logic. The other advantage of the fault table is that it provides for increased confidence in the selection of the faulted feeder.

The CU forms the heart of the ground fault detection system proposed in this paper. It must receive and process time-aligned synchronized current and voltage quantities for all of the feeders in the system to detect faulted feeders. At the same time, the CU is required to provide data via a digital signal to the local human-machine interface (HMI) system and the supervisory control and data acquisition (SCADA) system. The main requirements of the CU are as follows:

- Deterministic performance of all local and remote modules (analog as well as I/O). The local and remote analog modules must be updated at a deterministic frequency to keep all of the modules synchronized. This enables accurate calculation of the incremental torque of each feeder. Because the remote I/O modules are synchronized via high-accuracy time pulses, highly accurate time-stamped sequence of event records are available.
- High-speed communications. EtherCAT communications provide high-speed, low-latency, deterministic, and reliable communications links between the CU and the remote modules. EtherCAT is an Ethernet-based fieldbus protocol designed exclusively for high-speed data acquisition and to serve control applications on a dedicated Ethernet network. EtherCAT messages can combine data from multiple EtherCAT nodes into a single message and can be as big as 4 gigabytes. EtherCAT can directly transfer data between modules without encoding or decoding messages, therefore providing a high-speed exchange of data between EtherCAT modules. This process is initiated by an EtherCAT master executing an application that starts the EtherCAT messages on a fixed interval and evaluates them on return. EtherCAT messages are designed to optimize the frame size [4] [5].
- Event recording and retrieval capabilities. The CU must be able to record sequential events records for all of the associated I/O distributed throughout the field.
- IEC 61131 logic engine. The CU must support IEC 61131-3 programming languages, providing the flexibility to write custom function blocks for torque calculation on feeders.
- High-speed processing. The CU must have high-speed processing capabilities to synchronously process the time-aligned data acquired via various I/O modules.
- Hardware modularity. The CU must have some expandability to allow use at multiple sites with different numbers and variations of combined analog and I/O modules.

A. System Architecture

A single EtherCAT frame contains analog and I/O point updates from multiple devices in an EtherCAT network, and the EtherCAT frame is shared between different analog and I/O modules [4]. A different mix of analog and I/O is possible by using different modules located in the same or different chassis. The analog and I/O modules in different processors share the same logic processor, providing advantages such as the synchronized sampling and processing of data and complete awareness of the bulk distribution system as a whole. Depending on the combination of different analog and I/O modules, various topologies such as star and daisy chain are possible. In this system, a daisy-chained network topology (shown in Fig. 8) was used because of the installation requirements. The EtherCAT messages from the different local and remote modules (field cabinets) had very deterministic behavior and low latencies due to the dedicated network for message exchange. However, other topologies can also be used without affecting the performance of the system.

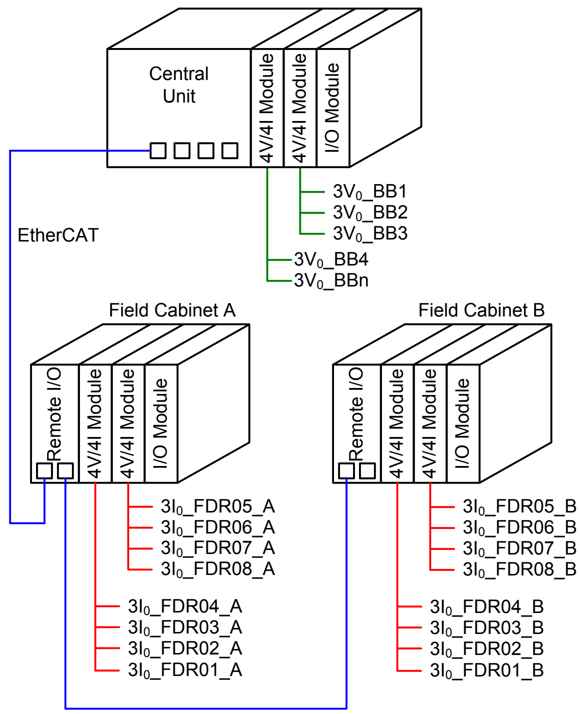

Fig. 8. EtherCAT nodes connected in a daisy-chain network topology.

B. Logic Explanation

The current and voltage quantities are sampled synchronously across the entire network. The individual modules (field cabinets in Fig. 8) are kept in synchronism with each other via a kilo pulse per second (kpps) signal sent from the CU to the field modules (cabinets). The kpps signal is input into a phase-lock loop (PLL) for conditioning before being used by each of the individual modules. In addition to synchronously sampling the analog signals, the processing (filtering) of the data in each module is done synchronously. The data is filtered using a finite impulse response (FIR) filter, as shown in Fig. 9. The output samples of the FIR filter are time-stamped for correlation and further processing in the CU.

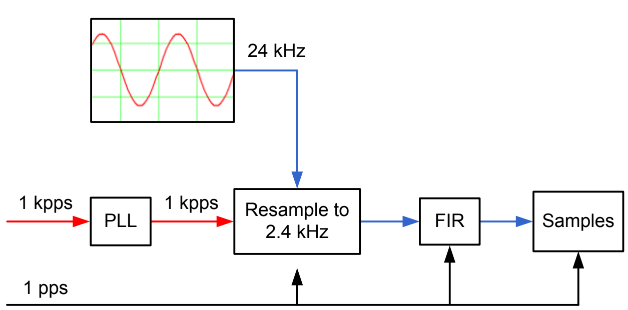

Fig. 9. Sampling logic.

The central logic processor provides the ability to run logic at two different processing intervals. This feature proves very helpful in segregating the high-speed protection class logic from the low-speed automation logic. IEC 61131-3 Structured Text (ST) and Continuous Function Chart (CFC) languages were used to program the CU. A modular approach was used to write the logic by creating function blocks of repetitive code, such as an infinite impulse response (IIR) filter and torque calculation to reduce the programming time and effort. Based on the incremental change in $3V_0$ and $3I_0$, torque was calculated for all of the feeders. The feeders were sorted in descending order based on magnitude and the direction in which the faulted feeder was detected. The indication of a faulted feeder and phase associated with the fault was done by generating the digital output (DO) signal and a SCADA signal for the SCADA system.

IV. Testing

After the proof of concept document was reviewed and approved by LADWP, the project moved into the next phase, which entailed that the proposed logic be programmed into a CU and tested under different operating and fault scenarios. The testing of the logic was divided into two stages. The first stage was testing the logic using a Real Time Digital Simulator (RTDS®). If this proved successful, testing would advance to the next stage—actual field testing at two LADWP substations.

A. RTDS Testing

An ungrounded power system similar to the one shown in Fig. 4 was modeled in an RTDS, and the CU interfaced with the RTDS to create a closed-loop system. By not transposing the individual phase conductors of the feeders in the RTDS model, a standing system $3V_0$ voltage and a standing $3I_0$ current for each feeder were created. To verify that the logic would not falsely assert during normal feeder switching operations, feeders were randomly transferred from one busbar to the other. Randomly switching feeders from one bus to the other did result in the standing $3I_0$ current of the feeders changing, but the incremental change in the $3I_0$ current was not large enough to exceed the dynamic threshold. This not only proved that the logic correctly handled normal feeder switching operations, but also that the threshold for the $3I_0$ current for each feeder was adaptive.

Afterward, the system was subjected to a variety of different SLG faults. Three fault criteria were changed during testing: the faulted feeder, the faulted phase, and the fault resistance (the latter was done to determine the sensitivity of the logic). After each fault, the output of the CU was inspected to verify that the feeder identified as the faulted feeder was indeed the feeder that was faulted in the simulations and that only one feeder was identified as the faulted feeder. In addition to this, the zero-sequence incremental torque developed by each feeder was recorded and verified using the incremental $3V_0$ of the faulted bus and the incremental $3I_0$ current of each feeder.

Once the implemented logic had correctly identified the faulted feeder for a single SLG fault, the robustness of the algorithm was tested by applying multiple SLG faults on the power system. For example, an A-phase-to-ground fault was applied to one feeder, and a few milliseconds later a second A-phase-to-ground fault was applied to a second feeder. Such faults are common on the LADWP system during storm conditions in which one or more feeders come into contact with vegetation. The simultaneous fault scenario was of particular interest to LADWP because it would not be possible to simulate such a fault in the field due to the field crew limitations. The logic had no issue in correctly detecting all of the faulted feeders. At this stage, LADWP had gained sufficient confidence in the logic and an invitation to do actual field testing was extended.

Before concluding RTDS testing, LADWP wanted to know where the present logic could also be used to detect an SLG fault on one of the substation busbars. Because the initial fault identification logic was not designed with this type of fault in mind, the logic needed to be modified. When one of the substation busbars experiences an SLG fault, all of the feeders connected to the faulted bus will see the fault behind them (i.e., the zero-sequence torque developed by each feeder is negative). After adding this condition to the logic, the logic was tested and could successfully detect an SLG busbar fault. To ensure that the modification to include busbar faults did not break the previously tested logic, a selected number of previous fault cases were rerun. As for the simultaneous case fault, the SLG busbar fault could not be field tested due to safety concerns. With the RTDS testing successfully concluded, it was time to test the logic in the field.

B. Field Testing

Field testing was done at two different LADWP substations to verify the system performance under real-world conditions.

The first series of tests was conducted on feeders supplied from Substation DS-80, which consists of 16 overhead feeders and two shunt capacitor banks. The week before testing commenced at DS-80, the CU was temporarily installed. The $3I_0$ feeder currents were obtained from existing summation current transformers (CTs) with a CT ratio of 50:1. The busbar $3V_0$ voltages were obtained from broken delta voltage transformers (VTs) with a ratio of 35:1. One feeder from DS-80 was selected for testing purposes. The SLG fault was simulated as follows: one end of an insulated conductor was connected to a ground and the other end was connected to one end of a fuse link. The other end of the fuse link was connected to one of the phase conductors of the feeder. The SLG fault was initiated by closing the fuse link. The picture in Fig. 10 shows a fuse link and an insulated conductor used to initiate an SLG fault on the feeder.

For the first fault, the ground was a sandy patch of soil (high-impedance fault), which resulted in a fault current of approximately 2 A primary (0.4 A secondary). The temporarily installed system successfully identified the faulted feeder, but the existing system could not detect the faulted feeder because the high-impedance ground fault did not generate enough $3V_0$ voltage to trigger the scheme.

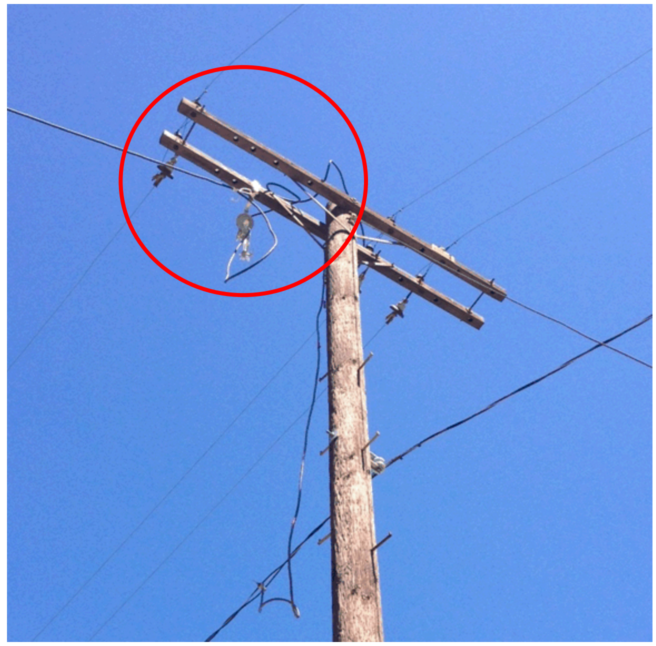

Fig. 10. A fuse link is used to create a connection between a phase on the feeder and an insulated conductor grounded at the other end. By closing the fuse link, an SLG fault is created.

For the second fault, a water pipe in an abandoned factory (see Fig. 11) was used as a ground. The fault current for this low-impedance fault was in the region of 5 A primary (0.1 A secondary), and both the temporary system and the existing system detected the fault and correctly identified the faulted feeder.

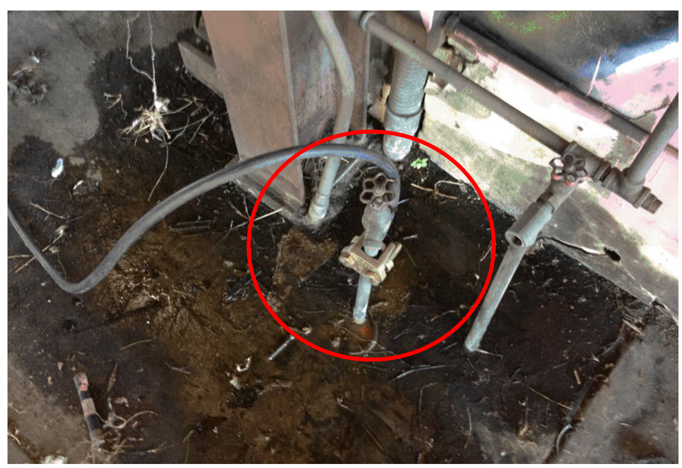

Fig. 11. Using a water pipe in an abandoned factory as the ground for the second fault case.

The second series of field tests was performed on underground cable feeders supplied from Substation DS-34, a dual busbar substation consisting of 18 underground feeder cables. The reason for selecting DS-34 was that, under normal operating conditions, the standing $3I_0$ current on the underground feeder cables is high. As in the case for DS-80, the CU was temporarily installed into DS-34 a week before testing began.

Because Substation DS-34 supplies the heart of the garment business district in Los Angeles, testing had to be done within a very tight time schedule and be completed before the start of business. Unlike the testing at DS-80, several feeders were selected to be faulted during this series of testing. After the initial fault, several feeders indicated that they had experienced the fault condition. At this stage, testing was temporarily halted so as to determine the reason for the incorrect operation of the fault identification logic.

After examining the incremental zero-sequence torque quantities developed by the unfaulted feeders, we determined that the polarity of the summation CTs from several of the feeders that input into the centralized protection scheme were incorrect. (In general, if two or more feeders are faulted simultaneously, the zero-sequence incremental torque developed by these feeders would be equal because the total fault current would be distributed equally amongst the faulted feeders.) After correcting the polarity of the summation CTs, testing was resumed and the fault identification logic operated as designed. The centralized scheme not only correctly identified the faulted feeder but also the faulted phase. Typical fault current for an SLG fault on feeders from DS-34 were in the range of 0.4 to 0.6 A primary (0.08 to 0.012 A secondary). For visibility, separate DOs were configured on the front panel of the CU so as to indicate both the faulted feeder or feeders and the faulted phase.

An oscillographic event report of the fault current from the fault testing at Substation DS-34 is shown in Fig. 12. The zero-sequence current before and during the fault are shown in Fig. 12. Note that the standing zero-sequence current is for a very lightly loaded feeder.

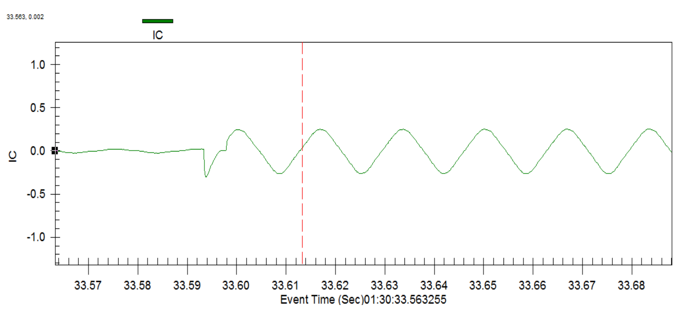

Fig. 12. A current waveform capture from Field Cabinet B during field testing.

V. Conclusion

Determining which feeder or feeders is experiencing an SLG fault in an ungrounded power system where there is a definite association between the feeder $3I_0$ current and the $3V_0$ voltage is a relatively straightforward task. However, faulted feeder identification on an ungrounded power system where there is no direct correlation between the feeder $3I_0$ current and the available $3V_0$ voltage is more challenging. Simply routing the highest $3V_0$ voltage of all the buses to all of the feeders at a substation could result in the fault detection scheme (protection) declaring multiple feeders as being faulted.

One method that this paper discusses to correctly identify a faulted feeder in an ungrounded power system where there is no direct correlation between the $3I_0$ current of a feeder and the available $3V_0$ voltages is to route all the $3I_0$ currents and $3V_0$ bus voltages to a CU. With all of the $3I_0$ currents and $3V_0$ voltages in one central location, a virtual relationship is created between all of the feeders involved in the SLG fault and the corresponding $3V_0$ voltage. Only the feeders involved in the fault experience an incremental $3I_0$ current, and the associated $3V_0$ voltage experiences an incremental change. By calculating the incremental zero-sequence torque developed by each feeder, the faulted feeder or feeders can be identified. Faulted feeders are those that develop a positive zero-sequence incremental torque. All nonfaulted feeders involved in the fault develop a negative zero-sequence incremental torque. In general, faulted feeders also develop the largest absolute torque value. All remaining feeders not involved in the fault do not experience an incremental change in their $3I_0$ current and therefore do not develop an incremental zero-sequence torque.

By using the incremental $3I_0$ currents and $3V_0$ voltages, a virtual correlation between feeders involved in a fault and the corresponding $3V_0$ voltages was created. This allowed the faulted feeder or feeders to be identified in a system where there is no definite correlation between the feeder $3I_0$ currents and the $3V_0$ bus voltages.

VI. Future of the Project

This system is currently being designed into several substations. Some are replacements of the original system and the remainder are stations without ground fault detection. A library of the algorithm was created to be installed in the controller. This library allows LADWP or their contractors to easily configure the new distribution substations. The configuration of a system takes less than two hours per substation.

LADWP has 120 distribution substations and approximately 1,700 4.8 kV distribution feeder circuits that will benefit from the accurate detection of ground faults on the ungrounded delta distribution system. The success of the field tests indicates that LADWP can look forward to a tremendous improvement in terms of quality of service and safety of the power system. The first 30 substations are presently in the design stage, with more on the way.

Future plans involve implementing and testing this method using synchrophasor data from the feeder relays. This will eliminate the need for separate hardware for CT and VT connections and will significantly reduce the installation cost and time.

VII. References

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VIII. Biographies

Douglas Kirby received a BSEE degree with a specialization in Power Engineering from Purdue University, West Lafayette, Indiana, in 1985. He joined Los Angeles Department of Water and Power (LADWP) in 1985 as an Electrical Engineer. He currently is in charge of the Protection and Control Department at LADWP. Douglas is a registered professional engineer in California.

Normann Fischer received a Higher Diploma in Technology, with honors, from Technikon Witwatersrand, Johannesburg, South Africa, in 1988; a BSEE, with honors, from the University of Cape Town in 1993; and an MSEE from the University of Idaho in 2005. He joined Eskom as a protection technician in 1984 and was a senior design engineer in the Eskom protection design department for three years. Normann then joined IST Energy as a senior design engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories, Inc. as a power engineer in the research and development division. Normann was a registered professional engineer in South Africa and a member of the South African Institute of Electrical Engineers. He is currently a member of IEEE and ASEE.

Amandeep Kalra is an automation engineer with Schweitzer Engineering Laboratories, Inc. (SEL) in Pullman, Washington, with several years of experience in designing automation systems and communications networks. He has authored numerous technical papers focusing on Ethernet networks and Ethernet-based communications protocols as well as IEC 61850 communications standards. He has represented SEL at international conferences and IEC 61850 interoperability demonstrations organized by UCA and frequently teaches engineering design and application of IEC 61850 solutions. He has a bachelor of technology degree in instrumentation and control engineering from the National Institute of Technology, India, and a master's degree in electrical engineering from California State University, Northridge.

Dennis Haes is a senior engineer in the engineering services division of Schweitzer Engineering Laboratories, Inc. in Pullman, Washington. He has over 20 years of experience with substation automation and 13 years of electric utility operations experience with a large utility. Dennis obtained his bachelor of science degree in electrical engineering from New Mexico State University. He is a member of IEEE.

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